Katherine E. Smith
Managing Counsel – State Regulatory

Law Department
80 Park Plaza, T10, Newark, New Jersey 07102-4194
(Tel.) 717-329-0360
Email: Katherine.Smith@pseg.com

PSEG
Services Corporation

December 29, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J. No. 17
Electric and B.P.U.N.J. No. 17 Gas,
and for Changes in Depreciation Rates,
Pursuant to *N.J.S.A.* 48:2-18,
N.J.S.A. 48:2-21 and *N.J.S.A.* 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. _____

VIA BPU E-FILING SYSTEM & ELECTRONIC MAIL
Sherri Golden, Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Golden:

Enclosed for filing with the Board of Public Utilities ("Board" or "BPU") is the Verified Petition (Exhibit P-1) of Public Service Electric and Gas Company ("PSE&G," "Public Service," the "Company," or "Petitioner") in the above-entitled matter.

This is PSE&G's first comprehensive electric and gas base rate case in nearly six years, and is filed on schedule pursuant to prior orders of the BPU requiring PSE&G to file a base rate case before January 1, 2024. A main component of this case is the recovery of over $3 billion in capital investments made to strengthen and modernize the state's electric and gas infrastructure since PSE&G's base rates were last set in 2018. Those investments include:

- gas main replacements that reduce carbon emissions;
- electric life cycle replacements that improve reliability;
- Advanced Metering Infrastructure (AMI) that provides more customer insight into the electric bill and greater opportunity to save money; and
- electric vehicle ("EV") infrastructure programs to ease a customer's transition to EV use.

PSE&G is proud of its success in keeping its customers' bills affordable. Over the past 15 years, the affordability of PSE&G bills has improved by approximately 40%, as household income increased materially more than our electric and gas rates. A PSE&G combined electric and gas bill currently comprises less than 3% of New Jersey household income for median-income customers, and less than 2% of household income for low-income customers who take advantage of available payment support programs. With this filing, the percentage of household income will remain at about 3% for median-income and about 2% for low-income customers who take advantage of payment support programs.

While maintaining this level of affordability, PSE&G consistently receives accolades for its performance and customer service. Last month, PSE&G was awarded the 2023 ReliabilityOne® Award for Outstanding Metropolitan Service Area Reliability Performance in the Mid-Atlantic Region—for the 22nd consecutive year—and the national 2023 ReliabilityOne® Outstanding Customer Engagement Award. In 2022, J.D. Power named PSE&G number one in customer satisfaction for both Residential Electric and Natural Gas Service in the East among Large Utilities. In 2023, J.D. Power named PSE&G number one in customer satisfaction for both Residential Electric and Business Electric Service in the East among Large Utilities.

In addition to PSE&G's request to recover its traditional utility investments to modernize and improve the electric and gas systems, this filing also proposes programs that will provide customers with increased options that allow them to use electricity how and when they want to. PSE&G is proposing a new time-of-use rate that will allow customers to save on their bills by shifting usage to off-peak periods. This rate option provides benefits to all customers, including by encouraging residential customers to charge their electric vehicles during off-peak periods.

PSE&G also proposes several mechanisms that will mitigate the impacts of market volatility on customers, so that bills do not fluctuate for reasons beyond customers' or PSE&G's control. Those proposals include insulating customer rates from swings in interest rates, pension earnings, and the cost of severe weather events, providing a more predictable monthly bill.

Attached in support of the Company's petition are the Direct Testimonies of the following witnesses:

Exhibit	**Witness**	**Area of Responsibility**
Exhibit P-2	Michael McFadden, Director, Sales and Revenue Forecasting	Overall financial policy and revenue requirements
Exhibit P-3	Panel Testimony -- Michael Schmid, Vice President, Asset Management and Planning and Ricardo G. Fonseca, Senior Director, Utility Finance	Electric and gas operations, capital expenditures, and electric and gas distribution-related O&M expense
Exhibit P-4	Clifford Pardo, Vice President – Tax PSEG Services Company	Tax expense, accumulated deferred income tax and tax benefit flow-back; Consolidated Tax Adjustment
Exhibit P-5	Ann E. Bulkley, The Brattle Group	Return on equity, capital structure, financial environment

Exhibit P-6	Michael Adams, Concentric Energy Advisors	Benchmarking of PSE&G's financial and operational performance
Exhibit P-7	John J. Spanos, Gannett Fleming	Depreciation
Exhibit P-8	Michael Adams, Concentric Energy Advisors	Lead/lag study, cash working capital
Exhibit P-9E, Exhibit P-9G	Stephen Swetz, Senior Director – Rate and Regulation, PSE&G	Cost of service, rate design, and tariff submissions
Exhibit P-10	Ahmad Faruqui, Principal Emeritus, The Brattle Group	Time-of-Use Rates
Exhibit P-11	Karen Reif, Vice President Renewables & Energy Solutions	CEF-EV implementation
Exhibit P-12	David Johnson, Vice President Customer Care and Chief Customer Officer	Advanced Metering Infrastructure, CEF-EC implementation

In his testimony concerning consolidated taxes (Exhibit P-4), Mr. Pardo refers to certain tax data that contain confidential financial information. This material will be furnished upon execution of a Confidentiality Agreement between the Company, BPU Staff, and the Division of Rate Counsel ("Rate Counsel") and its consultants. A Confidentiality Agreement in a form recently used by the BPU and Rate Counsel is attached hereto for review and execution.

PSE&G requests that the Board address the issues in this proceeding in as thorough and efficient a manner as possible. PSE&G is confident that its filing and the Board's review will support the fact that the Company's requested rate relief is essential to maintaining the necessary electric and gas distribution infrastructure and services required to serve our customers in a safe, adequate, proper and reliable manner.

Consistent with the Order issued by the New Jersey Board of Public Utilities ("BPU or Board") in connection with *I/M/O the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, this filing is being electronically filed with the Secretary of the Board and the New Jersey Division of Rate Counsel. No paper copies will follow.

Please be assured that the Company will work diligently with all parties to the proceeding to help bring this matter to closure in as timely and equitable a manner as is possible. We request that the Board, at its earliest convenience, establish a procedural schedule and/or transfer this proceeding to the Office of Administrative Law so as to render a final decision before the proposed rate effective date of January 29, 2024.

Very truly yours,

Katherine E. Smith

cc: Attached service list

BPU
Carol Artale
Board of Public Utilities
44 South Clinton Avenue
9th Floor
Trenton NJ 08625-0350
carol.artale@bpu.nj.gov

BPU
William Barkasy
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
william.barkasy@bpu.nj.gov

BPU
Cindy Bianco
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
cindy.bianco@bpu.nj.gov

BPU
David Brown
Board of Public Utilities
44 South Clinton Avenue
Suite 314
P.O. Box 350
Trenton NJ 08625-0350
david.brown@bpu.nj.gov

BPU
Malike Cummings
Board of Public Utilities
44 S. Clinton Avenue
P.O. Box 350
Trenton NJ 08625
malike.cummings@bpu.nj.gov

BPU
Anthony DeAnni
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
anthony.deanni@bpu.nj.gov

BPU
Jacqueline Galka
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 984-4657
Jacqueline.Galka@bpu.nj.gov

BPU
Michael Hunter
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
michael.hunter@bpu.nj.gov

BPU
Michael Kammer
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
mike.kammer@bpu.nj.gov

BPU
Bart Kilar
Board of Public Utilities
44 South Clinton Avenue
9th Floor
P.O. Box 350
Trenton NJ 08625-0350
bart.kilar@bpu.nj.gov

BPU
Yanina Lepore
Board of Public Utilities
44 South Clinton Avenue
9th Floor
P.O. Box 350
Trenton NJ 08625
yanina.lepore@bpu.nj.gov

BPU
Jacqueline O'Grady
Board of Public Utilities
44 South Clinton Avenue
9th Floor
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-2947
jackie.ogrady@bpu.nj.gov

BPU
Stacy Peterson
Board of Public Utilities
44 South Clinton Avenue
9th Floor
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-4517
stacy.peterson@bpu.nj.gov

BPU
Farhana Rahman
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
farhana.rahman@bpu.nj.gov

BPU
Scott Sumliner
Board of Public Utilities
44 South Clinton Avenue
9th Floor
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-4519
scott.sumliner@bpu.nj.gov

BPU
Dean Taklif
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 777-0193
dean.taklif@bpu.nj.gov

BPU
Andrew Tuzzo
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
andrew.tuzzo@bpu.nj.gov

BPU
Dari Urban
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
dari.urban@bpu.nj.gov

BPU
Heather Weisband
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton NJ 08625
heather.weisband@bpu.nj.gov

BPU
Benjamin Witherell
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
benjamin.witherell@bpu.nj.gov

DAG
Michael Beck
NJ Dept. of Law and Public Safety
25 Market Street
P.O. Box 112
Trenton NJ 08625
michael.beck@law.njoag.gov

DAG
Steven Chapler
NJ Dept. of Law and Public Safety
25 Market Street
P.O. Box 112
Trenton NJ 08625
steven.chaplar@law.njoag.gov

DAG
Daren Eppley
NJ Division of Law & Public Safety
Richard J. Hughes Justice Complex
Public Utilities Section
25 Market Street, P.O. Box 112
Trenton NJ 08625
daren.eppley@law.njoag.gov

DAG
Matko Ilic
NJ Dept. of Law and Public Safety
Richard J. Hughes Justice Complex
Public Utilities Section
25 Market Street, P.O. Box 112
Trenton NJ 08625
matko.ilic@law.njoag.gov

DAG
Pamela Owen
NJ Dept of Law & Public Safety
Division of Law, Public Utilities Section
R.J. Hughes Justice Complex
25 Market Street, P.O. Box 112
Trenton NJ 08625
Pamela.Owen@law.njoag.gov

PSE&G
Joseph F. Accardo, Jr.
PSEG Services Corporation
80 Park Plaza, T10
P.O. Box 570
Newark NJ 07102
(973) 430-5811
joseph.accardojr@pseg.com

PSE&G
Aaron I. Karp
PSEG Services Corporation
80 Park Plaza, T10
P.O. Box 570
Newark NJ 07102
(973)-430-8970
aaron.karp@pseg.com

PSE&G
Danielle Lopez
Public Services Corporation
80 Park Plaza, T10
P.O. Box 570
Newark NJ 07102
973-430-6479
danielle.lopez@pseg.com

PSE&G
Stacey M. Mickles
PSEG Services Corporation
80 Park Plaza, T-10
P.O. Box 570
Newark NJ 07102
stacey.mickles@pseg.com

PSE&G
Bernard Smalls
PSEG Services Corporation
80 Park Plaza-T10
P.O. Box 570
Newark NJ 07102-4194
(973) 430-5930
bernard.smalls@pseg.com

PSE&G
Katherine E. Smith
PSEG Services Corporation
80 Park Plaza, T10
P.O. Box 570
Newark NJ 07102
(973) 430-6996
katherine.smith@pseg.com

PSE&G
Matthew M. Weissman
PSEG Services Corporation
80 Park Plaza, T10
P.O. Box 570
Newark NJ 07102
(973) 430-7052
matthew.weissman@pseg.com

PSE&G
Caitlyn White
PSEG Services Corporation
80 Park Plaza, T-10
P.O. Box 570
Newark NJ 07102
(973)-430-5659
caitlyn.white@pseg.com

Rate Counsel
Annette Cardec
Division of Rate Counsel
140 East Front Street
4th Floor
Trenton NJ 08625
acardec@rpa.nj.gov

Rate Counsel
Maura Caroselli
Division of Rate Counsel
140 East Front Street
4th Floor
Trenton NJ 08625
mcaroselli@rpa.nj.gov

Rate Counsel
Robert Glover
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
rglover@rpa.nj.gov

Rate Counsel
Christine M. Juarez
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
cjuarez@rpa.state.nj.us

Rate Counsel
Debora Layugan
Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton NJ 08625
dlayugan@rpa.nj.gov

Rate Counsel
Brian O. Lipman
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
blipman@rpa.nj.gov

Rate Counsel
Megan Lupo
New Jersey Division of Rate Counsel
140 East Front Street, 4th Floor
P.O. Box 003
Trenton New Jersey 08625
mlupo@rpa.nj.gov

Rate Counsel
Mamie Purnell
Division of Rate Counsel
140 East Front Street, 4th Flr.
Trenton NJ 08625
mpurnell@rpa.nj.gov

Rate Counsel
Bethany Rocque-Romaine
Division of Rate Counsel
140 East Front Street 4th Floor
Trenton New Jersey 08625
bromaine@rpa.nj.gov

Rate Counsel
Sarah Steindel
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
ssteinde@rpa.nj.gov

Rate Counsel
Emily Smithman
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
esmithman@rpa.nj.gov

Rate Counsel
David Wand
Division of Rate Counsel
140 East Front Street
4th Floor
Trenton NJ 08625
dwand@rpa.nj.gov

Rate Counsel
Brian Weeks Esq.
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
bweeks@rpa.state.nj.us

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN ELECTRIC AND GAS RATES AND FOR CHANGES IN THE TARIFFS FOR ELECTRIC AND GAS SERVICE, B.P.U.N.J. NO. 17 ELECTRIC AND B.P.U.N.J. NO. 17 GAS, AND FOR CHANGES IN DEPRECIATION RATES, PURSUANT TO *N.J.S.A. 48:2-18*, *N.J.S.A.* 48:2-21 AND *N.J.S.A.* 48:2-21.1, AND FOR OTHER APPROPRIATE RELIEF	)	PETITION BPU DOCKET NOS. _____

Public Service Electric and Gas Company ("PSE&G," "Public Service," the "Company," or "Petitioner"), a corporation of the State of New Jersey that is subject to the jurisdiction of the Board of Public Utilities ("Board" or "BPU") and that has its principal offices at 80 Park Plaza, Newark, New Jersey, 07102, hereby petitions this Honorable Board for authority pursuant to *N.J.S.A.* 48:2-18, *N.J.S.A.* 48:2-21, *N.J.S.A.* 48:2-21.1, *N.J.A.C.* 14:1-5.7, and *N.J.A.C.* 14:1-5.12 to increase its tariff rates and charges for electric and gas service, to change its depreciation rates, and to implement certain other tariff revisions. In support of this Petition, PSE&G states as follows:

I. PETITIONER

1. Petitioner is engaged in the distribution of electricity and the provision of electric Basic Generation Service ("BGS"), and is engaged in the distribution of gas and the provision of Basic Gas Supply Service ("BGSS"), for residential, commercial, and industrial purposes within the State of New Jersey. PSE&G provides service to approximately 2.3 million electric and 1.9 million gas customers in an area having a population of approximately

6.5 million persons, and that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to Camden, New Jersey. Petitioner is subject to the Board's jurisdiction for the purposes of setting its retail distribution rates and to assure safe, adequate, and proper electric distribution and natural gas distribution service pursuant to *N.J.S.A.* 48:2-21, *et. seq*. and *N.J.S.A.* 48:2-23.

II. THE CONTEXT OF THIS PETITION

2. This filing is being made, in part, to comply with the BPU's May 22, 2018 Order approving the second phase of PSE&G's Gas System Modernization Program ("GSMP II").[1] The GSMP II Order required the filing of a base rate case by no later than January 1, 2024.[2] In addition, the Board's approval of the Company's filing for a second Energy Strong program ("Energy Strong II") also required the Company to file a base rate case no later than December 31, 2023.[3] PSE&G submits this filing in compliance with those Orders.

3. PSE&G seeks approval to increase annual revenue requirements for both its electric and gas operations. The increase primarily is driven by:

---

[1] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II")*, BPU Docket No. GR17070776, "Decision and Order Approving Stipulation" (May 22, 2018) ("GSMP II Order").

[2] An identical requirement is present in the following Board orders: *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, BPU Docket No. EO18101115, Decision and Order Approving Stipulation (January 7, 2021) ("CEF-EC Order"); and *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, BPU Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

[3] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Second Energy Strong Program* ("Energy Strong II"), BPU Docket Nos. EO18060629 and GO18060630, "Final Decision and Order Approving Stipulation" (September 11, 2019) ("Energy Strong II Order").

- Board-approved and traditional utility investments to modernize the electric and gas system, maintain and improve reliability and customer satisfaction, and reduce carbon emissions; and
- Deferred costs related to major storm events.

PSE&G's customers have recognized the value of these investments and expenditures and of PSE&G's prudent operating practices, as shown in the Company's reliability results and customer satisfaction ratings from J.D. Power.[4]

4. In this filing PSE&G also seeks:

(a) a prudency determination and final rate recovery on the following programs:

i. NJ Transit Mason Substation ("Mason" or "Mason Station");[5]

ii. GSMP II;

iii. Energy Strong II; and

iv. Clean Energy Future – Energy Cloud ("CEF-EC").

(b) a prudency determination and recovery of investments and expenditures associated with the Company's Clean Energy Future – Electric Vehicles program ("CEF-EV") investments that are in-service;[6]

[4] *See* Direct Testimony of Michael J. Adams, submitted herewith, at 30-32 and associated Schedules (demonstrating PSE&G's consistently high, generally first-quartile J.D. Power scores over the past ten years).

[5] *See I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Construction of the Mason Substation Damaged During Superstorm Sandy*, BPU Docket No. EO16080788, Decision and Order Approving Stipulation (November 21, 2017).

[6] *See* CEF-EV Order.

(c) recovery of the investments in the Energy Strong II, GSMP II, and Infrastructure Advancement Program ("IAP") programs that are not subject to interim recovery (referred to as "Stipulated Base").[7]

For the Mason Station, CEF-EC, and CEF-EV programs, there was no interim recovery approved prior to this petition and recovery for all in-service expenditures will commence from this rate case proceeding. The CEF-EV and IAP programs will continue to have investment beyond the end of this proceeding that will require final prudency determination on all expenditures in a subsequent rate case.

5. PSE&G's most recent electric and gas distribution base rate case was resolved in October 2018.[8] Since that time, PSE&G has provided excellent service at reasonable rates, while making significant, long-lived investment in the system. During this time, PSE&G has been able to control costs and maximize the value of its prior investments. As a result, the distribution component of a residential electric customer bill for a typical customer has increased at a rate that is below the rate of inflation, well below the statewide average for PSE&G's peers.

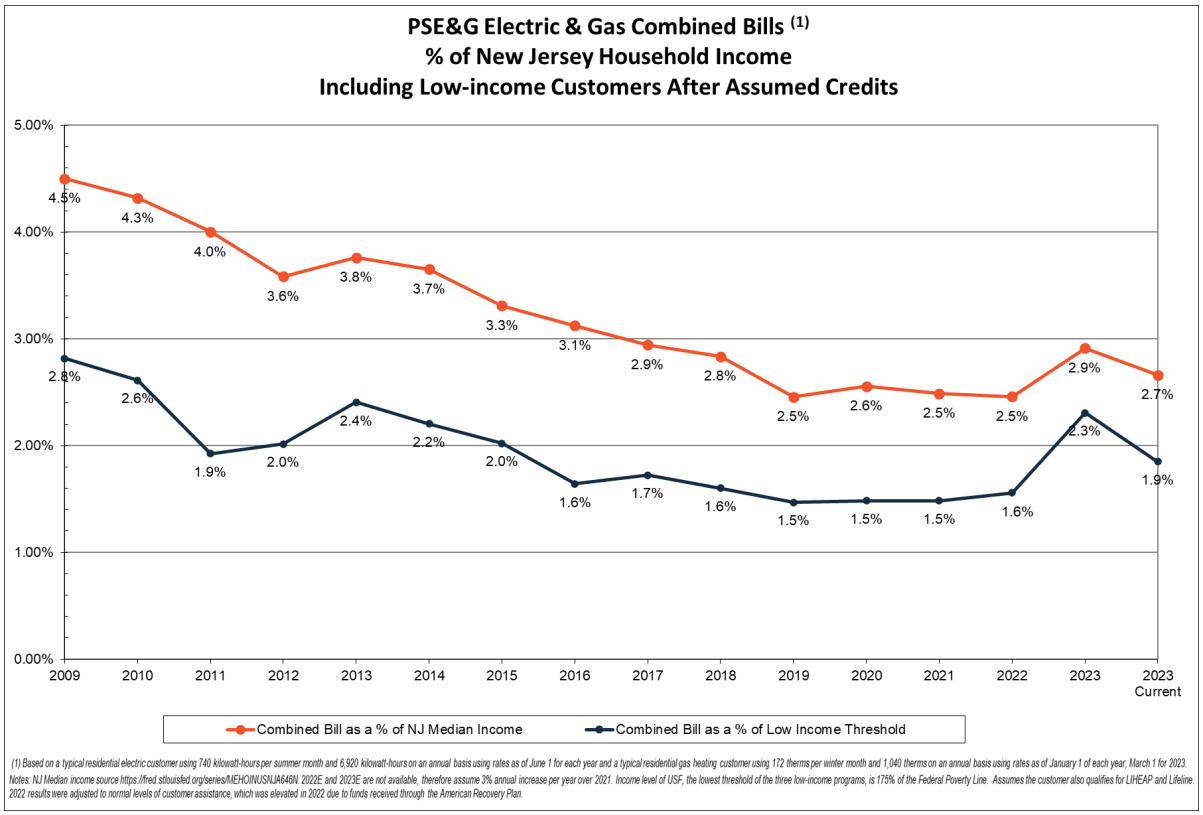
---

[7] *See I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Infrastructure Advancement Program (IAP)*, BPU Docket Nos. EO21111211 and GO21111212, Decision and Order Approving Stipulation ("IAP Order") (June 29, 2022).

[8] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018).

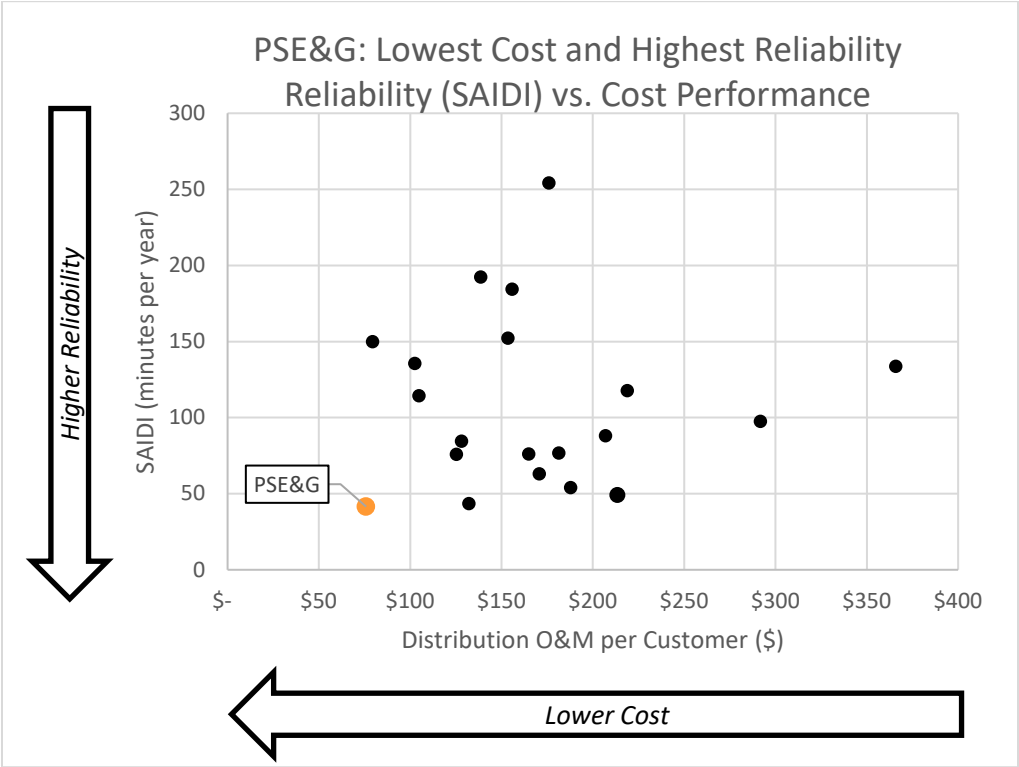
6. Similarly, the distribution component of a residential gas customer bill has increased since the previous base rate case, primarily as the result of GSMP II rate adjustments for work that provides both reliability and carbon emissions benefits. Despite the considerable investment to modernize the gas system, the percentage increase since PSE&G's most recent base rate case is less than half of the statewide average percentage increase for gas bills in that time period. Again, PSE&G's gas distribution rates are considerably less than the New Jersey average because the Company has been able to control costs and maximize the value of its prior investments.

7. In fact, the relative cost of PSE&G's services to a typical combined (*i.e.*, electric and gas) residential customer has dropped significantly since 2009. The chart below tracks the bill as a percentage of income for a typical combined residential customer relative to the State's median income (in the orange line), and the bill as a percentage of income for low-income customers (in the blue line):



For the average residential customer, the cost of service is less than 3% of median income - - far lower than in 2009. For low-income residents, the cost of the bill after receiving available grants, relative to an income threshold of 60% of State median income (the level at which a customer is eligible for these grants), is currently less than 2% today. So, even with the rate increase proposed herein, the cost of electricity and gas for all PSE&G customers, including low-income customers, remains a very small portion of overall income.

8. Even at these relatively low customer costs, PSE&G remains the most reliable electric utility among its peers, as demonstrated here:



III. PRIMARY DRIVERS OF THIS RATE REQUEST

9. As a result of the Company's execution of a very successful strategy of cost mitigation and expense control, PSE&G has operated for more than five years since its last request for a base rate increase. Since then, despite the Company's successful execution of cost mitigation and expense control strategies, a number of significant factors have driven the Company's financial results well below its authorized rate of return. These factors impact the rate increase sought in this filing, and are summarized below.

10. The Company has invested a substantial amount of capital to maintain, upgrade, and harden its system, incurring significant operating costs that are not reflected in rates. The key drivers of this rate request include recovery of Board-approved capital investments and deferrals, and resets of Board-approved cost recovery clauses such as

stipulated base program and deferred recovery on investments for Energy Strong II, GSMP II, IAP, the CEF-EC program for installation of advanced meter infrastructure or "AMI," the CEF-EV Program, and the Mason Station project, along with other significant capital expenditures.

11. Gross plant approved in PSE&G's last electric distribution base rate case has increased by approximately $2.6 billion through October 31, 2023, with an additional $1.1 billion of investment planned through November 30, 2024, inclusive of all accelerated infrastructure investments. The Petitioner's current electric rates do not reflect an adequate return on the Company's invested capital dedicated to the service of the Company's electric customers. This capital investment far exceeds the amount the Company is recovering in depreciation expense in current rates and increases the Company's rate base and the depreciation expense needed to recover this investment. PSE&G is seeking recovery of and on all prudent investment in this proceeding.

12. Similarly, gross plant approved in PSE&G's last gas distribution base rate case has increased by approximately $3.8 billion through October 31, 2023, with an additional $1.1 billion of investment planned through November 30, 2024, inclusive of all accelerated infrastructure investments. The Petitioner's current gas rates do not reflect an adequate return on the Company's invested capital dedicated to the service of the Company's gas customers. This capital investment far exceeds the amount the Company is recovering in depreciation expense in current rates and increases the Company's rate base and the depreciation expense needed to recover this investment. PSE&G is seeking recovery of and on all prudent investment in this proceeding.

13. Additionally, PSE&G's working capital needs have increased. The primary driver is an increase in the Company's cash working capital needs, as since the last base rate case, PSE&G has seen a significant increase in the collection lag from customers. The Company has also seen increased materials and supplies needs, because of preparation for planned increases for system maintenance and capital work, and in response to supply chain constraints that have led the Company to diversify suppliers and revamp material forecasting models.

14. Other drivers of the rate increase sought in this filing include the following: the insufficiency of the Company's current depreciation rates, including cost of removal; New Business investment with flat sales, as compared with sales at the time of the Company's prior base rate case in 2018; and PSE&G's unrecovered incremental storm costs of approximately $109 million.

15. PSE&G has taken steps to mitigate rate increases, including steps taken to control costs, including wages and pension costs. The Company also continues to provide customer benefits through PSE&G's Appliance Service Business. In addition, this filing includes a proposal to increase the flow-back of certain tax benefits to customers, which also mitigates the rate increase requested in this filing.

16. PSE&G has made substantial capital improvements to its electric and gas distribution infrastructure, with stable, competitive rates, while preserving operational performance.

17. In fact, PSE&G has received numerous awards related to both its electric and gas distribution reliability and performance since its last rate case. PSE&G has been named

the most reliable utility in the Mid-Atlantic region/service area every year since 2002 by the PA Consulting Group. In 2022, PSE&G also achieved a first-place ranking from J.D. Power in the East among large utilities for both gas and electric utility residential customer satisfaction studies. PSE&G has also received additional awards, including recognition from both the Edison Electric Institute ("EEI") and the American Gas Association ("AGA"), which are detailed in the panel testimony of Company witnesses Mr. Michael A. Schmid and Mr. Ricardo G. Fonseca.

18. PSE&G achieves this performance while still maintaining a stellar safety record. According to the most recent results, PSE&G ranks in the top quartile in the Occupational Safety and Health Administration ("OSHA") measure for "Recordable Incidence Rate," and in the top decile for OSHA's "Days Away Rate." PSE&G also ranks in the top quartile of "Damages Per 1,000 Locate Requests," which calculates the number of overall damages to gas and electric facilities per 1,000 locate or "mark out" requests, demonstrating how PSE&G's safety culture benefits all individuals who live and/or work in PSE&G's service territory. More detail is provided in the panel testimony of Mr. Schmid and Mr. Fonseca.

19. This Petition, along with its supporting testimony and schedules, establishes that the proposed rates for electric and gas service are necessary to provide sufficient operating revenues to meet operating expenses, taxes and fixed charges, maintain its financial viability, and provide a reasonable rate of return on Petitioner's investment in its electric and gas property.

20. Petitioner's requests should be approved to maintain PSE&G's credit-worthiness at a level sufficient to cost-effectively raise capital to enable the provision of safe, adequate, proper and reliable service to its electric and gas customers.

IV. PETITIONER'S PROPOSAL IN THIS CASE

21. Petitioner requests the approval of electric and gas rates based upon the test year ending May 31, 2024, as adjusted for known and measurable costs with respect to rate base, Operations and Maintenance ("O&M") expenses, revenues, and capital structure. The table below illustrates the breakdown of the net rate increase sought in this proceeding. Beyond the proposed base rate increase, the Company also seeks: (1) recovery of storm costs through a new clause component rather than through base rates, (2) recovery of gas bad debt expense through a new component of the Societal Benefits Charge ("SBC") rather than through base rates, and (3) an adjustment to flow-back certain tax benefits to customers through the Tax Adjustment Credit ("TAC").

Table 1

Rate Case Net Impact to Customers

Overall Total Revenue Impact ($M)	**Electric**	**Gas**	**Total**
Base Rates	$522	$423	$945
Tax Adjustment Credit ("TAC")	-$98	-$102	-$200
Storm Recovery Mechanism	$38	$1	$39
Gas Bad Debt in SBC	$0	$42	$42
Net Total Revenue Impact $	$462	$364	$826
Net Total Bill Impact %	8%	11%	9%

22. The proposed Tariff for Electric Service (Schedule 1, supported by the testimony of Mr. Stephen Swetz), is designed to produce approximately $462 million in additional operating revenue on an annual basis, resulting in a total bill increase of

approximately 8% for all electric distribution customers.[9] The actual percentage increase applicable to specific customers will vary according to the applicable rate schedule.

23. The proposed Tariff for Gas Service (Schedule 3, also supported by Mr. Swetz), is designed to produce approximately $364 million in additional operating revenue on an annual basis, resulting in a total bill increase of approximately 11% for all gas distribution customers. The actual percentage increase applicable to specific gas customers will vary according to the applicable rate schedule.

24. The Company proposes to shape the TAC amortization to decline over an approximately five-year period to avoid a significant impact to customers after the final year of the amortization. These annual impacts are discussed in detail in the testimony of Mr. Swetz.

25. Petitioner proposes that the tariffs proposed in this filing go into effect no later than January 29, 2024, a date more than 30 days from the date of this filing.

V. COST CONTAINMENT AND OTHER MITIGATION TECHNIQUES, INCLUDING THE CONTINUING TAC BENEFIT AND OPERATIONS, PENSION, AND BENEFITS COST CONTROL

26. The Company has taken a number of steps to mitigate the proposed rate increases. First, the Company is proposing to flow back to customers significant tax benefits to replace expiration of the unprotected Excess Deferred Income Taxes ("EDIT") refunded to customers through the TAC as a result of the 2018 base rate case. Second, the Company has contained the growth of distribution-related O&M expenses, including electric and gas

[9] Schedules 1 and 2 to this Petition, listed below with all other Schedules, consist respectively of PSE&G's proposed electric tariff and a red-lined comparison of the proposed versus the present tariff. Schedules 3 and 4 are comparable tariff submissions for PSE&G's gas distribution service.

distribution operating costs, while reducing certain administrative and general ("A&G") costs, including pension and benefits. Third, PSE&G's cost of debt is relatively flat compared to the last rate case despite the significant recent increase in interest rates. Finally, the Company's Appliance Service Business has grown its net margins (revenues less expenses), which reduces the revenue request in this proceeding. These efforts have enabled the Company to reduce the rate request that it otherwise would have made, and each is described below.

Flow-Back of Tax Benefits Through the TAC

27. As detailed in the testimonies of PSE&G witnesses Mr. Michael McFadden, Mr. Clifford Pardo, and Mr. Swetz, the TAC is a mechanism approved in PSE&G's 2018 base rate case to refund certain tax benefits to customers. Mr. Pardo describes the various elements of the total available tax benefits that have been and are being passed back to customers. In this proceeding, PSE&G also proposes to flow back to customers benefits associated with tax deductions for what is referred to as Mixed Service costs, which are not subject to IRS normalization rules, resulting in a significant benefit to customers.

28. PSE&G also proposes changes to the TAC that will provide greater consistency in the flow-back to avoid rate swings as well as potentially mitigate future increases to customers when the amortization is complete and adjust the allocation of the TAC among customer classes so that for gas customers, all of the refund is attributed to firm customers. These changes are summarized in the testimony of Mr. McFadden; details on the TAC components are provided in the testimony of Mr. Pardo; and details on the calculation of the TAC, proposed rates, and bill impacts are provided in the testimony of Mr. Swetz.

Electric and Gas Distribution Operating Costs

29. PSE&G's successes in controlling its operating costs have mitigated the customer impacts of this base rate request. These cost control efforts have helped to offset increases in distribution-related O&M costs due to inflation, including cost increases to satisfy regulatory requirements, and other cost increases since the Company's last rate case. In this proceeding PSE&G provides examples of how the Company seeks to manage these costs while obtaining strong operating results. PSE&G will provide details on cost containment in the area of wages, for example, where the Company has controlled distribution-related O&M growth by regularly assessing its compensation levels to keep them competitive with the market while providing appropriate incentives to employees to focus on key operational metrics and critical business initiatives. This filing also discusses the Company's Voluntary Exit Incentive Program ("VEIP"), initiated in 2022 for non-represented employees, which is resulting in significant savings.

Pension and Benefits Costs

30. PSE&G's success in controlling pension costs is noteworthy as it has translated into a proposed revenue requirement reduction for Pension and Other Post-Employment Benefits ("P&OPEB") income of approximately $9 million. In this proceeding PSE&G will detail the steps it has taken to control pension costs. For example, this filing details how effective management of the returns on PSE&G's pension funds has lowered expenses, with annualized long-term returns that exceed the industry median. Additional steps taken to reduce the costs of the plan over prior decades include transitioning from a Final Average Pay Plan

("FAPP") to a cash balance pension plan and modifying the FAPP to consider the last seven years instead of the last five years for benefit purposes, materially reducing pension costs.

31. As a result of effective management, as well as present market conditions and other factors, P&OPEB is *reducing* the Company's request in this proceeding by approximately $9 million. In this proceeding PSE&G will explain why, considering the nature of this income, it would be appropriate to include the net pension asset as a component of working capital, as the Company does not have access to the cash associated with this income. If a working capital adjustment is not allowed, the pension income should be set to zero.

32. Finally, the Company is proposing that any difference between the P&OPEB income amount credited to customers in this proceeding and actual results for the utility be deferred for recovery or refund in a future rate case proceeding. Due to the size of PSE&G's pension asset, the Company's annual pension income is subject to meaningful volatility due to changes in the markets. In February 2023, the BPU approved a change in the Company's pension accounting that allowed for a five-year smoothing of the actuarial gains/(losses) associated with pension asset performance, which reduced the Company's pension expense in 2023 and 2024, lowering the Company's revenue request in this proceeding. The Pension Smoothing Order does help reduce volatility, but significant volatility in annual pension costs remains. The proposed mechanism would protect customers and the Company from significant swings in the pension income from short-term market fluctuations.

Appliance Service Business

33. PSE&G is the only utility in the State that continues to have an Appliance Service Business ("ASB") within the utility. Much of the pre-tax earnings of this business are

captured in the revenue requirement-setting process of each PSE&G base rate case, including this one. The Company is proposing in this proceeding to equalize retention of the gas ASB margins in the same manner as allowed for an electric utility under the New Jersey Administrative Code, as well as the sharing methodology for gains and losses on sales of land. Even with the Company's proposal, ASB would represent a significant benefit to electric and gas customers of approximately $46 million of margin (revenue less expenses) that will offset PSE&G's revenue requirement and is comparable to the margin returned to customers in the last base rate case.

Interest Cost Containment

34. Despite headwinds due to the inflationary environment, the Company has maintained the embedded cost of debt relatively comparable to the substantially reduced level set in the 2018 rate case. This result is primarily due to issuing long-dated debt during the historically low interest rate environment experienced over the past decade, strong PSE&G credit ratings, and solid execution of PSE&G's financing plan. Despite the Company's best efforts to contain the embedded cost of debt, the outlook for interest rates is expected to be higher for some time – and certainly during the first year when rates set in this case will go into effect – due to a variety of market factors. As a result, the Company is proposing an interest rate adjustment mechanism to defer the impact of changes in the Company's actual embedded cost of debt on the debt portion of its approved rate base in this proceeding as described in the testimony of Mr. McFadden.

VI. CAPITAL STRUCTURE AND THE COST OF CAPITAL

35. PSE&G proposes that the Company's overall Return on Equity ("ROE") should be set at 10.4%, reflecting current market and business conditions, PSE&G's consistently top level operating performance. The basis for this request is outlined in Mr. McFadden's testimony, and detailed support is provided in the testimony of Ms. Ann Bulkley of The Brattle Group and Mr. Michael Adams of Concentric Energy Advisors, Inc. PSE&G proposes to apply its ROE to a capital structure reflecting a common equity component of 55.5%, to realize targeted credit statistics and maintain a strong investment grade rating. While PSE&G was approved at a 54% common equity percentage in its 2018 base rate case, it has been maintaining a common equity percentage above 55% in recent years to support its credit rating. PSE&G is seeking an overall rate of return of 7.55% that is derived from a capital structure composed of 55.5% equity, 44.29% long-term debt, and 0.21% customer deposits. The embedded cost rate for the Company's long-term debt is estimated to be 4.02% by the end of the test year. Customer deposits are accumulated at a rate of 1.40% as of January 1, 2023. The proposed ROE is 10.4%, as discussed in Ms. Bulkley's testimony, and is also supported by Mr. Adams's testimony benchmarking PSE&G's performance across numerous metrics with that of its peers nationally as well as in New Jersey.

36. Ms. Bulkley considers numerous factors to support her conclusion. Ms. Bulkley observes that as the yields rise on risk-free investments - - such as U.S. Treasury bonds - - utility stocks can become less desirable as the premium needed to take on the additional risk declines, supporting an increase in utility ROE. Additionally, the Federal Funds

Rate and inflation rate are higher than during the Company's last base rate case, indicating more risk to investors, who will demand higher equity returns.

37. In addition to Ms. Bulkley's model-based testimony, Mr. McFadden testifies that clear state policy, supported by numerous legal requirements, dictates a significant expansion of electric vehicle adoption, increasing solar targets, and expanded electrification, and those same policy discussions have raised significant questions about the future of the natural gas business. PSE&G supports the State's goals, and they can present opportunities for growth for the Company. However, it also represents uncertainty and risk to investors. Electric business growth opportunities will involve significant capital investment to ensure the reliability of the distribution system as customers depend on it more than ever. The capital requirements of this transition, along with the uncertainties impacting PSE&G's businesses, particularly in the current inflationary and higher interest rate environment, strongly suggest that the electric and gas businesses are subject to meaningfully higher risk during the on-going energy transition than they were when PSE&G's cost of equity was established in 2018.

38. The Company's capital structure request also is supported by PSE&G's history of sound financial management and strong credit metrics, as described in the testimony of Mr. McFadden.

VII. PENSION COST RECOVERY

39. The Company's annual pension income is subject to meaningful volatility due to changes in the markets, which has a material impact on rates due to the size of PSE&G's pension asset. In February 2023 the Board authorized PSE&G to modify its pension accounting practices in a manner that would reduce the volatility of only one component of

the Company's annual pension expenses impacted by market fluctuations.[10] However, market volatility can still significantly impact other pension cost components including the expected return on assets component.

40. PSE&G is proposing that any volatility in the P&OPEB income (or expense) above or below the amount set for recovery in this proceeding be deferred for recovery or refund in a subsequent rate case proceeding.

41. The proposal would defer any variances between the required actuarial expense/income recorded on the FERC income statements and the amount refunded to customers as a result of this proceeding. This would ensure neither the customers nor the Company would win or lose based on market fluctuations outside of the amount refunded to customers in this case.

VIII. APPLIANCE SERVICE BUSINESS

42. PSE&G is the only utility in the State that continues to have an appliance service business ("ASB") within the utility structure. The margins produced by the ASB are used directly for the benefit of PSE&G's customers, reducing their cost of service. As a result of this structure, the majority of pre-tax margins of this business have been captured in the revenue requirement-setting process of PSE&G's base rate cases.

43. In addition to these direct, annual financial benefits through ratemaking, maintaining ASB in the utility also enables operational benefits to the utility, benefiting

[10] *I/M/O Public Service Electric and Gas Company's Request for an Accounting Order Authorizing the Company to Modify Its Pension Accounting for Ratemaking Purposes*, BPU Docket No. ER22090549, Decision and Order Approving Stipulation (February 17, 2023). The only component of pension expense addressed in that Order was the amortization of net gains and losses.

customers. Appliance service technicians are skilled labor that also perform emergency response duties as well as meter services, such as meter installations and replacements, and turn-on and shutoff services. If not for ASB, PSE&G would need to hire additional personnel to be available for emergency response that would not have work during non-peak periods, which would result in a material increase in costs to customers.

44. Notwithstanding these benefits, continuation of ASB presents business challenges, including declining numbers of customers purchasing Contract services, which is a significant element of ASB's business. The business also faces challenges in the supply chain, leading to cost increases and part shortages. Price increases can be a short-term fix but over the longer term, continual increases will hasten the decline in the number of customers, and they take at least a year to implement once contracts expire, creating more risk to retaining the current margin.

45. These issues are amplified by the practice, followed for ratemaking purposes pursuant to *N.J.A.C.* 14:4-3.6(r), which has 50% of Electric margins and 100% of Gas margins in the test year returned to customers. PSE&G is proposing to retain 50% of the total net margins from the provision of ASB services to its gas customers in the same manner as allowed for its electric customers. The basis for and benefits of this approach are detailed in Mr. McFadden's testimony.

46. PSE&G is proud of its ASB business, its skilled workforce, and the value that it generates for customers, through the financial benefits summarized above and detailed by Mr. McFadden, and through the important services and efficiencies it provides as discussed in the panel testimony of Mr. Schmid and Mr. Fonseca. However, if there is more risk than

reward potential associated with this business, as the Company believes there is under the existing, inequitable margin-sharing arrangement between electric and gas, PSE&G will consider restructuring or discontinuing this business in its current form.

IX. GAS BAD DEBT EXPENSE RECOVERY THROUGH THE SOCIETAL BENEFITS CHARGE ("SBC")

47. As PSE&G previously proposed in the COVID-19 proceeding,[11] PSE&G reiterates here its proposal to recover gas bad debt expenses through a new Social Programs component of the SBC, consistent with the recovery of electric bad debt expense.

48. Gas uncollectible expenses are currently recovered in base rates, and there is no true-up between the actual gas bad debt expense incurred and the recovery through base rates (and the TAC). It would be more appropriate for PSE&G to recover gas bad debt expenses through the SBC, as is done for the electric business. Recovery of gas bad debt expense through the SBC will ensure recovery of an accurate amount, with neither the Company nor its customers subject to under- or over-recovery or charge. This approach, which has worked well for electric bad debt for decades, also provides for periodic prudence review of the utility's bad debt cost.

[11] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (filed July 17, 2023). This issue remains pending in the COVID-19 proceeding docket.

X. STORM COST RECOVERY – DEFERRED ACCOUNTING, ADJUSTMENT FOR EXPIRING AMORTIZATION, AND PROPOSED STORM COST RECOVERY MECHANISM

49. PSE&G has incurred significant incremental O&M expense for preparation and/or restoration efforts associated with five major storm events from July 2018 through the date of this filing. As it has done since 2010, the Company defers these costs for future recovery in a manner to be determined by the BPU. Following a *pro forma* adjustment to test year expense in PSE&G's 2018 base rate case, there is no base rate recovery of incremental O&M for post 2018 major storm events in the Company's current base rates.

50. In this case PSE&G proposes to continue the use of deferred accounting for incremental Major Storm Event costs, which ensures that customers will pay no more and no less than the Company's actual costs associated with events that are beyond the Company's control and impossible to predict. The Company should not profit from the absence of Major Storm Events, nor should it be penalized for prudently incurred incremental expenses associated with Major Storm Events.

51. PSE&G proposes to create a new clause, "the Storm Recovery Charge," to recover the $109 million in deferred storm costs incurred since the last rate case as well as any future prudently incurred storm costs. This will both ensure that customers pay only for actual, prudently incurred costs, and protect the Company from significant financial harm from major weather events outside of its control. Use of a clause for Major Storm Event cost recovery would also allow for more timely prudence review than the current method, benefit the Company's credit ratings (which benefits customers), mitigate rate shock, and provide a mechanism to stop the amortization when recovery of the deferral is completed.

52. Finally, PSE&G proposes that this clause permit recovery of mobilization, or "pre-staging" costs for predicted major storms that do not come to pass, in excess of a certain minimum cost level. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prudently prepare for future storms.

XI. CLEAN ENERGY FUTURE – ELECTRIC VEHICLE ("CEF-EV") COST RECOVERY AND RATE ADJUSTMENT TEMPLATE

Cost Recovery For CEF-EV Investments in Service

53. In its CEF-EV Order, the Board authorized PSE&G to invest up to $166.2 million in facilities associated with its CEF-EV programs and to incur up to $39 million of incremental O&M expenses, including administrative costs, to support the program. Those CEF-EV programs consist of the following three subprograms that provide incentives for EV charger installation: (i) a Residential Smart Charging program; (ii) a Level 2 Mixed Use Commercial Charging program; and (iii) a Public Direct Current ("DC") Fast Charging program. The CEF-EV Order also permitted the Company to establish two regulatory assets that allowed it to defer for recovery in this rate case the capital and O&M costs of the CEF-EV program.

54. Following the issuance of the CEF-EV Order, PSE&G undertook and completed program development, including development of the Information Technology architecture necessary to administer the program. PSE&G then launched the CEF-EV Program in a series of steps from June through September 2021, that included opening program enrollment applications, issuing demand charge rebates, and marketing and customer education activities.

55. As described in the testimony of Company witness Ms. Karen Reif, PSE&G's CEF-EV program has been very successful. Enrollment in each program has exceeded expected enrollment levels, reflecting PSE&G's successful marketing, education, and outreach. PSE&G has also administered the program on a "first come, first served" basis to encourage early participation and to eliminate the risk of bias or favoritism. PSE&G has required all customers or EV stations receiving an incentive to be "networked," and PSE&G has worked with numerous stakeholders to collect charging data to inform future programs. Finally, the Company has been cognizant of the need to offset costs, providing information about other publicly funded incentive programs, and regularly benchmarking costs of similar services in other utility-led EV programs.

56. PSE&G requests a prudency determination and recovery of CEF-EV investments and expenditures that the Company proposes to include in rates in this proceeding. The regulatory asset balances for CEF-EV capital and O&M costs have been established in accordance with the CEF-EV Order.

57. Finally, in accordance with the CEF-EV Order, PSE&G seeks approval of the Company's methodology for future rate adjustments for CEF-EV investments that are incurred after this rate case. This issue as well as the Company's proposed recovery methodology and timing of future rate adjustments are further discussed in the testimony of Mr. Swetz.

XII. AMI COST RECOVERY

58. In its January 2021 CEF-EC Order, the Board authorized the Company to install approximately 2.2 million Advanced Meter Infrastructure ("AMI") meters and an associated communication network, and to implement 22 AMI functionalities known as "Use Cases." The

CEF-EC Order permitted the Company to seek, in this base rate case, recovery of both the CEF-EC costs that the Company proposes to include in rates and the regulatory asset balances of CEF-EC Infrastructure Deferral, Stranded Cost Deferral, and Operation and Maintenance ("O&M") regulatory assets.

59. As described in the testimony of Company witness Mr. David Johnson, the Company began installing AMI meters during 2021 and 2022 and accelerated installations in 2023. The program is currently ahead of schedule and under budget, and PSE&G projects complete installation within six months of the end of the test year.

60. Numerous customer benefits already have been realized. Billing on actual usage transmitted by the AMI meters, instead of manual reads, is achieved after a three-day verification period following installation of each AMI meter. Additionally, remote move in/move out, and remote connect/disconnect functionalities are enabled and are being used via installed AMI meters.

61. The CEF-EC order committed PSE&G to use "best efforts" to implement 22 out of a total of 70 Use Cases. Several Use Cases already have been implemented, and the current schedule reflects that all 22 Use Cases, including Outage Detection & Analysis, will be deployed by the end of the second quarter of 2024.

62. PSE&G therefore requests a prudency determination and recovery of CEF-EC costs, and the associated regulatory asset balances.

XIII. EMBEDDED COST OF DEBT RATE RECOVERY

63. Currently, interest expense is recovered as the Company's electric and gas rate base multiplied by the long-term debt component of its capital structure and then by the embedded cost of long-term debt, and each component will be approved in this rate case.

64. PSE&G's long-term debt outstanding has grown significantly since the last rate case, and PSE&G expects the materiality of interest expense will continue to increase as debt grows to finance PSE&G's capital investment program needed to meet the State's clean energy targets and maintain safe and reliable service. In addition to financing new capital investments, approximately $1.1 billion of the existing long-term debt will come due in 2024 and 2025.

65. Recent history, however, has demonstrated that there can be significant movements in interest rates. The current interest rate environment and the need to refinance existing debt after the end of the test year will likely result in the Company's interest expense exceeding its revenue recovery within the first year that new rates go into effect.

66. To account for these conditions, PSE&G proposes a new interest cost reconciliation mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding. As described in the testimony of Mr. McFadden, this mechanism will avoid the need for a *pro forma* adjustment that would increase costs to customers in this proceeding and will provide the Company an opportunity to earn its allowed return. The mechanism would also ensure the Company recovers no more or less than its allowed interest expense and can be reevaluated in a future base rate case.

67. The deferral mechanism would apply only to the debt component of rate base approved by the Board. It would also operate symmetrically and allow for potential refunds to

customers when interest rates decline and the embedded cost of debt declines below the amount approved for rate recovery.

68. Finally, PSE&G proposes that for the Company's future infrastructure investment program ("IIP") rate adjustment filings, such as GSMP II Extension and IAP, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding. In addition, the Weighted Average Cost of Capital ("WACC") in the Company's Green Program Recovery Charge ("GPRC") and TAC should be updated monthly, consistent with the monthly return calculation for each program with a return component.

XIV. CONSERVATION INCENTIVE PROGRAM ("CIP")

69. Historically, the State's electric and gas utilities were incented to increase sales volumes, as increasing sales volume increases revenues and therefore earnings. That incentive, however, is directly contrary to State policy to reduce usage, expressly set forth in the State's Energy Master Plan, which in turn reduces overall emissions and customer bills.

70. On September 23, 2020, the Board approved a stipulation resolving all matters associated with PSE&G's Clean Energy Future – Energy Efficiency ("CEF-EE") petition, which included approval of the CIP mechanism.[12] This mechanism provides a rate adjustment related to changes in the average use per customer when compared to a baseline use (and for electric, demand) per customer, removing the Company's disincentive to encourage customers

[12] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis*, BPU Docket Nos. GO18101112 and EO10121113, Order Adopting Stipulation (September 23, 2020).

to conserve energy that existed historically. The current baselines per customer are based on the approved billing determinants from the Company's 2018 base rate case.

71. PSE&G proposes two adjustments that must be made in a base rate case proceeding associated with the CIP. First, the Company establishes new baseline use (gas) or revenue (electric) per-customer figures that will go into effect upon approval of this proceeding. Second, a *pro forma* adjustment must be made to the test year income statement to remove the CIP accrual to account for the reset of the CIP baseline. As a result of these two adjustments, base rates and the CIP accrual baseline use (gas) or revenue (electric) per customer will be based on the approved billing determinants for this test year of June 1, 2023 through May 31, 2024. Therefore, PSE&G is requesting the establishment of new Electric and Gas baselines that will go into effect upon approval of this proceeding.

XV. DEPRECIATION

72. PSE&G presents a detailed evaluation of the Company's assets and new depreciation rates based on that evaluation. Properly set depreciation rates allow the Company to recover its investments timely, charge those costs to the customers who benefited from their use, and fund new capital construction. Company witness Mr. John Spanos has conducted a detailed evaluation of PSE&G's assets, and applied it to develop new depreciation rates to recover the costs of replacing aging infrastructure over its useful life and account for the cost to remove assets in the future. Consistent with *N.J.A.C.* 14:1-5.7, the Company's existing and proposed depreciation rates are included with this filing and set forth in the testimony of Mr. John Spanos.

XVI. INCENTIVE COMPENSATION

73. PSE&G maintains a compensation structure designed to attract and retain a talented and diverse workforce to operate safely, reliably, and cost-effectively. The Company's compensation structure (salary ranges, incentive compensation targets, and related factors) is regularly benchmarked and is aligned with industry standards to enable the Company to attract and retain its management team and overall workforce.

74. PSE&G's test year expenses in this case include approximately $36 million associated with incentive compensation. Similar to industry peers and the vast majority of companies, PSE&G has implemented a compensation program that is composed of a mix of fixed base pay and incentive pay. The incentive compensation is dependent upon achieving goals that are primarily operational and customer focused, with metrics focused on Reliability (*e.g.*, SAIDI, gas leaks per mile, damages per locate requests), Customer Satisfaction (J.D. Power scores and other metrics), and other operational metrics.

75. For a variety of reasons, including the operational and customer-focused goals underlying the program, PSE&G's incentive compensation is a prudent cost, and therefore PSE&G is seeking to recover its $36 million incentive compensation expense in this proceeding.

XVII. DEFERRAL REQUESTS – CREDIT AND DEBIT CARD FEES AND IMPLEMENTATION COSTS FOR TIME OF USE RATES

76. PSE&G requests deferral authority for two costs that will occur outside the test year.

Credit and Debit Card Fees

77. Currently, credit card and debit card processing fees are not allowed to be recovered through rates, while all other payment transaction fees are allowed recovery. Credit card and debit card processing fees are instead charged as a pass-through fee to customers at the time of payment.

78. As discussed in the testimony of Mr. McFadden, the Company proposes removing this disparity for customers, by assuming the cost for credit and debit card transactions rather than requiring the payment from individuals using a credit or debit card.

79. Since it is unknown at this time how many customers will pay via credit card once the transaction fee is removed, the Company is proposing to defer those incremental expenses until the next base rate case.

Implementation Costs for Time-of-Use Rates

80. As discussed in the Direct Testimonies of Mr. Swetz and Company witness Mr. Ahmad Faruqui, the Company is proposing a Residential Time-of-Use ("TOU") Rate that encourages customers, especially EV users, to shift their usage to off-peak periods. To encourage participation, PSE&G proposes that during the first year of the enrollment, PSE&G would refund the difference to customers if the TOU rate yields a bill higher than the customer

otherwise would have been charged on their current residential rate. This hold harmless provision will be offered to customers enrolling within the first 24 months of the program.

81. Implementing TOU rates and the ability to compare those rates to existing residential rates and issue a refund will require significant changes to the existing billing system, resulting in incremental capital and O&M costs. The Company seeks approval to defer these costs and to place them in a regulatory asset for review and recovery in the Company's next base rate case.

XVIII. TESTIMONY AND EXHIBITS INCORPORATED HEREIN

82. To support this case, the Company is presenting the Direct Testimony of eleven witnesses:

Exhibit	**Witness**	**Area of Responsibility**
Exhibit P-2	Michael McFadden, Director, Sales and Revenue Forecasting	Overall financial policy and revenue requirements
Exhibit P-3	Panel Testimony -- Michael Schmid, Vice President, Asset Management and Planning, PSE&G and Ricardo G. Fonseca, Senior Director, Utility Finance	Electric and gas operations, capital expenditures, and electric and gas distribution-related O&M expense
Exhibit P-4	Clifford Pardo, Vice President – Tax PSEG Services Company	Tax expense, accumulated deferred income tax and tax benefit flow-back; Consolidated Tax Adjustment
Exhibit P-5	Ann E. Bulkley, The Brattle Group	Return on equity, capital structure, financial environment
Exhibit P-6	Michael Adams, Concentric Energy Advisors	Benchmarking of PSE&G's financial and operational performance
Exhibit P-7	John J. Spanos, Gannett Fleming	Depreciation
Exhibit P-8	Michael Adams, Concentric Energy Advisors	Lead/lag study, cash working capital

Exhibit P-9E, Exhibit P-9G	Stephen Swetz, Senior Director – Rate and Regulation, PSE&G	Cost of service, rate design, and tariff submissions
Exhibit P-10	Ahmad Faruqui, Principal Emeritus, The Brattle Group	Time-of-Use Rates
Exhibit P-11	Karen Reif, Vice President Renewables & Energy Solutions	CEF-EV implementation
Exhibit P-12	David Johnson, Vice President Customer Care & Chief Customer Officer PSE&G	Advanced Metering Infrastructure, CEF-EC implementation

83. Information required by the Rules of Practice of the Board, (*N.J.A.C.* 14:1-5.12), is attached hereto, made part hereof and designated as follows:

Table of Schedules

Schedule 1 - Proposed Tariff for Electric Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 17, Electric

Schedule 2 - Comparison of Present and Proposed Electric Rates, using redlined Schedule 1 and Guide to Tariff Changes

Schedule 3 - Proposed Tariff for Gas Service, Public Service Electric and Gas Company, B.P.U.N.J. No 17, Gas

Schedule 4 - Comparison of Present and Proposed Gas Rates, using redlined Schedule 3 and Guide to Tariff Changes

Schedule 5 - Copy of billing notice to be mailed to all electric and gas customers

Schedule 6 - Copy of draft text for legal notice in the public press

Schedule 7 - Copy of letter to notice all county and municipal clerks of counties and municipalities served by Public Service

Schedule 8 - Balance Sheet at the most recent date available as of October 31, 2023, and Balance Sheets for the calendar years 2020, 2021, and 2022

Schedule 9 - Statement of Income Account for the calendar years 2020, 2021 and 2022

Schedule 10 - Statement of Operating Revenues for calendar year 2022

Schedule 11 - *Pro forma* statements for the 12-month period ended May 31, 2024 on an estimated basis as follows:

Income Account
Sales by Class of Business
Operating Revenues by Class of Business
Operating Expenses
Adjustments – Present Rates
Pro Forma Statement of Income
Year-end Net Investment Rate Base
Average Net Investment Rate Base

Schedule 12 - Schedule of Payments or Accruals to Affiliates for calendar year 2022.

XIX. MISCELLANEOUS

84. Petitioner, pursuant to *N.J.A.C.* 14:1-5.12, will provide notice of the filing of this petition to all of its customers as part of the regular monthly service billing. A sample copy of the billing notice is attached and designated as Schedule 5.

85. Petitioner's customers will also be notified of this Petition through the medium of a legal notice in the public press. A copy of the draft text of the aforesaid legal notice is attached hereto, made part hereof and designated as Schedule 6.

86. The municipalities and counties served by Petitioner, as enumerated in Schedules 1 and 3, will be notified of the filing of this Petition pursuant to *N.J.A.C.* 14:1-5.12 by letter, a copy of which is attached hereto, made part hereof and designated as Schedule 7.

87. Notice of this filing and the Petition will be served electronically upon the Department of Law and Public Safety, and upon the Director, New Jersey Division of Rate

Counsel. Copies of the Petition and supporting testimony and attachments will also be sent via e-mail to the persons identified on the service list provided with this filing.

88. It is understood that any final rate relief found by the Board to be just and reasonable may be allocated by the Board for consistency with the provisions of *N.J.S.A.* 48:2-21 and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the percentage changes in final electric and/or gas rates may increase or decrease based upon the Board's decision.

89. Communications and correspondence related to this Petition should be sent as follows:

Joseph F. Accardo Jr.
Vice President - Regulatory & Deputy General Counsel
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (973) 430-5811
E-Mail: joseph.accardo@pseg.com

Katherine E. Smith
Managing Counsel - State Regulatory
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (973) 430-7052
E-Mail: katherine.smith@pseg.com

Matthew M. Weissman
Special Counsel, State Regulatory
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (973) 430-7052
E-Mail: matthew.weissman@pseg.com

Danielle Lopez
Associate Counsel - Regulatory
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (973) 430-6479
E-Mail: Danielle.Lopez@pseg.com

Aaron I. Karp
Associate Counsel - Regulatory
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (973) 430-8970
E-Mail: aaron.karp@pseg.com

Stacey M. Mickles
Associate Counsel - Regulatory
PSEG Services Company
80 Park Plaza, T10
Newark, New Jersey 07102
Telephone No. (856) 516-7934
E-Mail: stacey.mickles@pseg.com

Please provide an additional electronic copy to: caitlyn.white@pseg.com and bernard.smalls@pseg.com.

WHEREFORE, Petitioner requests that the Board find and determine that pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1:

1. The present rates and charges for electric service set forth in the present Tariff for Electric Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 16, Electric, on file with the Board, are unjust and unreasonable and are insufficient to permit the Company to maintain its financial integrity and provide safe, adequate, proper, and reliable electric service to its customers pursuant to *N.J.S.A*. 48:2-23.

2. The present rates and charges for gas service set forth in the present Tariff for Gas Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 16, Gas, on file with the Board, are unjust and unreasonable and are insufficient to permit the Company to maintain its financial integrity and provide safe, adequate, proper, and reliable gas service to its customers pursuant to *N.J.S.A*. 48:2-23.

3. The proposed rates and charges for electric service, set forth in the proposed tariff for Electric Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 17, Electric, reflected in Schedule 1, will provide electric distribution operating revenues sufficient to meet operating expenses, taxes and fixed charges and provide a reasonable rate of return on the fair value of the Petitioner's electric property.

4. The proposed rates and charges for gas service, set forth in the proposed tariff for Gas Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 17, Gas, reflected in Schedule 3, will provide gas distribution operating revenues sufficient to meet operating expenses,

taxes and fixed charges and provide a reasonable rate of return on the fair value of the Petitioner's gas property.

5. The proposed rates and charges for electric distribution service set forth in the proposed Tariff for Electric Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 17 Electric, referred to herein as Schedule 1, are approved as just and reasonable.

6. The proposed rates and charges for gas distribution service set forth in the proposed Tariff for Gas Service, Public Service Electric and Gas Company, B.P.U.N.J. No. 17 Gas, referred to herein as Schedule 3, are approved as just and reasonable.

7. Investments in the Mason Station, GSMP II, Energy Strong II, and CEF-EC programs, including any associated regulatory assets, were reasonable and prudent and eligible for final rate recovery.

8. The CEF-EV investments and expenditures are prudent and eligible for rate recovery.

9. The recovery of the investments in the Energy Strong II, GSMP II, and IAP programs that are not subject to interim recovery ("Stipulated Base") is approved.

10. The adjustment to flow-back certain tax benefits to customers through the TAC is approved.

11. The proposal to either include PSE&G's net pension asset as a component of working capital, or, if a working capital adjustment is not allowed, the pension income should be set to zero, is approved.

12. The proposal that any volatility in the P&OPEB income (or expense) above or below the amount set for recovery in this proceeding be deferred for recovery or refund in a subsequent rate case proceeding is approved.

13. The proposal to retain 50% of the total net margins from the provision of ASB services to its gas customers in the same manner as allowed for its electric customers is approved.

14. The Company's overall ROE be set at 10.4%.

15. A capital structure composed of 55.5% equity, 44.29% long-term debt, and 0.21% customer deposits is approved.

16. The proposal to recover gas bad debt expense through a new component of the SBC is approved.

17. The proposal to continue the use of deferred accounting for incremental Major Storm Event costs, and to recover storm costs, including pre-staging costs for predicted major storms that do not come to pass, through a new clause component rather than through base rates is approved.

18. The proposed methodology and timing for the recovery of CEF-EV costs incurred subsequent to this rate case is approved.

19. The proposal for a new interest cost reconciliation mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding is approved.

20. The proposal that for the Company's future IIP rate adjustment filings, the embedded cost of long-term debt should be the actual rate at the time the Company submits its

update for actual results in the associated proceeding and would be adjusted monthly in the Company's GPRC and TAC is approved.

21. The proposed depreciation rates set forth in the testimony of Mr. John Spanos, attached hereto as Exhibit P-7, are approved.

22. The proposal to assume the cost of credit and debit card transactions and defer those incremental expenses until the next base rate case is approved.

23. The costs of implementing the TOU rates described herein are deferred until the next base rate case is approved.

24. The proposed tariff changes are approved as just and reasonable, and may become effective on the date proposed herein.

25. Petitioner be granted such other and further relief as the Board may deem reasonable and proper.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By _____
Katherine E. Smith

DATED: December 29, 2023
Newark, New Jersey

STATE OF NEW JERSEY)
: ss
COUNTY OF ESSEX)

KATHERINE E. SMITH, of full age, being duly sworn according to law, on his oath deposes and says:

1. I am Managing Counsel of the New Jersey State Regulatory Legal Group of PSEG Services Company.

2. In my role I represent Public Service Electric and Gas Company, the Petitioner in the foregoing Petition.

3. I have read the annexed Petition, and the matters and things contained therein are true to the best of my knowledge and belief.

Katherine E. Smith

Sworn to and subscribed to)
Before me this 29th day)
of December, 2023)

CAITLYN M. WHITE
NOTARY PUBLIC OF NEW JERSEY
My Commission Expires 9/19/2024

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 1**

TARIFF

FOR

ELECTRIC SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 4 through 7 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 2**

TABLE OF CONTENTS

Title Page ..... Sheet No. 1
Table of Contents ..... Sheet Nos. 2 and 3
Territory Served ..... Sheet Nos. 4 to 7, inclusive
Standard Terms and Conditions ..... Sheet Nos. 8 to 42, inclusive
Regulation for Residential Underground Extensions ..... Sheet Nos. 48 to 52, inclusive
Societal Benefits Charge ..... Sheet Nos. 57 to 58, inclusive
Non-utility Generation Charge ..... Sheet No. 60
Zero Emission Certificate Recovery Charge ..... Sheet No. 61
Solar Pilot Recovery Charge ..... Sheet No. 64
Green Programs Recovery Charge ..... Sheet No. 65
Conservation Incentive Program ..... Sheet Nos. 66 to 66D, inclusive
Distribution Adjustment Charge ..... Sheet No. 67
Tax Adjustment Credit ..... Sheet No. 69
Infrastructure Improvement Program Charges ..... Sheet Nos. 70 to 72, inclusive
Commercial and Industrial Energy Pricing (CIEP) Standby Fee ..... Sheet No. 73
Basic Generation Service

- Residential Small Commercial Pricing Electric Supply Charges
  - BGS Energy & Capacity Charges ..... Sheet Nos. 75 and 76
  - BGS Transmission and Energy Charges ..... Sheet No. 76
  - BGS Capacity Charges and Transmission Charges ..... Sheet No. 79
  - BGS Reconciliation Charges ..... Sheet No. 81
- Commercial And Industrial Energy Pricing Electric Supply Charges
  - BGS Energy Charges, Capacity Charges and Transmission Charges ..... Sheet Nos. 82 and 83
  - BGS Reconciliation Charges ..... Sheet No. 84

Third Party Supplier ..... Sheet No. 87

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 3**

TABLE OF CONTENTS
(Continued)

Rate Schedules and Payment Schedule as listed below:

	Rate Schedule	Sheet No.
Residential Service	RS	93-98
Residential Heating Service	RHS	99-102
Residential Load Management Service	RLM	105-108
Water Heating Service	WH	111-114
Water Heating Storage Service	WHS	117-120
Building Heating Service	HS	123-126
General Lighting And Power Service	GLP	129-141
Large Power And Lighting Service	LPL	142-154
High Tension Service	HTS	155-165

Other Services:

Payment Schedule – Purchased Electric Power	PEP	176-177
Body Politic Lighting Service	BPL	179-191
Body Politic Lighting Service From Publicly Owned Facilities	BPL-POF	195-200
Private Street and Area Lighting Service	PSAL	203-214

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 4**

TERRITORY SERVED

BERGEN COUNTY

Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Maywood, Borough of
Midland Park, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of
Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Medford Lakes, Borough of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
Palmyra, Borough of
Pemberton, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westamptown, Township of
Willingboro, Township of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Gloucester, Township of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Hi-Nella , Borough of
Lawnside, Borough of
Magnolia, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Runnemede, Borough of
Somerdale, Borough
Tavistock, Borough of
Voorhees, Township of
Wood-Lynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
Washington, Township of
West Deptford, Township of
Westville, Borough of
Woodbury, City of
Woodbury Heights, Borough of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

HUDSON COUNTY (continued)

Union City, City of
Weehawken, Township of
West New York, Town of

MERCER COUNTY

Ewing, Township of
Hamilton, Township of
Hopewell, Borough of
Hopewell, Township of
Lawrence, Township of
Pennington, Borough of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Carteret, Borough of
Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Highland Park, Borough of
Metuchen, Borough of
Middlesex, Borough of
New Brunswick, City of
North Brunswick, Township of
Perth Amboy, City of
Piscataway, Township of
Plainsboro, Township of
South Brunswick, Township of
South Plainfield, Borough of
Woodbridge, Township of

MONMOUTH COUNTY

Allentown, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Lincoln Park, Borough of

PASSAIC COUNTY

Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Prospect Park, Borough of
Totowa, Borough of
Wayne, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 7**

TERRITORY SERVED
(Continued)

UNION COUNTY

Clark, Township of
Cranford, Township of
Elizabeth, City of
Fanwood, Borough of
Garwood, Borough of
Hillside, Township of
Kenilworth, Borough of
Linden, City of
Mountainside, Borough of
Plainfield, City of
Rahway, City of
Roselle, Borough of
Roselle Park, Borough of
Scotch Plains, Township of
Union, Township of
Westfield, Town of
Winfield, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX

		Sheet No.
1.	**General**	**10**
2.	**Obtaining Service**	**10**
	2.1. Application	10
	2.2. Initial Selection of Rate Schedule	10
	2.3. Deposit and Guarantee	11
	2.4. Permits	12
	2.5. Selection of Lighting Options	12
3.	**Charges For Service**	**12**
	3.1. General	12
	3.2. Definitions	12
	3.3. Removal of Public Service Facilities	13
	3.4. Temporary Service	13
	3.5. Provision of Service	14
	3.6. Extensions – General Provisions	15
	3.7. Charges for Extensions	15
	3.8. Charges for Increased Load	18
	Characteristics Of Service	**18**
4.	4.1. General	18
	4.2. Types of Service	19
	4.3. Losses	19
	Service Connections	**19**
5.	5.1. General	19
	5.2. Overhead Service	20
	5.3. Underground Service in Underground Zone	20
	5.4. Underground Service in Overhead Zone	20
	5.5. Change in Location of Existing Service Line	21
	Service Entrance Installations	**21**
6.	6.1. General	21
	6.2. Seals	21
	6.3. Secondary Distribution Service	21
	6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service	22
	Meters and Other Equipment	**22**
7.	7.1. General	22
	7.2. Other Devices	23
	7.3. Protection of Meters and Other Equipment	23
	7.4. Tampering	23
8.	**Customer's Installation**	**24**
	8.1. General	24
	8.2. Wiring	24
	8.3. Inspection and Acceptance	24
	8.4. Customer On-Site Generation	24
	8.5. Maintenance of Customer's Installation	25
	8.6. Electrical Equipment and Appliances	25
	8.7. Power Factor	25
	8.8. Liability for Customer's Installation	25
	8.9. Replacement of Customer Owned Equipment Due to System Upgrades	25
9.	**Meter Reading and Billing**	**25**
	9.1. Measurement of Electric Service	25
	9.2. Metering on Customer's Premises	26
	9.3. Testing of Meters	27
	9.4. Metering Options	27
	9.5. Billing Adjustments	30
	9.6. Meter Reading and Billing Period	30
	9.7. Proration of Monthly Charges	30
	9.8. Averaged Bills	30
	9.9. Budget Plan (Equal Payment Plan)	30
	9.10. Billing of Charges in Tariff	31
	9.11. Payment of Bills	31
	9.12. Late Payment Charge	31
	9.13. Returned Check Charge	32
	9.14. Field Collection Charge	32
10.	**Access To Customer's Premises**	**32**
11.	**Discontinuance Of Service**	**32**
	11.1. By Public Service	32
	11.2. At Customer's Request	34
12.	**Reconnection Charge**	**34**
13.	**Service Limitations**	**34**
	13.1. Continuity of Service	34
	13.2. Emergencies	34
	13.3. Unusual Conditions	35
14.	**Third Party Supplier**	**35**
	14.1. Third Party Supplier Electric Supply	35
	14.2. Initiation of Service	35
	14.3. Customer Billing Process	36
	14.4. Continuity of Service	37
	14.5. Interval Metering	37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

		Sheet No.
15.	**Net Metering Installations**	**38**
15.1.	General	38
15.2.	Size Limitations	38
15.3.	Installation Standards	38
15.4.	Initiation of Service	39
15.5.	Net Billing	39
15.6.	Billing Adjustments	40
15.7.	Budget Plan (Equal Payment Plan)	40
15.8.	Program Availability	40
16.	**New Jersey Authorized Taxes**	**40**
16.1.	New Jersey Sales and Use Tax	40
16.2.	New Jersey Corporation Business Tax	41
17.	**Termination, Change or Modification Of Provisions Of Tariff**	**42**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 10**

STANDARD TERMS & CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as a part of the Electric Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service," set forth the terms and conditions under which electric service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of electric service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution equipment located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit, or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, P.O. Box 350, Trenton, New Jersey, 08625-0350, 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. **Application:** An application for service may be made at any of the Customer Service Centers of Public Service in person, or by telephone, by the Company's website at www.pseg.com, or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of electric service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters, in accordance with N.J.A.C. 14:3-3.2(e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of electricity to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13, Service Limitations and Section 14, Third Party Supplier Service Provisions of these Standards Terms and Conditions.

2.2. **Initial Selection of Rate Schedule:** Public Service will assist in the selection of the available rate schedule, which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customer may, upon written notice to Public Service within three months after service is begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS

(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle. Deposits shall cease to bear interest upon discontinuance of service.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it, after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities, and shall become effective on January 1 of the following year.

Interest payments shall be made at least once during each 12-month period in which a deposit is held and Public Service shall offer the customer the option of credits on bills toward utility service rendered or to be rendered or a separate check, in accordance with N.J.A.C. 14:3-3.5(h).

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service, Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 12**

STANDARD TERMS AND CONDITIONS

(Continued)

2.4. Permits: Public Service, where necessary, will make application for any street opening permits for installing its service connections and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. Selection of Lighting Options: Public Service will assist in the selection of lighting options by making recommendations for the most appropriate option based on the customer's defined illumination needs. However, responsibility for the final selection shall, at all times, rest with the customer. Any advice given by Public Service will be based on the customer's statements and by giving such advice, Public Service assumes no responsibility, nor shall it incur liability.

3. CHARGES FOR SERVICE

3.1. General: Charges for electrical usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for electrical usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard or Atypical Conditions, or for an Extension.

3.2. Definitions: The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded electric service from Public Service.
b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.
c) N.J.A.C. is the New Jersey Administrative Code.
d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus the sum of Basic Generation Service charges including SUT, and, unless included with Basic Generation Service charges, Transmission Charges, including SUT, derived from FERC approved transmission charges; all assessed in accordance with this Tariff for Electric Service.
e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for electric transmission (non-FERC jurisdictional) and/or distribution, whether located overhead or underground, on a public street or right of way, or on private property or private right of way, and includes the conductors, poles or supports, cable, conduit, rights of way, land, site restoration, handholes, manholes, vaults, line transformers, protection devices, metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the point of connection with the customer's facilities, but also includes the meter. Details of the requirements for Service Connections and Service Entrance Installations are provided in Sections 5 and 6 of these Standard Terms and Conditions and in the New Jersey Uniform Construction Code. The new plant and/or facilities installed constituting an Extension must be nominally physically and electrically continuous from the beginning to the end of the Extension, but also includes the meter.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where either: 1) Public Service facilities of the required voltage or number of phases did not previously exist, or 2) existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. Removal of Public Service Facilities: There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

3.4. Temporary Service: Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS

(Continued)

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will be furnished only under Rate Schedules GLP, LPL, and HTS except that it will not be supplied for cogeneration or standby purposes under any rate schedule at locations where electric service is regularly supplied from another source, nor will it be supplied under Rate Schedules BPL, BPL-POF and PSAL.

3.5. Provision of Service: Electric service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon Applicant's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. Standard Conditions: Overhead construction will be utilized for all distribution lines except in certain areas designated by Public Service as underground zones where underground construction will be utilized. An area is designated as an underground zone by Public Service based upon load density, area size, building occupation and the need for multiple and/or express circuits.

3.5.2. Atypical Conditions: When underground distribution lines or service connections in overhead zones are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such underground construction over the estimated costs of equivalent overhead construction, such total grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges, Facilities Charges, distribution capacity reservation charges or other charges as may be equitable under the circumstances involved where: (1) large or special investment is either necessary for the supply of service or is requested by the Applicant; (2) oversized transformers, feeders, or other special facilities are installed to serve an Applicant using equipment in such manner that the use of electric service is intermittent, momentary or subject to violent fluctuations; (3) capacity required to serve Applicant's equipment is out of proportion to the use of electric service for occasional or low load factor purposes, or is for short durations; or (4) service characteristics requested by Applicant differ from those normally supplied for a given size and type of load as specified in the current "Information and Requirements for Electric Service".

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

Facility Charges will be assessed on a monthly basis equal to 1.45% (1.55% including SUT) times the total installed cost of the excess facilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 15**

STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the Applicant to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. Where a large portion of the cost of construction is related to the installation of underground facilities, the costs may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

   Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $15,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 16**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.2. Multi-unit Developments: Where application for service is made for electric service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) The Regulations on Residential Underground Extensions, New Jersey Administrative Code 14:5-4.1 *et seq.* shall apply regarding the installation of Public Service facilities within the boundaries of such applicable developments. Such charges, referred to hereafter as B.U.D. Charges, are included elsewhere in this Tariff and shall be treated as a non-refundable contribution.

b) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions and, if applicable, B.U.D. Charges, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where the ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

c) As each unit is connected, as determined by the setting and activation of the Public Service electric meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

d) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

f) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 17**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, less ten times the estimated average annual distribution revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service electric meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 18**

STANDARD TERMS AND CONDITIONS
(Continued)

3.8. Charges for Increased Load: When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2. (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

4. CHARACTERISTICS OF SERVICE

4.1. General: The standard service supply of Public Service is alternating current with a nominal frequency of 60 hertz (cycles per second). All types of service listed below are not available at all locations, and service from the primary distribution, subtransmission, transmission or high voltage system may be specified under special conditions, such as location, size, or type of load. The customer shall ascertain and comply with the service characteristics requirements of Public Service which are covered in detail in “Information and Requirements for Electric Service,” issued by Public Service and available on request.

Public Service must always be consulted to determine the type of service to be supplied to a particular installation. The type of service may govern the characteristics of equipment to be connected.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 19**

STANDARD TERMS AND CONDITIONS
(Continued)

4.2. Types of Service: Subject to the restrictions in Section 4.1, the types of service available, with their nominal voltages are:

Type of Service		Volts
Secondary Distribution Service	Single-phase, two-wire	120
	Single-phase, three wire	120/240
	Single-phase, three-wire	120/208
	Three-phase, three-wire	240
	Three-phase, four wire	120/240
	Three-phase, four wire	120/208
	Three-phase, four-wire	277/480
Primary Distribution Service	Three-phase, four wire	2,400/4,160
	Three-phase, four-wire	13,200
Subtransmission Service:	Three-phase, three-wire	26,400
	Three-phase, three-wire	69,000
High Voltage Service:	Three-phase, three-wire	138,000
	Three-phase, three-wire	230,000
Transmission Service	Three-phase, three-wire	69,000

4.3. Losses: Nominal electric losses and unaccounted for percentages:

Type of Service	Losses
Secondary Distribution Service:	5.8327%
Primary Distribution Service:	3.3153%
Subtransmission Service:	2.0472%
Transmission High Voltage Service:	0.8605%

5. SERVICE CONNECTIONS

5.1. General: The customer shall consult Public Service before starting work, to determine the type of service facilities involved, the exact location of the point of connection between customer's service entrance and Public Service's facilities and the construction to be installed by each.

Electric service will be supplied to each building or premises through a single service connection unless otherwise agreed in accordance with the detailed requirements of "Information and Requirements for Electric Service," Section 3.

Whenever conductors are required under or within a building to provide a continuous service run to the customer's entrance equipment, they shall be installed by Public Service at the expense of the customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 20**

STANDARD TERMS AND CONDITIONS
(Continued)

Where a customer is provided Subtransmission, Transmission or High Voltage Service, the customer's high side bus shall be considered part of the Public Service distribution system for operational purposes with no remuneration to the customer by Public Service.

5.2. Overhead Service: For overhead service in overhead zones, Public Service will furnish, install, and maintain the overhead service facilities to the point of connection to the customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.3. Underground Service in Underground Zone: For underground service in underground zones, Public Service will furnish, install, and maintain the underground service facilities to the point of connection to customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.4. Underground Service in Overhead Zone:

5.4.1. Secondary Distribution Service: Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is inadequate for the size of customer's load, the customer shall furnish and install at its expense and in accordance with the specifications of Public Service the primary conduits and any necessary manholes, which will be maintained by Public Service. The customer shall also be required to furnish, install, and maintain all secondary conduits and conductors and provide space on its property for necessary transformation.

Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is adequate for the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install the service facilities at its expense and in accordance with the specifications of Public Service. Public Service will connect the service conductors and maintain the service facilities without charge to the customer.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.4.2. Primary Distribution Service: Where underground service in an overhead zone is to be supplied, and primary voltage supply is required because of the size of the customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 21**

STANDARD TERMS AND CONDITIONS

(Continued)

5.4.3. Subtransmission Service: Where underground service in an overhead zone is to be supplied, and subtransmission voltage supply is required because of the size of customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.5. Change in Location of Existing Service Line: Any change requested by the customer in the location of the existing service line, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. SERVICE ENTRANCE INSTALLATIONS

6.1. General: The customer is required to furnish, install, and maintain the service entrance wiring and equipment on the customer's premises with the exception of transformers and network protectors for secondary service, and meters and metering equipment as enumerated in detail in the following paragraphs. All materials and equipment used shall be of a type approved by Public Service and must be installed according to the requirements of governmental authorities, Public Service, and the current edition of the National Electrical Code. The location of the service entrance installation must be designated by Public Service.

6.2. Seals: Public Service will seal or lock all meters and enclosures containing meters and associated metering equipment, service entrance interrupting devices acceptable to Public Service, or unmetered wiring. No person except a duly authorized employee of Public Service is permitted to break or remove a Public Service seal or lock.

6.3. Secondary Distribution Service: For new installations to be metered at voltages not exceeding 600 volts, meter-mounting equipment and, where required, current transformers, potential transformers, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

For large secondary installations, the customer may be required to furnish a vault or space for a transformer mat, pad, manhole, or vault.

The customer shall ascertain and comply with the general requirements of Public Service for secondary installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 22**

STANDARD TERMS AND CONDITIONS

(Continued)

6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service: For new installations to be metered at voltages exceeding 600 volts, meter-mounting equipment, current transformers, potential transformers, test switches, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

Where service is received at primary distribution, subtransmission, transmission or high voltage entrance voltages, customer must furnish, install and maintain a service entrance interrupting device acceptable to Public Service and, where necessary, transformers and appurtenances.

The customer shall ascertain and comply with the general requirements of Public Service for primary distribution, subtransmission, transmission or high voltage service installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

Where subtransmission, transmission or high voltage service is supplied, it is necessary that the switching operations be controlled by Public Service; therefore, customer shall agree to abide by the operating instructions issued to customer by Public Service.

7. METERS AND OTHER EQUIPMENT

7.1. General: The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

Public Service will select the type and make of metering and its other equipment, and may, from time to time, change or alter such equipment; its sole obligation is to supply metering that will furnish accurate and adequate records for billing purposes.

Electric service normally will be supplied to each building or premises at a single metering point, by one watthour meter equipped, where necessary, with demand and recording devices. Additional meters will be installed (1) where, in the judgment of Public Service, the operating characteristics of its system require the installation of more than one meter, or (2) at the customer's request provided that the service measured by each meter shall be billed separately at an applicable rate schedule.

No person except a duly authorized employee or agent of Public Service is permitted to alter or change a meter or its connection.

When requested by a customer, equipment to provide data pulses and/or advanced interval meter access may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

A customer may choose to opt-out of remote meter reading and request a conventional meter and will be charged additional fees as detailed in Section 9.4.1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 23**

STANDARD TERMS AND CONDITIONS

(Continued)

7.2. Other Devices: No branch circuits or devices are permitted on the supply side of the meter, except those for Police Recall or Fire Alarm System Service as provided in this Tariff.

Public Service will not permit the connection of the customer's ammeters, voltmeters, pilot lamps, or any other energy-using devices to the instrument transformers used in conjunction with its meter.

7.3. Protection of Meters and Other Equipment: Customer shall provide for the safekeeping of the meter and other equipment of Public Service, and shall not tamper with or remove such meter or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or its agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

7.4. Tampering: In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such electric service under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, based upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service under the applicable rate schedule, exclusive of any reduction in charges for third party supplied electric services, alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 24**

STANDARD TERMS AND CONDITIONS
(Continued)

8. CUSTOMER'S INSTALLATION

8.1. General: Public Service makes no new electric installations on the customer's premises other than the installation of its services, meters and other equipment as set forth in these Standard Terms and Conditions except to continue a service run, a portion of which is installed under or within a building at the customer's expense. Public Service will assume no responsibility for the condition of customer's electric installation or for accidents, fires, or failures which may occur as the result of the condition of such electric installation. No material change in the size, total electrical capacity, or method of operation of customer's equipment shall be made without previous written notice to Public Service.

Failure of the Customer to give prior notice of changes in conditions as described above shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees.

8.2. Wiring: Wiring installed on the customer's premises must conform to all requirements of governmental authorities and to the regulations set forth in the current edition of the National Electrical Code.

8.3. Inspection and Acceptance: The customer's service entrance installation must be inspected and approved by Public Service before service will be supplied. Public Service may refuse to connect with any customer's installation or make additions or alterations to the service connection when it is not in accordance with the National Electrical Code and with these Standard Terms and Conditions, and where a certificate approving the customer's electrical installation has not been issued by a county or a municipality or by any other organization authorized to perform such functions and services as may be designated and approved by the Board of Public Utilities. Information regarding the above inspection service is detailed in "Information and Requirements for Electric Service," issued by Public Service and available on request.

8.4. Customer On-Site Generation:

8.4.1. General: Electric service from a customer's on-site generation facility, or from sources other than that delivered by Public Service's system shall not be used for the operation of customer's electrical equipment without previous written notice to Public Service. The requirements in this Section 8.4.1 do not apply when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

8.4.2. Parallel Operation: Customer may operate on-site generation facility in parallel with the service delivered by Public Service only with previous written notice to Public Service and written Public Service approval**,** and must conform with all applicable interconnection standards.

Public Service may re-energize the Public Service delivery service following an interruption without prior notice to the customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 25**

STANDARD TERMS AND CONDITIONS
(Continued)

8.5. Maintenance of Customer's Installation: Customer's entire electrical installation shall be maintained in the condition required by the electrical inspection agency having jurisdiction and by Public Service, and all repairs shall be made by the customer at their expense. Preventative and corrective maintenance on customer owned equipment is the responsibility of the customer. Further, customer electrical equipment under the operational control of Public Service shall be subject to Public Service's inspection and where necessary Public Service will advise the customer to make necessary repairs at customer expense. In the event PSE&G provides assistance in repairs or maintenance activities, customers will be responsible for those costs. If the customer fails to make the necessary repairs in a timely manner, then Public Service will have the repairs made and bill the customer.

8.6. Electrical Equipment and Appliances: Motors, welders, and other electrical equipment and appliances shall be so wired, connected, and operated as to produce no disturbing effects on the Public Service electrical system which will affect the adequacy or quality of service to other customers.

Where the use of electric service is to be intermittent, occasional or momentary, or subject to violent fluctuations, or for low load factor purposes or for short durations equipment shall not be connected without previous written notice to Public Service.

8.7. Power Factor: The average power factor under operating conditions of customer's load at the point where the electric service is metered shall not be less than 85%. Public Service may inspect customer's installed equipment and may place instruments for test purposes at its own expense on the premises of the customer.

Where neon, fluorescent, or other types of lighting or sign equipment having similar low power factor characteristics are installed or moved to a new location, the customer shall furnish, install, and maintain at its own expense corrective apparatus which will increase the power factor of the individual units or the entire lighting installation to not less than 90%.

8.8. Liability for Customer's Installation: Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customer's facilities or the equipment of others on customer's premises. Public Service will not be liable for the use, care or handling of the electric service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customer's facilities.

8.9. Replacement of Customer Owned Equipment Due to System Upgrades: If customer owned communication equipment, such as relays, requires replacement in order to be compatible with PSE&G's system due to upgrade work being performed by PSE&G, the Company will provide the replacement at no cost to the Customer. Any equipment replaced by PSE&G under this section shall be owned by PSE&G. In all other circumstances including customer requirements or obsolescence, the equipment will be replaced at their expense and in accordance with other sections of this tariff.

9. METER READING AND BILLING

9.1. Measurement of Electric Service: Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 26**

STANDARD TERMS AND CONDITIONS

(Continued)

Where more than one meter is furnished and installed for Public Service operating reasons, as set forth in Section 7.1 of these Standard Terms and Conditions, the kilowatt-hour use measured by the meters will be combined for billing purposes at an applicable rate schedule selected by the customer.

When demand is measured, the customer's monthly maximum demand shall be the sum of the maximum kilowatt demands, determined in accordance with the provisions of the selected rate schedule, as recorded by the individual meters.

Where more than one meter is furnished and installed at the request of the customer, kilowatt-hour use and kilowatt demand measured by each meter will be billed separately at an applicable rate schedule selected by the customer.

Bills will be based upon registration of Public Service meters, except as otherwise provided for in this tariff.

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premises is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors. The Generation Obligation for customers taking service in a new facility, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premises. More specifically the customer's Generation Obligation is established based upon the following: 1) an estimate of the customer's peak demand, based upon the load shape of a representative sample of customers served under the same rate schedule, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer's actual or estimated, as applicable, summer peak demand, depending upon the type of metering equipment installed by Public Service, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once a year.

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above.

9.2. Metering on Customer's Premises:

9.2.1. General: The service and supply of electrical energy by Public Service for the use of owners, landlords, tenants or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters.

The service and supply of electrical energy by Public Service to owners, landlords, tenants or occupants of industrial or commercial buildings or residential premises as noted below in Section 9.2.2 and not limited by the above paragraph may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying electric service from Public Service be permitted to resell it for a profit.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 27**

STANDARD TERMS AND CONDITIONS
(Continued)

9.2.2. Sub-Metering: The practice where a customer of Public Service or a customer of record, through the use of direct metering devices, installed, maintained and operated at such customer's expense, monitors, evaluates or measures their own consumption of electrical energy or the consumption of a tenant for accounting or conservations purposes.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all electric consuming devices must be metered through a single sub-meter.

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

9.3. Testing of Meters: At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

9.4. Metering Options: The following optional metering services are available to customers and are subject to the charges as indicated in the following subsections:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 28**

STANDARD TERMS AND CONDITIONS

(Continued)

9.4.1. Remote Meter Reading (AMI): In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, Public Service currently provides remote capable AMI meters as the standard equipment. For residential customers only, a non-communicating meter can be installed at the customer's expense.

In the event the customer chooses not to have an interval meter/advanced meter installed on their premises, the following fees shall apply.

Type of Service	Set-Up Charge	Charge Including SUT	Monthly Charge	Monthly Charge Including SUT
Meter Change (residential only)	$45.00	$47.98		
Monthly meter reading fee			$12.00	$12.79

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 29**

STANDARD TERMS AND CONDITIONS
(Continued)

9.4.2. Customer Access to Meter Data:

a) **Data Pulses:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use at the customer's request, in accordance with the applicable charges listed below. Customers requesting these services are subject to a minimum term of one year.

Type of Service	Set-Up Charges	Set-Up Charges Including SUT	Monthly Charge
Single Phase	$ 364.52	$ 388.67	$ 1.00
Three Phase	364.52	388.67	2.00
Three Phase – time and data pulses	410.00	437.16	3.00

b) **Access to Historical Interval Usage Data:** Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical interval usage data on a next-day basis through the customer account portal, including Green Button download.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 30**

STANDARD TERMS AND CONDITIONS

(Continued)

9.5. Billing Adjustments: Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RS, RHS or RLM, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments will be made in accordance with N.J.A.C. 14:3-4.6.

9.6. Meter Reading and Billing Period: All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

9.7. Proration of Monthly Charges: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts, the minimum period for billing purposes shall be one month.

9.8. Averaged Bills: Where Public Service is unable to read the meter, Public Service may estimate the amount of electric service supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue electric service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours, or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

9.9. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RS or RHS or GLP (where GLP electric service is used for residential purposes in buildings of four or fewer units) shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve-month period will be averaged over twelve months and may be paid in twelve equal monthly installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 31**

STANDARD TERMS AND CONDITIONS
(Continued)

9.10. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of electric service subsequent to the scheduled meter reading date for the immediately preceding month.

9.11. Payment of Bills: At least 15 days time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow a customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

9.12. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedules RS, RHS, RLM, WH, WHS, BPL and BPL-POF. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills, and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 32**

STANDARD TERMS AND CONDITIONS

(Continued)

9.13. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

9.14. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules GLP, LPL, PSAL, HS and HTS.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized government officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) nonpayment of a valid bill due for service furnished at a present or previous location, however, nonpayment for business service shall not be a reason for discontinuance of residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 9.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

Public Service shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for nonpayment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $200.00; and 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for nonpayment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 33**

STANDARD TERMS AND CONDITIONS
(Continued)

landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 9.11 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of nonpayment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for nonpayment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. and 4:00 P.M., Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or a holiday, absent such emergency.

Subject to the conditions set forth below, discontinuance of residential service for nonpayment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. Discontinuance shall be prohibited for a period of 90 days initially when a customer submits a licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provisions of N.J.A.C. 14:3-7.6.

1. The Board may extend the 90-day period for good cause upon the receipt of a written request from the customer. The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for non-payment prior to submission of the licensed medical professional's statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 34**

STANDARD TERMS AND CONDITIONS
(Continued)

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for nonpayment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 35**

STANDARD TERMS AND CONDITIONS

(Continued)

13.2. Emergencies: Public Service may curtail or interrupt service or reduce voltage to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

In the event of an actual or threatened restriction of electric supplies available to its system or the systems to which it is directly or indirectly connected, Public Service may, after due notice to the Board, curtail or interrupt service or reduce voltage to any customer or customers if such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of electric service it will supply and may refuse service to new customers or to existing customers for additional load if the necessary electric supply is unavailable or if Public Service is or will be unable to deliver, the necessary energy, or to obtain the necessary equipment and facilities to supply such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Electric Supply: Customers served on any of the applicable rate schedules of this Tariff for Electric Service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier (TPS) must provide appropriate authorization as required by the TPS. Customers who are not enrolled with a TPS will continue to receive Basic Generation Service electric supply.

A TPS is a retail energy and capacity provider that has been licensed by the Board and has executed a Third Party Supplier Agreement with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. The customer may act as a third party supplier for its account if the customer meets all of the requirements of this Tariff.

14.1.1. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain a TPS for electric supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center.

14.2. Initiation of Service: In order to be eligible to receive electric supply from a TPS, the customer must contract with a TPS to obtain electric supply for delivery to the customer by Public Service. Delivery of electric supply to retail customers will be provided in accordance with the terms of the Third Party Supplier Agreement. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of electric supply. Initiation of service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection.

Once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, which process is as set forth in this subsection and in Section 14.1, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer. This letter of confirmation shall be provided within one day and shall include notification of the customer's right to rescind their contract with their designated TPS in accordance with Board established procedures. This right to rescind must be exercised within seven (7) days of mailing of the letter of confirmation. In the event of a dispute, assignment of a customer will not

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 36**

STANDARD TERMS AND CONDITIONS

(Continued)

occur unless and until the dispute is resolved. Once assignment has occurred, the TPS will be required to provide all of the electric supply consumed on the Public Service customer's account (single point of delivery).

14.2.1. Customer Change of Third Party Supplier: If a customer subsequently elects to change its TPS, the customer must provide appropriate authorization as required by their TPS and as set forth in Section 14.1 and Section 14.2. Service from this alternate TPS will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection. Upon enrollment with a TPS, the customer may not change its TPS more frequently then once every billing month cycle.

14.2.2. Customer Return to Public Service Rate Schedule Electric Supply:

a) If the customer subsequently returns to Public Service as supplier of electric supply, the return to Public Service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt of customer notification by Public Service. Public Service shall confirm the customer's selection of Public Service as its provider of electric supply by sending a letter of confirmation to the customer and the customer shall have the right to rescind in accordance with Section 14.2, Initiation of Service, of these Standard Terms and Conditions.

b) If a customer's TPS no longer satisfies the requirements imposed on it by the Third Party Supplier Agreement, such customer shall immediately return to, and receive electric supply from Public Service under customer's applicable rate schedule unless and until customer selects another TPS in accordance with Section 14.2.1. The customer shall be advised by Public Service in writing of this change in supplier.

14.2.3. Third Party Supplier's Termination of Customer's Electric Supply: A TPS will not be permitted to physically connect or disconnect energy service to a customer.

14.3. Customer Billing Process: Public Service will provide one combined bill to the TPS's retail customer(s) containing both Public Service charges and TPS electric supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for TPS services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for TPS services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.3.1. Payment of Bills: Payment of bills, including TPS's charges for electric supply if billed by Public Service, shall be made to Public Service and shall be in accordance with Section 9, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 37**

STANDARD TERMS AND CONDITIONS

(Continued)

14.3.2. Late Payment Charges: A late payment charge in accordance with Section 9.12, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for electric supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for electric supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges, and all undisputed TPS charges for electric supply if such charges are billed by Public Service, in accordance with Section 9, Meter Reading and Billing, and Section 14.3.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customers and their TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.4. Continuity of Service: In addition to the terms specified in Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions, Public Service shall have the right (i) to require a TPS's electric supply sources to be disconnected from Public Service's electrical system; (ii) to otherwise curtail, interrupt, or reduce a TPS's electric supply; or (iii) to disconnect a TPS's customer(s) whenever Public Service determines, or whenever Public Service is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of Public Service's or PJM members' facilities; to maintain the safety and reliability of Public Service's electrical system and any generation facilities attached thereto; or due to Emergencies, minimum generation ("light load") conditions, forced outages, potential overload of Public Service's or PJM's transmission and/or distribution circuits or events of Force Majeure including, but not limited to, those events specified in Section 13.1, Continuity of Service, of these Standard Terms and Conditions.

14.5. Interval Metering: In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, customers being served by a TPS that have interval meters will be billed using the data obtained from those meters. If the interval meter is not operational, customer's hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 38**

STANDARD TERMS AND CONDITIONS
(Continued)

15. NET METERING INSTALLATIONS

15.1. **General:** For the purpose of this Section of the Tariff for Electric Service a customer-generator is a customer that generates electricity using Class I renewable resources as defined in N.J.A.C. 14:8-1.2 on the customer's side of the meter. Net Metering provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by Public Service to a Qualified Customer Generator, as defined in Section 15.2, in a given billing period and the electricity delivered by Qualified Customer Generator into the Public Service distribution system. Public Service will select and supply the type of meter(s) that will enable the measurement of the electricity for the billing or crediting of energy delivered as indicated above.

Customers qualified for Net Metering shall be responsible for all interconnection costs as defined in N.J.A.C. 14:8-4.1 *et seq*., which shall be in addition to any line or service extension charge required to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 3, Charges for Service, shall mean net usage as determined by Net Metering.

15.2. **Limitations and Qualifications for Net Metering:** To qualify for Net Metering, a customer-generator must generate Class I renewable energy as defined in N.J.A.C. 14:8-1.2. Further, to qualify for Net Metering, the capacity of the customer's generating system cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to the customer's residence or facility, as applicable, over an annualized period. Customer-generators that qualify for Net Metering shall be referred to as "Qualified Customer-Generators."

Additionally, customers participating in Community Solar cannot participate in Net Metering unless each project is metered separately.

15.3. **Installation Standards:** A Qualified Customer-Generator shall ascertain and comply with the requirements of Public Service which are covered in detail in the "Information and Requirements for Electric Service", available on www.pseg.com or by request as designated in Section 6.3, Secondary Distribution Service, of these Standard Terms and Conditions. In addition, the Qualified Customer-Generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 39**

STANDARD TERMS AND CONDITIONS

(Continued)

Qualified Customer-Generator's generating system shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, accredited testing institutions, such as Underwriters Laboratories. The customer's installation should be made in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply to standards established by Public Service and approved by the New Jersey Board of Public Utilities ("Board") in addition to the aforementioned applicable safety and power quality standards and all other requirements in N.J.A.C. 14:8-4.1 *et seq*.

15.4. Initiation of Service: Prior to interconnecting with the Public Service distribution system the Qualified Customer-Generator is required to provide Public Service with an Interconnection Application provided by the Office of Clean Energy and pay all appropriate charges as detailed in the Interconnection Application Process. Additionally, Public Service may, at its option, inspect the interconnection prior to the initiation of Net Metering service for Qualified Customer-Generators.

Initiation of service will become effective on the Qualified Customer-Generator's first regularly scheduled meter reading date that is at least twenty (20) days after the customer elects this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt of customer notification by Public Service. The Qualified Customer-Generator shall provide Public Service on a regular basis with access to the customer's telephone service when required for the purposes of acquiring metering data.

15.5. Net Billing: Where the amount of electricity delivered by the Qualified Customer-Generator plus any kilowatt-hour credits held over from the previous billing periods exceeds the electricity supplied by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, the Qualified Customer-Generator shall be credited for the excess kilowatt-hours to the next billing period. At the end of the annualized period the Qualified Customer-Generator will be compensated for any remaining credits by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, at their avoided cost of wholesale power.

A Qualified Customer-Generator shall have a one-time opportunity to select a monthly billing period as the start of the Qualified Customer-Generator's annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Qualified Customer-Generator notifies Public Service of the selection of their alternate monthly billing period. If a Qualified Customer-Generator initiating service after March 2, 2009 does not submit an annualized period selection they shall be assigned a default annualized period until such time as they notify Public Service of the selection of their alternate annualized period.

In the event that a Qualified Customer-Generator changes suppliers, the electric power supplier or basic service provider with whom service is terminated shall treat the end of the service period as if it were the end of the annualized period. Changes in supplier are to be in accordance with Section 14.2.1, Customer Change of Third Party Supplier, or Section 14.2.2, Customer Returns to Public Service Rate Schedule Electric Supply, of these Standard Terms and Conditions, as applicable.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 40**

STANDARD TERMS AND CONDITIONS

(Continued)

15.6. Billing Adjustments: In addition to Section 9.5, Billing Adjustments, of these Standard Terms and Conditions whenever a meter measuring energy delivered from a Qualified Customer-Generator to Public Service's distribution system is found to be registering slow by 2% or more an adjustment of the energy delivered shall be made and an adjustment may be made if the meter is found to be registering fast by more than 2%. The Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, will determine the applicability of this latter adjustment.

15.7. Budget Plan (Equal Payment Plan): The payment option described in Section 9.9, Budget Plan, is not available for customers taking service under this Section 15, Net Metering.

15.8. Program Availability: In accordance with N.J.S.A. 48:3-87(e)(1), Public Service may be authorized by the Board to cease offering net metering to customers that are not already net metered whenever the total rated generating capacity owned and operated by net metering customer-generators Statewide equals 5.8 percent of the total annual kilowatt-hours sold in this State by each electric power supplier and each basic generation service provider during the prior one-year period.

16. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Electric Service.

16.1. New Jersey Sales and Use Tax:
In accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

16.1.1. The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Agencies or instrumentalities of the federal government.

d) International organizations of which the United States of America is a member.

e) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 41**

STANDARD TERMS AND CONDITIONS

(Continued)

16.1.2. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 *et seq.*) and P.L.1966, c.30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

16.2. New Jersey Corporation Business Tax:
In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

16.2.1. The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 42**

STANDARD TERMS AND CONDITIONS

(Continued)

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 43
Original Sheet No. 44
Original Sheet No. 45
Original Sheet No. 46
Original Sheet No. 47

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 48**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

The following are the charges applicable for certain residential underground extensions, in compliance with the Regulations on Residential Underground Extensions as per N.J.A.C. 14:3-8 et seq., and referenced in the Sections 3.7.2. – Multi-unit Developments of the Standard Terms and Conditions of this tariff.

The Applicant will be charged for standard electric service as calculated in Section A – Base Charges and/or Section B – Additional Charges. The charges in Sections A and B will be adjusted for tax gross-up effects consistent with all applicable federal and state tax laws, including, but not limited to, the "Protecting Americans from Tax Hikes Act of 2015" ("the PATH Act"). For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction, such result shall include the gross-up for income tax effects. Such cost estimates shall be based on the unit costs as detailed in Exhibits I to III and shall be based on the necessary construction to supply the same loads and locations utilizing Public Service's standard design and construction standards. Requests for additional facilities shall be considered as Atypical Conditions and other charges may apply in accordance with Section 3.5.2 of these Standard Terms and Conditions.

Charges for street and area lighting provided by Public Service under Rate Schedules PSAL or BPL are as indicated in Section C – Street and Area Lighting Charges.

A. Base Charges:

		Charge Per Building Lot	Charge Per Foot For Total Front Footage
1.	Single-family	$ 529.43	$ 1.43
2.	Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase, high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 kVA, etc.	Charge to be based on differential cost according to unit costs specified in Exhibit I to III.	

B. Additional Charges:

	Item	Unit	Charge
1.	Primary termination.....	Each	$ 310.57
2.	Primary junction enclosure	Each	$ 1,639.80
3.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
4.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
	.....	Over 150 amp	$ 6.37
5.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
6.	Multi-phase constructions.....	Per foot per phase	$ (3.90)
7.	Pavement cutting and restoration, rock removal, blasting, difficult digging and special backfill	At actual low bid cost with option of Applicant to contract for as limited by N.J.A.C. 14:5-2.4 et seq.	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 49**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

C. Street and Area Lighting Charges:

The Applicant shall pay the normal charges for all luminaires as indicated in the applicable street and area lighting rate schedule.

The monthly charge and up-front contribution for all lighting poles not installed on public streets shall be at the full charges indicated in the applicable street and area lighting rate schedule.

1. Street lighting poles where spacing is equal to or greater than 200 feet.

   For street and area lighting poles installed on public streets, PSE&G will provide, as the standard lighting pole, a laminated wood pole (PSE&G part number W04-0197) at no up-front contribution or monthly charge. Requests for use of another type or size lighting pole shall be considered as a request for a Specialty Lighting Pole. In these cases, an up-front contribution credit equal to the installed cost of the standard lighting pole shall be provided by Public Service, with monthly charges calculated as per the applicable street and area lighting rate schedule.

2. Additional street lighting poles where spacing is less than 200 feet.

   The Applicant shall pay the full normal charges for lighting poles as indicated in the applicable street and area lighting rate schedule where the spacing of such lighting poles is less than 200 feet.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 50**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT I - UNIT COSTS OF UNDERGROUND CONSTRUCTION - SINGLE PHASE

	Item	Unit	Total Charge*
1.	Trenching		
	Sole Trenching	Per foot	$ 2.22
	Joint Trenching**	Per foot	$ 1.28
2.	Primary cable (1/0 AWG Al.)	Per foot	$ 3.93
3.	Secondary wire		
	2/0 AWG Cu	Per foot	$ 3.59
	350 kcmil Cu	Per foot	$ 10.75
4.	Services		
	50 feet complete - 100 & 150 amp	Each	$ 552.58
	100 & 150 amp (#2 AWG Cu.)	Per foot	$ 11.05
	50 feet complete - over 150 amp	Each	$ 675.06
	Service - over 150 amp (2/0 AWG Cu.)	Per foot	$ 13.50
5.	Primary termination - branch	Each	$ 1,563.94
6.	Primary junction enclosure - branch	Each	$ 2,294.67
7.	Secondary enclosure	Each	$ 692.09
8.	Street light cable (#8 AWG Cu.)	Per foot	$ 4.32
9.	Transformers - including fiberglass pad		
	25 kVA - single-phase	Each	$ 1,376.93
	50 kVA - single-phase	Each	$ 5,290.64
	75 kVA - single-phase	Each	$ 5,645.29
	100 kVA - single-phase	Each	$ 6,285.68
	167 kVA - single-phase	Each	$ 3,632.41
10.	Street light poles (standard pole only)		
	30 foot laminated pole	Each	$ 1,100.00

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

** Joint trench calculation: 0.5 (0.85 x $2.22) + 0.15 x $2.22 =$1.28

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 51**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT II - UNIT COSTS OF UNDERGROUND CONSTRUCTION - THREE-PHASE

	Item	Unit	Total Charge*
1.	Primary cable		
	750 kcmil Cu.	Per foot	$ 25.24
	500 kcmil Cu.	Per foot	$ 17.92
	4/0 AWG Al.	Per foot	$ 12.62
	1/0 AWG Al.	Per foot	$ 7.06
2.	Secondary 4-wire (350 kcmil Cu.)	Per foot	$ 11.34
3.	Primary Terminations		
	Main line (750 kcmil)	Set of 3	$ 3,387.34
	Three phase branch (500 kcmil)	Set of 3	$ 785.25
	Two phase branch (4/0 AWG)	Set of 2	$ 425.38
4.	5 inch conduit	Per foot	$ 6.27
	6 inch conduit	Per foot	$ 8.20
5.	Transformers - including fiberglass pad		
	150 kVA - three-phase	Each	$ 11,158.06
	225 kVA - three-phase	Each	$ 10,085.50
	300 kVA - three-phase	Each	$ 20,902.25
	500 kVA - three-phase	Each	$ 23,728.71
	700 kVa - three-phase	Each	$ 22,574.76
	1000 kVa - three-phase	Each	$ 34,287.53
	1500 kVa - three-phase	Each	$ 38,672.75

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 52**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT III - UNIT COSTS OF OVERHEAD CONSTRUCTION

SINGLE-PHASE AND THREE-PHASE

	Item	Unit		Total Charge*
1.	Pole line - including 7-35 foot and 2-40 foot poles, anchors and guys per 1000 feet	Per foot	$	6.48**
2.	Primary wire			
	1/0 AWG AAAC covered, one phase	Per foot	$	7.25
	379.5 kcmil Al. covered, three phase	Per foot	$	11.11
	1/0 AWG AAAC base, one phase	Per foot	$	7.30
	379.5 kcmil Al. bare, three phase	Per foot	$	10.85
3.	Primary wire neutral (1/0 AWG AAAC)	Per foot	$	2.76
4.	Secondary cable			
	3 wire (2/0 AWG Al.)	Per foot	$	5.16
	4 wire (2/0 AWG Al.)	Per foot	$	8.45
5.	Services - single-phase			
	50 feet complete - 100 & 150 amp	Each	$	259.25
	100 & 150 amp (#2 AWG Al.)	Per foot	$	5.19
	50 feet complete - over 150 amp	Each	$	379.01
	Over 150 amp (2/0 AWG Al.)	Per foot	$	7.58
	Services - three-phase			
	up to 200 amp (2/0 AWG Al.)	Per foot	$	7.76
	over 200 amp (397.5 kcmil Al.)	Per foot	$	12.27
6.	Transformers			
	25 kVA - single-phase	Each	$	1,376.93
	50 kVA - single-phase	Each	$	5,285.99
	100 kVA - single-phase	Each	$	6,239.62
	3 - 25 kVA - three-phase	Per set	$	2,961.53
	3 - 50 kVA - three-phase	Per set	$	3,690.83
	3 - 100 kVA - three-phase	Per set	$	5,721.66

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

**Joint pole line cost to be used = $3.23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 53
Original Sheet No. 54
Original Sheet No. 55
Original Sheet No. 56

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 57**

SOCIETAL BENEFITS CHARGE

	Cost Recovery (per kilowatt-hour)
Component:	
Social Programs	$ 0.001728
Energy Efficiency and Renewable Energy Programs	0.003287
Manufactured Gas Plant Remediation	0.000471
Sub-total per kilowatt-hour	$ 0.005486

Charge including losses, USF and Lifeline:

	Loss Factor	Sub-total Including Losses	USF	Lifeline	Total Charge
Secondary Service	5.8327%	$ 0.005826	$ 0.001243	$ 0.000698	$ 0.007767
LPL Primary	3.3153%	0.005674	0.001243	0.000698	0.007615
HTS Subtransmission	2.0472%	0.005601	0.001243	0.000698	0.007542
HTS High Voltage & HTS Transmission	0.8605%	0.005534	0.001243	0.000698	0.007475

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	$ 0.008282
LPL Primary	0.008119
HTS Subtransmission	0.008042
HTS High Voltage & HTS Transmission	0.007970

SOCIETAL BENEFITS CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge.

(Charges are for illustrative purposes only and are based on the Tenth Revised Sheet No. 57 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 58**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This component shall recover costs associated with existing social programs. This includes but is not limited to uncollectible customers' accounts.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

The New Jersey Clean Energy Program energy efficiency and renewable energy programs (formerly CRA Programs) are approved by the Board pursuant to N.J.S.A. 48:3-60(a)(3). They include energy efficiency programs, customer-sited renewable energy programs, grid supply renewable energy programs and any other programs the BPU may approve. These programs may be administered and or implemented by Public Service, the BPU, or a third party appointed by the BPU. New Jersey Clean Energy Program Costs consist of, but are not limited to, rebates, grants, payments to third parties for program implementation, direct marketing costs, energy efficiency and renewable energy hardware, administration, measurement and evaluation of energy efficiency and renewable energy programs, customer communication and education, market research, costs associated with developing, implementing and obtaining regulatory approval, costs of research and development activities associated with energy efficiency and renewable energy programs, applicable Lost Revenues, and New Jersey Clean Energy Program advertising costs.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 59**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 60**

NON-UTILITY GENERATION CHARGE

Cost Recovery (per kilowatt-hour)

	St Lawrence NYPA Credit RS, RHS and RLM	Non-Utility Generation above market costs	Total
Total Cost per kilowatt-hour		$0.000023	
Amount per kilowatt-hour of cost recovery after application of losses:			
RS, RHS & RLM (Loss Factor =5.8327%)	($ 0.000000)	$0.000024	$0.000024
Other Secondary (Loss Factor =5.8327%)		0.000024	0.000024
LPL Primary (Loss Factor =3.3153%)		0.000024	0.000024
HTS Subtransmission (Loss Factor =2.0472%)		0.000023	0.000023
HTS High Voltage & HTS Transmission (Loss Factor =0.8605%)		0.000023	0.000023
Charges including New Jersey Sales and Use Tax (SUT)			
RS, RHS & RLM	($ 0.000000)	$0.000026	$0.000026
Other Secondary Service		0.000026	0.000026
LPL Primary		0.000026	0.000026
HTS Subtransmission		0.000025	0.000025
HTS High Voltage & HTS Transmission		0.000025	0.000025

NON-UTILITY GENERATION CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. This charge shall recover: 1) above market costs associated with non-regulated generation costs which are related to long-term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978 and 2) other generation costs as may be approved by the Board. Actual costs incurred by the Company will be subject to deferred accounting. The St. Lawrence New York Power Authority (NYPA) Annual Benefit Allocation credit reflects the annual Economic Benefit allocation for New Jersey's investor owned utilities to supply residential customers' load.

Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered Non-utility Generation above market cost balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 61**

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

	Charge (per kilowatt-hour)
ZERO EMISSION CERTIFICATE RECOVERY CHARGE:	
Charge	$ 0.004000
Return of Excess Collections	$ 0.000000
Total Charge	$ 0.004000
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.004265

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below.
Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091004, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per kWh for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c. 16 ("ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC Law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate, interest-bearing account and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in Docket No. EO18080899.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 62
Original Sheet No. 63

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 64**

SOLAR PILOT RECOVERY CHARGE

	Charge (per kilowatt-hour)
SOLAR PILOT RECOVERY CHARGE:	
Charge	$ 0.000063
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000067

SOLAR PILOT RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery by the Company is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 64 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 65**

GREEN PROGRAMS RECOVERY CHARGE

Component:	**Charge (per kilowatthour)**
Carbon Abatement Program	($0.000010)
Energy Efficiency Economic Stimulus Program	0.000004
Solar Generation Investment Program	0.000297
Solar Loan II Program	0.000109
Energy Efficiency Economic Extension Program	0.000034
Solar Generation Investment Extension Program	(0.000222)
Solar Loan III Program	0.000015
Energy Efficiency Economic Extension Program II	0.000108
Solar Generation Investment Extension II Program	(0.000105)
Energy Efficiency 2017 Program	0.000268
Transition Renewable Energy Certificate Program	0.002480
Clean Energy Future - Energy Efficiency Program	0.001257
Successor Solar Incentive Program	0.000601
Community Solar Energy Program	0.000084
Sub-total per kilowatthour	$0.004920
Charge including New Jersey Sales and Use Tax (SUT)	$0.005246

GREEN PROGRAMS RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	Conservation Incentive Program including SUT	
RS & RHS	$0.000271	$0.000289	Per kilowatt-hour
RLM	$0.000965	$0.001029	Per kilowatt-hour
GLP	$1.2193	$1.3001	Per kilowatt of monthly peak demand
LPL-S	$1.0290	$1.0972	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company's books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer ("ARC") shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 66 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer ("BRC") shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I: RS & RHS
Group IA: RLM
Group II: GLP
Group III: LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65^{o}F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2022-2023 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2023	989	
February 2023	838	
March 2023	684	
April 2023	354	187
May 2023	128	931
June 2022		3,043
July 2022		5,624
August 2022		4,861
September 2022		2,237
October 2022	228	414
November 2022	523	
December 2022	816	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2022-2023 Winter Period for HDD and 2022 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	HDD	THI	HDD	THI	HDD	THI
January 2023	469,298	150,909	11,303	409	6,341	1,577
February 2023	469,294	150,908	11,258	407	6,286	1,563
March 2023	469,288	150,906	11,276	408	6,207	1,543
April 2023	469,533	150,984	11,219	406	6,200	1,541
May 2023	469,777	151,063	11,163	404	6,193	1,540
June 2022	463,870	149,164	11,707	423	6,341	1,577
July 2022	461,601	148,434	11,568	418	6,287	1,563
August 2022	460,471	148,070	11,545	418	6,588	1,638
September 2022	461,466	148,390	11,469	415	6,061	1,507
October 2022	460,832	148,186	11,445	414	6,172	1,534
November 2022	461,133	148,283	11,350	410	6,412	1,594
December 2022	462,271	148,649	11,347	410	6,289	1,563

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	RS & RHS	RLM	GLP	LPL-S
Jun	$32.30	$90.17	$130.32	$2,691.79
Jul	39.76	102.12	150.23	3,943.65
Aug	36.78	95.84	145.41	3,981.31
Sep	22.10	43.79	90.80	2,236.34
Oct	13.79	17.31	54.66	1,623.92
Nov	14.98	15.85	48.76	1,008.96
Dec	18.58	20.42	48.68	863.90
Jan	20.61	22.23	52.13	926.21
Feb	17.06	19.36	49.77	928.65
Mar	16.39	18.57	49.83	930.16
Apr	13.98	14.68	49.36	886.19
May	15.43	18.93	87.85	1,721.67
Total Annual	**$261.75**	**$479.26**	**$957.80**	**$21,742.74**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66D**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 67**

DISTRIBUTION ADJUSTMENT CHARGE

	Charge (per kilowatthour)
Component:	
Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Charge including New Jersey Sales and Use Tax (SUT)	$0.XXXXXX

DISTRIBUTION ADJUSTMENT CHARGE

This non-bypassable charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 68**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 69**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per kilowatt-hour	Charge per kilowatt-hour Including SUT
RS	($0.005250)	($0.005598)
RHS	($0.006603)	($0.007040)
RLM	($0.004760)	($0.005075)
WH	($0.000000)	($0.000000)
WHS	($0.000000)	($0.000000)
HS	($0.003743)	($0.003991)
GLP	($0.001622)	($0.001729)
LPL – Secondary	($0.000929)	($0.000991)
LPL – Primary	($0.000600)	($0.000640)
HTS – Subtransmission	($0.000563)	($0.000600)
HTS – High Voltage & HTS – Transmission	($0.000224)	($0.000239)
BPL	($0.000000)	($0.000000)
BPL-POF	($0.001418)	($0.001512)
PSAL	($0.000000)	($0.000000)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 69 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 70**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RS					
Service Charge	per Month	$4.95	$0.00	$0.00	$4.95
Distribution 0-600, June-September	per kWhr	0.040752	0.007484	0.007980	0.048732
Distribution 0-600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
Distribution over 600, June-September	per kWhr	0.044826	0.007484	0.007980	0.052806
Distribution over 600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
RHS					
Service Charge	per Month	4.95	0.00	0.00	4.95
Distribution 0-600, June-September	per kWhr	0.051834	0.004222	0.004501	0.056335
Distribution 0-600, October-May	per kWhr	0.034956	0.001935	0.002063	0.037019
Distribution over 600, June-September	per kWhr	0.057058	0.004222	0.004502	0.061560
Distribution over 600, October-May	per kWhr	0.016190	0.001935	0.002063	0.018253
Common Use	per kWhr	0.057058	0.004222	0.004502	0.061560
RLM					
Service Charge	per Month	13.94	0.00	0.00	13.94
Distribution, June-September, On-Peak	per kWhr	0.075220	0.006391	0.006814	0.082034
Distribution, June-September, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, On-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
WH					
Distribution	per kWhr	0.050538	0.002084	0.002222	0.052760
WHS					
Service Charge	per Month	0.63	0.04	0.04	0.67
Distribution	per kWhr	0.001722	0.000310	0.000331	0.002053

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 70 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 71**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HS					
Service Charge	per Month	$3.74	$0.24	$0.26	$4.00
Distribution, June-September	per kWhr	0.102660	0.001730	0.001844	0.104504
Distribution, October-May	per kWhr	0.030703	0.000631	0.000672	0.031375
GLP					
Service Charge	per Month	4.77	0.31	0.33	5.10
Service Charge-Unmetered	per Month	2.21	0.13	0.14	2.35
Service Charge-Night Use	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.9378	0.0729	0.0777	4.0155
Summer Demand, June-September	per kW	9.8746	0.1830	0.1952	10.0698
Distribution, June-September	per kWhr	0.003219	0.000060	0.000064	0.003283
Distribution, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, June-September	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
LPL-Secondary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.7617	0.0944	0.1007	3.8624
Summer Demand, June-September	per kW	8.9495	0.2245	0.2393	9.1888
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
LPL-Primary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Service Charge-Primary Alternate	per Month	21.54	1.38	1.47	23.01
Annual Demand	per kW	1.7531	0.0443	0.0473	1.8004
Summer Demand, June-September	per kW	9.7321	0.2457	0.2620	9.9941
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 71 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 72**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HTS-Subtransmission					
Service Charge	per Month	$2,038.02	$0.00	$0.00	$2,038.02
Annual Demand	per kW	1.1432	0.0720	0.0768	1.2200
Summer Demand, June-September	per kW	4.1326	0.2603	0.2775	4.4101
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
HTS-High Voltage					
Service Charge	per Month	1,834.22	0.00	0.00	1,834.22
Annual Demand	per kW	0.6574	0.0156	0.0167	0.6741
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
BPL					
Distribution	per kWhr	0.007181	0.000159	0.000170	0.007351
BPL-POF					
Distribution	per kWhr	0.007174	0.000203	0.000216	0.007390
PSAL					
Distribution	per kWhr	0.007660	0.000171	0.000182	0.007842

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 72 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 73 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 74**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May: Energy & Capacity Charges	For usage in each of the months of October through May: Charges Including SUT	For usage in each of the months of June through September: Energy & Capacity Charges	For usage in each of the months of June through September: Charges Including SUT
RS – first 600 kWh	$ 0.075527	$ 0.080531	$ 0.072237	$ 0.077023
RS – in excess of 600 kWh	0.075527	0.080531	0.081381	0.086772
RHS – first 600 kWh	0.076746	0.081830	0.068808	0.073367
RHS – in excess of 600 kWh	0.076746	0.081830	0.081036	0.086405
RLM On-Peak	0.089221	0.095132	0.094156	0.100394
RLM Off-Peak	0.064475	0.068746	0.059459	0.063398
WH	0.068204	0.072723	0.066577	0.070988
WHS	0.066441	0.070843	0.066429	0.070830
HS	0.078509	0.083710	0.075325	0.080315
BPL	0.066509	0.070915	0.061239	0.065296
BPL-POF	0.066509	0.070915	0.061239	0.065296
PSAL	0.066509	0.070915	0.061239	0.065296

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fourteenth Revised Sheet No. 75 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 76**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in all months Transmission Charges	 Charges Including SUT
RS	$0.057428	$0.061233
RHS	0.037541	0.040028
RLM On-Peak	0.124829	0.133099
RLM Off-Peak	0.000000	0.000000
WH	0.000000	0.000000
WHS	0.000000	0.000000
HS	0.047976	0.051154
BPL	0.000000	0.000000
BPL-POF	0.000000	0.000000
PSAL	0.000000	0.000000

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May Charges	 Charges Including SUT	For usage in each of the months of June through September Charges	 Charges Including SUT
GLP	$0.067068	$0.071511	$0.067343	$0.071804
GLP Night Use	0.063526	0.067735	0.059237	0.063161
LPL-Sec. under 500 kW				
On-Peak	0.070936	0.075636	0.075223	0.080207
Off-Peak	0.063526	0.067735	0.059237	0.063161

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifteenth Revised Sheet No. 76 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 77
Original Sheet No. 78

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$ 1.6327
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.7409
Charge applicable in the months of October through May	$ 1.6327
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.7409

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 79 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 80**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 81**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge	$(0.006791)
Charge including New Jersey Sales and Use Tax (SUT)	$(0.007241)

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 81 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$10.0663
Charge including New Jersey Sales and Use Tax (SUT)	$10.7332
Charges applicable in the months of October through May	$10.0663
Charges including New Jersey Sales and Use Tax (SUT)	$10.7332

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 82 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 83 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 84**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge	$0.003332
Charge including New Jersey Sales and Use Tax (SUT)	$0.003553

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 84 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 85
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 87**

THIRD PARTY SUPPLIER

APPLICABLE TO:

A third party supplier is an entity that has executed a Third Party Supplier Agreement (Agreement) with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. This Agreement sets forth the specific terms and conditions with which Third Party Suppliers must comply to use Public Service's distribution system to supply energy to retail customers in Public Service's service territory. This Agreement is standardized in form and will apply in an equal and uniform manner to all Third Party Suppliers requesting to provide competitive energy supply to retail customers in Public Service's service territory. The Agreement is hereby incorporated by reference herein, and similarly incorporates this Tariff for Electric Service in its terms.

All modifications to the Agreement must be approved by the Board, consistent with the process set forth below, prior to implementation. Any such modifications, other than Third Party Supplier fee changes, shall be undertaken in accordance with the following procedures. Specifically, Public Service may amend the Agreement by providing simultaneous written notice of such change, by regular mail, or electronic means, to the Board of Public Utilities (Board), Division of Ratepayer Advocate (RPA), Jersey Central Power and Light, Atlantic City Electric Company, Rockland Electric and to Third Party Suppliers licensed as Electric Power Suppliers in New Jersey, a list of which will be provided by the Board. Within seventeen (17) days of such notice, the RPA or any New Jersey licensed Electric Power Supplier wishing to contest the amendment of the Agreement must submit in writing to the Board its reason for contesting the change, and must simultaneously provide a copy of such document to Public Service. Within forty-five (45) days of such notice, the Board may either (i) approve the amendment; (ii) determine through a suspension order that the proposed amendment needs further study, and thus place the request on hold pending future action by the Board; or (iii) take no action, in which case Public Service may implement the amendment at the conclusion of the forty-five (45) day period; provided, however, that the Board is not thereby precluded from taking action on the amendment in the future.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 88
Original Sheet No. 89
Original Sheet No. 90
Original Sheet No. 91
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour for RS non-Time of Use (TOU) customers:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution Charges per Kilowatt-hour for RS TOU customers (see Special Provision (a-8) for details)

For customers selecting two-period option (TOU-2P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	10 pm - 11 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

For customers selecting three-period option (TOU-3P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Mid-Peak	All other times	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	Midnight - 6 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

* Weekdays exclude PJM holidays.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 94**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 95**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use. This provision is only available to customers receiving this service under special provision (d);

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles. This provision is only available to customers receiving this service under special provision (d);

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.

(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(d-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.

(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.

(d-4) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.

(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(e-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Residential Time of Use**: RS customers may elect to take the RS TOU rate.

(d-1) Such customers will be required to stay on the RS TOU rate for a minimum of twelve (12) months.

(d-2) At the end of the initial 12-month period, the Company will provide the customer with reporting showing their 12-month bill on the new RS TOU rate and what their 12-month bill would have been on the non-TOU RS rate schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS TOU rate was higher compared to the RS rate schedule. This provision is available only to customers who enroll in RS TOU rates during the first twenty-four (24) months following the effective date of this tariff provision.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.034719	$ 0.037019	$ 0.052835	$ 0.056335

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.017119	$ 0.018253	$ 0.057735	$ 0.061560

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 100**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 101**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **General Limitations on Service:** This rate schedule is available where space heating equipment is permanently installed and is operated at not less than 208 volts and where all service is measured by one meter, except for service provided under Rate Schedules WH and WHS:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 102**

RATE SCHEDULE RHS

RESIDENTIAL HEATING SERVICE

(Continued)

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In individual apartments in a multiple-family building;

(a-3) In all-electric multiple-family building where electricity is furnished to the tenants as an incident to tenancy and is included in the rent, provided that the number of kilowatt-hours in each block of the Kilowatt-hour Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-4) Common-use equipment in an all electric multiple-family building in which each tenant is served individually under this rate schedule. The Distribution Charge for the kilowatt-hours used in each month shall be $0.057735 per kilowatt-hour ($0.061560 including SUT).

(b) **Limitations on Water Heating Service:** When electricity is used for water heating under this rate schedule, such service shall be to an automatic type water heater approved by Public Service; furthermore, if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time.

If water is centrally heated under (a-4), equipment shall be of an automatic type approved by Public Service, and billing under this rate schedule is not required.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(d-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(d-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 103
Original Sheet No. 104

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105 for Future**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 106**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 107**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108 for Future**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use;

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles.

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 109
Original Sheet No. 110

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 111**

RATE SCHEDULE WH
WATER HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to premises with controlled water heating installations that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Distribution Charges per Kilowatt-hour:

For all use during the controlled heating period	
Charge	Charge Including SUT
$ 0.049482	$ 0.052760

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 112**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WH.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 113**

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Electricity used for water heating during periods other than the controlled heating periods shall be registered on the meter measuring customer's other use and shall be billed under the rate schedule applicable to such other service;

(a-4) Service for controlled water heating will be controlled by a time switch and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 114**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

(a-7) Public Service shall furnish, install, and maintain a suitable time switch on the separate circuit for limiting to the controlled heating periods, hereinafter specified, the use of electric service at this rate schedule. The time switch shall remain the property of Public Service and shall be set and controlled exclusively by Public Service;

(a-8) The controlled heating period shall be normally from 11:00 P.M. of one day to 9:30 A.M. of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 115
Original Sheet No. 116

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 117**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for controlled water heating storage or for the electric heating elements of a water heating system connected to an active solar collection system. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$0.63 in each month [$0.67 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

For all use during the controlled storage heating period	
Charge	Charge Including SUT
$ 0.001925	$ 0.002053

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 118**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return the Safe Harbor Adjusted Repair Expense (SHARE) deductions to customers net of any offsets for deferred storm and regulatory costs, IRS adjustments and adjust for any major tax changes, such as tax reform. Interest at the two-year treasury rate plus 60 basis points. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WHS.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 119**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled storage heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Water heating equipment shall be operated at not less than 208 volts;

(a-4) Service for all water heating use will be controlled by a time switch or other control device and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch or other control device;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 120**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

(a-7) Where the water heater load does not preclude the use of a Public Service time switch or other control device, Public Service shall furnish, install, regulate and maintain a suitable time switch or other control device to limit the hours of energy available to the water heater. Where the water heater load does preclude the use of a Public Service time switch or other control device, the customer must furnish, install, and maintain a suitable relay, contact or other device which; in response to a Public Service signal, will energize the water heating installation;

(a-8) The controlled storage heating period shall be from 9 P.M. (EST) of one day to 7 A.M. (EST) of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 121
Original Sheet No. 122

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 123**

RATE SCHEDULE HS
BUILDING HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to permanently installed comfort building heating equipment in premises that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$3.75 in each month [$4.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

In each of the months of October through May		In each of the months of June through September	
Charges	Charges Including SUT	Charges	Charges Including SUT
$ 0.029426	$ 0.031375	$ 0.098011	$ 0.104504

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:
This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 124**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 125**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available for permanently installed comfort building heating where:

(a-1) Building heating equipment is operated at not less than 208 volts and has a total capacity of not less than five kilowatts;

(a-2) The wiring system metered under this rate schedule utilizes panels, troughs, conduit and wiring completely independent of the general lighting service for the building.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 126**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 127
Original Sheet No. 128

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 129**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.78 in each month [$5.10 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.7660	$ 4.0155	per kilowatt of Monthly Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.4441	$ 10.0698	per kilowatt of Monthly Peak Demand

Distribution Kilowatt-hour Charges:

In each of the months of October through May		In each of the Months of June through September		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$ 0.007858	$ 0.008379	$ 0.003079	$ 0.003283	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 130**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 131**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule GLP.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kW, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand shall be determined either by the registration of a demand meter furnished by Public Service or by estimate.

Where a demand meter is installed, the customer's Monthly Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval.

Where no demand meter is installed, the customer's Monthly Peak Demand shall be determined by estimate by dividing the kilowatt-hours by 100 for the applicable billing period.

New Customer: Where a new customer applying for service has an anticipated maximum Monthly Peak Demand of 10 kilowatts or more, that customer's Monthly Peak Demand shall be determined by measurement. If the anticipated maximum Monthly Peak Demand is less than 10 kilowatts, the demand may be determined by estimate or measurement.

Existing Customer: Where an existing customer's Monthly Peak Demand is determined, for billing, by measurement and is 10 kilowatts or greater in any of the preceding 12 months, the customer will continue to have their Monthly Peak Demand determined by measurement and is not eligible for determination by estimate.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 132**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Where an existing customer's Monthly Peak Demand is determined, for billing, by estimate and their monthly billed kilowatt-hours in any of the preceding 12 months exceeds 1,000 kilowatt-hours, or their Monthly Peak Demand exceeds 10 kilowatts by actual measurement, the customer will be converted to have their Monthly Peak Demand, for billing, determined by measurement. If customer's usage is always less than 1,000 kilowatt-hours per month, the customer may be billed under estimated or measured demand.

Self-Generation Customer: For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: The Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 133**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Service under this rate schedule will not be supplied where:

(a-1) The customers' Monthly Peak Demand exceeds 150 kilowatts in any month;

(a-2) The customer is presently served under Rate Schedule LPL-secondary and their Monthly Peak Demand has exceeded 100 kilowatts in any of the prior 24 consecutive months;

(a-3) The electrical capacity installed by Public Service exceeds 400 kilowatts.

Customers receiving service on the Building Heating Special Provision in July 2003 are exempt from the above limitation (a-1) and (a-3), where in any of the months of October through May the Monthly Peak Demand may exceed 150 kilowatts.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **Police Recall or Fire Alarm System Service:** Unmetered police recall or fire alarm system service will be furnished for signaling lamps, bells, or horns with an individual rating not greater than 100 watts or 1/8-horsepower, as rated by Public Service, at a charge of $0.180 ($0.192 including SUT) per month for each signaling lamp, bell, or horn connected, but the total charge shall in no case be less than $1.80 ($1.92 including SUT) per month. No other energy-using devices shall be connected to the police recall or fire alarm system. The customer shall provide, at its own expense, all necessary equipment and wiring, including the service connection. This Special Provision is only available with electric supply furnished by Public Service.

(d) **Religious Houses of Worship Service:** Where electric supply is provided by Public Service to a customer where the primary use of service is for public religious services and customer applies for and is eligible for such service, the customer's monthly bill will be subject to a credit of $0.0500 ($0.0533 including SUT) per kilowatt-hour but not to exceed $50.00 ($53.31 including SUT) in any billing period.

The customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Public Service, the customer shall furnish satisfactory proof of eligibility for service under this Special Provision.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 134**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(e) **Unmetered Service:** Unmetered service will be supplied, at the discretion of Public Service, where estimates of kilowatts and kilowatt-hours are based upon information supplied by the customer and agreed to by Public Service. Such estimates of demand and usage shall be constant on a monthly basis.

Unmetered service for automated license plate readers (ALPR) and/or closed-circuit television cameras (CCTV) or similar pole attachments used for body politic-affiliated safety activities may be supplied at the direction of Public Service. Unmetered service to ALPR and CCTV devices shall be based on estimates of kilowatts and kilowatt-hours based upon information supplied by the customer, including any available manufacturer specifications regarding power requirements of these devices. At the discretion of Public Service, the estimates for unmetered service to ALPR or CCTV or similar pole attachment devices may require the assumption that the devices are operate at 100 percent load factor based upon their maximum kilowatt rating.

Customer shall notify Public Service in writing at any time as to changes in conditions or operation of the equipment which may affect estimates of demand or use. Public Service reserves the right to meter any and all such installations where customer does not comply, and customer will no longer be eligible for service under this Special Provision. (See Section 7.1 of the Standard Terms and Conditions.) The customer may be required to furnish and install, at its own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense.

Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.

(f) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(f-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(f-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 135**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(f-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(f-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(f-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (f-3) or (f-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(f-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(g) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 136**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(g-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(g-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(g-2a) A monthly facilities charge as set forth in Section 3.5.2. of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall be used for all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(g-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(g-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 137**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(g-4) **Changes in Duplicate Service Capacity**: Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(h) **Night Use:** Where a customer has requested Public Service to install a time of day meter for billing under this Special Provision, the following shall apply:

(h-1) The Summer Demand Charge will be applicable only to the kilowatts of Day Period Monthly Peak Demand during the months of June through September.

(h-2) A Term of Service on this Special Provision of two years and thereafter until terminated by five days notice.

(h-3) The Day Period shall be considered as the hours of 8 A.M. to 8 P.M. Monday through Friday. All other hours shall be considered the Night Period.

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 138**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(i-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (i-2).

(i-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(i-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(i-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 139**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(i-6) In the event of an emergency condition which occurs outside the period specified in (i-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(j) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(j-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(j-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 140**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(k) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(k-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(k-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(l) Distribution Demand Charge Rebate: A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.

(l-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.

(l-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (l-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.

(l-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.

(l-4) Both new and existing DCFC Charging Locations are eligible for this rebate.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141 for Future**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 142**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages where the customer's measured peak demand exceeds 150 kilowatts in any month and also at primary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES (excluding Direct Current Fast Charging [DCFC] customers):

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.6224	$ 3.8624	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 8.6179	$ 9.1888	per kilowatt of On-Peak Monthly Peak Demand

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES FOR DCFC CUSTOMERS ONLY:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt-hour Charges:

All Use Charge	All Use Charge Including SUT	
$0.XXXXXX	$X.XXXXXX	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 143**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6885	$ 1.8004	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.3731	$ 9.9941	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

	All Use Charge	
Charge	Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 144**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 145**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Basic Generation Service:

A customer's Peak Load Share (PLS), with adjustments, is the basis for the customer's Generation Obligation. A customer's PLS in effect November 1 of a given year will determine the customer's default service type eligibility effective June 1 of the following year [Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) or Basic Generation Service-Commercial and Industrial Pricing (BGS-CIEP)].

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its BGS-RSCP default service for LPL-Secondary customers with a PLS less than 500 kilowatts or BGS-CIEP default service for LPL-Secondary customers with a PLS equal to or greater than 500 kilowatts and LPL-Primary. LPL-Secondary customers with a PLS less than 500 kilowatts may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule LPL for secondary or primary service.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers and during any fifteen-minute interval for primary distribution voltage customers. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands, the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen minute intervals.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 146**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers, and during any fifteen-minute interval for primary distribution voltage customers, that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 147**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Primary Distribution Alternate Service Charge:** Customers taking service at primary distribution voltage, who were billed the under 100 kilowatt Service Charge in July 2003, and whose Monthly Peak Demand has not exceeded 100 kilowatts in any subsequent month shall be subject to a monthly Service Charge of $21.58 ($23.01 including SUT) in lieu of the otherwise applicable Service Charge.

(b) **Substation Service-Individual Customer:** Where special conditions such as location, size or type of load require that customer be supplied at a subtransmission voltage or at high-voltage as designated in Standard Terms and Conditions, Section 4.2., High Voltage Service, and customer and Public Service agree that Public Service will furnish, install, and maintain a substation solely to serve customer from the secondary side of the transformers at nominal voltages of 4,160 volts, 13,200 volts, or 26,400 volts, such service shall be considered as secondary distribution service. Customer may be required to sell or lease a site for the location of the substation. Public Service may require a guaranteed annual payment and a termination agreement.

This provision is closed and is in the process of elimination and is limited to premises presently served under this provision.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 148**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 149**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(e) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges**: Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 150**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 151**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 152**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 153**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(h) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(h-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(h-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 154**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 155**

RATE SCHEDULE HTS
HIGH TENSION SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at subtransmission, transmission and high voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION VOLTAGES:

Service Charge:

$1,911.39 in each month [$2,038.02 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.1442	$ 1.2200	per kilowatt of Annual Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 4.1361	$ 4.4101	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use Charge		
Charge	Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT TRANSMISSION VOLTAGES:

Customers historically served under rate schedule HTS-High Voltage currently receiving service at lower voltage levels on facilities under FERC jurisdiction as a result of system modifications mandated by the Company but have not changed their usage characteristics will continue to be billed as High Voltage customers by having their usage adjusted solely by a factor based upon the current Subtransmission and High Voltage Losses as detailed in the Standard Terms and Conditions, Section 4.3. The current adjustment factor for Subtransmission to High Voltage usage is 1.01212%.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 156**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT HIGH VOLTAGE:

Service Charge:

$1,720.25 in each month [$1,834.22 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 0.6322	$ 0.6741	per kilowatt of Annual Peak Demand

Distribution Kilowatt-hour Charges:

	All Use	
Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION, TRANSMISSION AND HIGH VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage under this rate schedule. This charge shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 157**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Distribution Adjustment Charge, and the CIEP Standby Fee shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service - Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HTS for subtransmission, transmission or high voltage service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 158**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 12. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen-minute intervals. Where traction power is supplied at high voltage (230,000 volts) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining Monthly Peak Demand.

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 159**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Loads Served at 138,000 Volts or Higher:** Customer may be required to supply advance information as to conditions affecting its load as an aid to Public Service in load scheduling. Public Service shall not, without prior written acceptance, be obligated to deliver at a single service location an amount of power in excess of a maximum demand of 50,000 kilowatts at 85% power factor.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 160**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(b) **Termination of Service by Customer:** Where a customer, served at 138,000 volts or higher, terminates service prior to fifteen years from the initial date of service, customer shall be obligated to pay Public Service that part of the total actual cost of any of the 138,000 volt or higher facilities, land, easements, interests, or rights of way used in rendering such service, under the following schedules:

(b-1) Actual cost of facilities through the first year; thence such actual cost reduced by 5% quarterly during the next succeeding year; thence reduced by 1-1/4% quarterly during the next succeeding six years; thence reduced by 1-3/4% quarterly during the next succeeding six years; and then reduced by 2% quarterly during the remaining year.

(b-2) Actual cost of land, easements, interest, or rights of way through the first year; thence at 80% of actual cost during any of the next succeeding nine years; thence reduced by 4% quarterly during the remaining five years.

(b-3) In the event that Public Service determines to serve other load from or otherwise use the aforesaid facilities, lands, easements, interests, or rights of way, then their cost shall be allocated on an equitable basis for the determination of the termination payment reflecting the difference between the actual cost and the allocated cost.

(c) **Resale**: Service under this rate schedule is not available for resale.

(d) **Area Development Service**: Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 110%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 161**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 162**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e) **Duplicate Service:** Where, at request of a subtransmission customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 1.83	$ 1.95	per kilowatt of Duplicate Service Capacity supplied from the same substation or switching station as the Normal Service
$ 2.20	$ 2.35	per kilowatt of Duplicate Service Capacity supplied from a different substation or switching station than the Normal Service

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 163**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 164**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 165**

RATE SCHEDULE HTS

HIGH TENSION SERVICE

(Continued)

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

(h) **Special Provision per Docket No. EO16080788**: This provision of the HTS tariff applies to substation-related service provided to a rail-rapid transit traction power customer that currently subscribes to High Tension Service (HTS) traction power service delivered at 230 kV to an existing multi-substation facility that has been rebuilt by Public Service based upon the approval of the Board of Public Utilities where such approval permits Public Service to own and operate the multi-substation facility and recover the costs of the multi-substation through the traction power customer and distribution rates. In addition, the multi-substation shall provide unique operational characteristics where in disaster or storm events, in which the bulk electric system is inoperable, the multi-substation can operate in isolation to facilitate a microgrid type contingency scheme.

(h-1) The service provided herein shall be the provision of power to a multi- substation facility (meeting the eligibility requirement described herein) owned by Public Service that transforms and delivers power for a traction service HTS customer at voltage levels from 230 kV to 55kV, 27kV, and 12kV. Public Service and the customer will be required to enter into a protocols and operational responsibility agreement that addresses the maintenance and operational responsibilities for the substation. Unless the protocols and operational agreement specifically state otherwise, the terms and conditions of Public Service's tariff shall apply.

(h-2) A customer that is provided this service shall be subject to the requirements of this service tariff as applicable for service delivered at the 230 kV level. All service provided to the substation shall be metered at 230 kV and billed at the 230 kV service rate for traction power service as set forth in the HTS service tariff, except for power delivered to the substation under standard tariff provisions for 13kV which will be billed under the LPL-P tariff.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 166
Original Sheet No. 167
Original Sheet No. 168
Original Sheet No. 169
Original Sheet No. 170
Original Sheet No. 171
Original Sheet No. 172
Original Sheet No. 173
Original Sheet No. 174
Original Sheet No. 175

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 176**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER

APPLICABLE TO:

Electricity produced from a Qualifying Facility as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978, with net capacity no greater than 20 MW and delivered by the Seller to Public Service lines.

RATE:

Service Charge:

$5.00 in each month for installations with a three time period watthour meter, or $30.00 in each month for installations with a recording demand meter.

Energy Payment:

The energy payment in any month for energy received by Public Service shall be based upon the avoided energy cost by time period or by hour, as applicable, in that month (defined as the load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the Public Service Transmission Zone). Historical LMP data may be found on the Pennsylvania-Jersey-Maryland Independent System Operator (PJM) web site at www.pjm.com.

Capacity Payment:

Purchases from a Qualifying Facility that also qualifies as a PJM Installed Capacity Resource, may receive a capacity payment when the capacity exceeds 100 kilowatts and that capacity meets certain reliability criteria as established from time to time by PJM. Capacity payments or charges, if applicable, will be based on the revenue received by Public Service for selling such capacity in the final PJM capacity auction prior to delivery, adjusted for all penalties and other charges assessed to Public Service by PJM related to the non-performance or unavailability of such capacity.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

For any month payment to the Seller shall be the energy payment plus a capacity payment and/or capacity penalties, if applicable, less the Service Charge. Payment to the Seller shall be within approximately 90 days from the customer's meter reading date.

SPECIAL PROVISIONS:

(a) Seller shall pay all connection charges that are incurred by Public Service in excess of the costs for supplying the Qualifying Facility's maximum expected distribution delivery requirements including the costs of any required studies. Such charges may also include charges assessed by PJM.

(b) Seller's installation shall conform to Public Service specifications for interconnections as outlined in the applicable standards, and such installation is also subject to any applicable PJM requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 177**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER
(Continued)

(c) The Seller shall sign an application for Purchased Electric Power.

(d) All Sellers are required to execute an Operations Coordination and Interconnection Agreement with Public Service and comply with all then current PJM generator interconnection and operational standards. Additional information regarding current PJM generator interconnection standards and procedures may be found on the PJM web site at www.pjm.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 178**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 179**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn street lighting and area lighting to a body politic served from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 7.49	$ 7.99
Cobra-Head Cut-Off	50	58	05-0990	8.02	8.55
Post-Top Town & Country	50	58	05-0946, 05-0947	7.35	7.84
Cobra-Head	70	83	05-0927	9.22	9.83
Franklin Park Type V	70	83	05-4054	20.08	21.41
Acorn Decorative	100	117	05-0969	21.13	22.53
Cobra-Head	100	117	05-0940	9.91	10.57
Cobra-Head Cut-Off Type III	100	117	05-0991	15.16	16.16
Deluxe Acorn	100	117	05-0967	19.43	20.72
Franklin Park Type IV	100	117	05-3328	21.87	23.32
Hagerstown Type V	100	130	05-3190	23.06	24.59
New Oxford Black Type III	100	117	05-3260	22.29	23.77
Post-Top Acorn	100	117	05-0963	17.91	19.10
Post-Top Town & Country	100	117	05-0948	11.07	11.80
Post-Top Town & Country	100	117	05-0949	11.67	12.44
Profiler Type III	100	117	05-4593	16.06	17.12
Signature Type V	100	130	05-3210	24.44	26.06
Tear Drop Small Shade B	100	117	05-3338	20.94	22.33
Maplwood Lantern Type III	100	110	05-3300	32.13	34.26
Villager Type III	100	117	05-3373	29.19	31.12
Tear Drop-Small Type III	100	130	05-7097	25.86	27.57
Acorn Decorative	150	177	05-0984	23.25	24.79
Acorn Scroll	150	171	05-0966	25.19	26.86
Architectural Type III	150	190	05-3222	21.56	22.99
Capitol Type V	150	171	05-3202	20.42	21.77
Cobra-Head	150	171	05-0941	10.25	10.93
Cobra-Head Cut-Off Type II	150	171	05-0994	13.91	14.83
Dayform Traditionaire Type III	150	171	05-3415	16.13	17.20
Deluxe Acorn	150	177	05-0968	19.43	20.72
Deluxe Acorn II Type V	150	171	05-3320	17.68	18.85
Edison III Type III	150	177	05-3326	18.80	20.05
Floodlight	150	171	05-0722, 05-0727	13.68	14.59
Franklin Park Type IV	150	171	05-4055	18.91	20.16
Hagerstown Type V	150	190	05-3192, 05-3193	24.65	26.28
Holophane RSL Type V	150	190	05-0931	21.56	22.99
Journal SQ 20" Globe Type V	150	190	05-4050	21.90	23.35
Liberty II Type V	150	171	05-3360	25.91	27.63
Old Boston Lantern Type II	150	171	05-3172	20.67	22.04

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 180**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

High Pressure Sodium (cont'd)	Lamp	Wattage Including	PSE&G Part		Charge Including
Luminaire Type	Wattage	Ballast	Number	Charge	SUT
Post-Top Acorn	150	177	05-0964	$ 18.78	$ 20.02
Post-Top Town & Country	150	171	05-0950	13.76	14.67
Shoe-Box-Small	150	171	05-0971	15.81	16.86
Signature Green Type V	150	171	05-3218	21.93	23.38
Signature Black Type V	150	190	05-3212	25.88	27.59
Trenton Type III	150	190	05-3263	21.58	23.01
Trenton Type V	150	190	05-3268	21.56	22.99
Villager Type III	150	171	05-3176	21.98	23.44
Acorn Scroll	150	171	05-0960	28.34	30.22
Vandal Resistant Type III	150	171	05-3501	14.13	15.07
Cobra-Head	250	300	05-0928	11.83	12.61
Cobra-Head Cut-Off	250	300	05-0993	14.36	15.31
Cobra-Head Vandal Resistant Shield	250	300	05-3502	17.37	18.52
Concourse Type IV	250	300	05-3017	15.13	16.13
Floodlight	250	300	05-0726	16.47	17.56
Shoe-Box-Large	250	300	05-0970	17.54	18.70
Shoe-Box-Small	250	300	05-0973	17.54	18.70
Signature Type V	250	300	05-3379	33.08	35.27
Trenton Type V	250	300	05-3270	18.45	19.67
Cobra-Head	400	450	05-0925	17.77	18.95
Cobra-Head Cut-Off	400	450	05-0929	17.32	18.47
Cobra-Head Type II	400	450	05-0933	17.77	18.95
Expressway Flood	400	450	05-1001	31.00	33.05
Floodlight	400	449	05-0725	21.04	22.43
Floodlight Bronze	400	449	05-0724	21.04	22.43
Shoe-Box-Large	400	470	05-0975	20.07	21.40
Shoe-Box-Small	400	450	05-0979	15.57	16.60
Tear Drop-Large Shade Type III	400	450	05-3336	24.38	26.00
Tear Drop-Large Type III	400	470	05-7096	28.90	30.81
Power Flood	750	839	05-0721	25.49	27.18
Induction					
Cobra-Head Type III	40	40	05-0901	8.89	9.48
Cobra-Head Type III	80	80	05-0902	9.08	9.68
Cobra-Head Type III	150	150	05-0903	12.96	13.82
Cobra-Head Type III	250	260	05-0904	14.50	15.46
Metal Halide					
Hagerstown Green Type V	100	130	05-3196	27.50	29.32
Capitol Black Type V	100	130	05-3206	27.81	29.65
Signature Black Type V	100	130	05-3215	28.27	30.14
Tear Drop – Type V	100	130	05-3281	27.50	29.32
Liberty I Type III	100	130	05-3351	26.57	28.33

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 181**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Standard Luminaires (continued)

Metal Halide (cont'd)	Lamp	Wattage Including	PSE&G Part		Charge Including
Luminaire Type	Wattage	Ballast	Number	Charge	SUT
Granville Black Type III	100	130	05-6038	$ 25.17	$ 26.84
Granville wR&B Type III	100	130	05-6040	25.56	27.25
Granville Type III	100	130	05-6042	25.72	27.42
Hallbrook – Type III	100	130	05-6056	28.99	30.91
Tear Drop – Type III	100	130	05-7102	27.50	29.32
Villager	150	170	05-8060	30.26	32.26
Contempo – Type II	150	170	05-8062	27.16	28.96
Imperial – Type III	150	170	05-8141	28.71	30.61
Hagerstown	150	170	05-8151	27.86	29.71
Capitol Type V	150	170	05-8162	28.71	30.61
Signature Black Type IV	150	165	05-8173	28.71	30.61
Architectural Type III	150	170	05-8181	26.93	28.71
Trenton Type V	150	170	05-8197	25.15	26.82
Tear Drop – Type III	150	170	05-8198	27.86	29.71
Granville Leaf Black Type III	150	170	05-8215	24.34	25.95
Deluxe Acorn	150	170	05-8224	25.38	27.06
Liberty I Type III	150	170	05-8230	26.93	28.71
Villager Type III	150	170	05-8252	30.26	32.26
Franklin Park Type V	150	170	05-8312	27.86	29.71
Pima	150	150	05-8393	26.93	28.71
Techtra – Type V	150	170	05-8441	30.72	32.76
Tear Drop – Type V	150	170	05-8658	27.86	29.71
New London Type III	150	170	05-8190	29.56	31.52
Contempo – Type V	250	280	05-8064	29.89	31.87
Signature Black Type III	250	275	05-8170	29.82	31.80
Tear Drop – Small	250	300	05-8211	28.96	30.88
Tear Drop – Type III	250	280	05-8622	29.12	31.05
Tear Drop – Type III	250	280	05-8664	31.44	33.52
Tear Drop – Large Type V	250	280	05-8668	31.05	33.11
Newarker – Type V	250	280	05-8680	29.82	31.80
Floodlight	320	350	05-8003	12.49	13.32
Cobra – Head Type III	320	350	05-8018	12.65	13.49
Tear Drop - Large Type III	320	350	05-8063	31.53	33.62
LED					
Floodlight	0	140	05-9900	16.31	17.39
Franklin Park	80	90	05-9999	31.86	33.97
Trenton	85	85	05-9930	28.61	30.51
Contempo – Type II	85	90	05-9940	31.55	33.64
Signature	85	100	05-9960	31.63	33.73
Newarker	85	95	05-9970	31.63	33.73
Franklin Park	86	90	05-9920	37.57	40.06
Tear Drop-Large w/Brim	125	90	05-9950	39.53	42.15
Tear Drop-Large	125	129	05-9951	30.47	32.49
Floodlight	129	141	05-0734	12.32	13.14

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 182**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Specialty Luminaires

All luminaires not listed above as Standard Luminaires, all non-standard installations of Standard Luminaires, and any luminaire where the customer makes a contribution toward the total installed cost are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.554% (1.657% including SUT) for all Cobra-Head, Floodlights and Town and Country luminaires, and 1.171% (1.249% including SUT) for all other luminaire types. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable to Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable to All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 183**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
1,000 Lumens NEMA Head	105	105	00-0052	$ 3.87	$ 4.13
2,500 Lumens NEMA Head	205	205	00-0054	5.81	6.19
4,000 Lumens NEMA Head	327	327	00-0055	6.36	6.78
6,000 Lumens NEMA Head	448	448	00-0056	6.43	6.86
10,000 Lumens NEMA Head	690	690	00-0057	5.88	6.27
15,000 Lumens NEMA Head	860	860	00-0058	8.24	8.79
High Pressure Sodium					
Offset Flood	250	300	05-1000	32.31	34.45
Metal Halide					
Hagerstown Black Type V	100	130	05-3195	25.13	26.79
Capitol Type V	175	210	05-3207	27.84	29.68
Hagerstown Type V	175	210	05-3197	27.97	29.82
Holophane GV Type III	175	210	05-3293	25.58	27.27
Old Boston Lantern Type II	175	210	05-3186	28.99	30.91
Post-Top Acorn	175	210	05-0965	19.39	20.67
Signature Type IV & Type V	175	210	05-3217	29.74	31.71
Signature Arch Green	175	210	05-3219	29.74	31.71
Trenton Type V	175	210	05-3272	23.59	25.15
Vero-Green (No Cage)	175	210	05-3545	25.49	27.18
Cobra-Head Vandal Resistant Shield	250	300	05-3503	23.56	25.12
Signature Type V	250	300	05-3213	30.99	33.04
Trenton Type III	250	300	05-3386	27.20	29.00
Cobra-Head Cut-Off	400	460	05-0930	17.58	18.74
Cobra-Head Type III	400	465	05-0916	17.58	18.74
Floodlight	400	460	05-0728	19.46	20.75
Gray Narrow Beam Floodlight	400	460	05-0729	19.46	20.75
Shoe-Box-Large	400	465	05-0976	20.89	22.27
Floodlight	1000	1080	05-0421	26.73	28.50
Mercury Vapor					
Cobra-Head	100	118	05-0921	5.93	6.32
Post-Top Town & Country	100	118	05-0935	5.93	6.32
Post-Top Town & Country Type IV	100	118	05-0936	5.93	6.32
Cobra-Head	175	210	05-0920	7.53	8.03
Post-Top Town & Country	175	210	05-0937	6.00	6.40
Post-Top Town & Country IV	175	210	05-0938	6.00	6.40
Cobra-Head	250	290	05-0919	9.32	9.94
Cobra-Head	400	432	05-0918	10.03	10.69
Floodlight	400	453	05-0422	14.61	15.58
Cobra-Head	1000	1085	05-0768	13.11	13.98
Floodlight	1000	1075	05-0420	23.10	24.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 184**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006894	$ 0.007351

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 185**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL.

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Classic I Black	10 ft.	04-1292	$ 27.39	$ 29.20
Aluminum	Windsor Black	11.5 ft.	04-1269	28.16	30.02
Aluminum	Classic I Black	12 ft.	04-1280	26.37	28.12
Aluminum	Classic I Green	12 ft.	04-1290	29.35	31.29
Aluminum	Colonial Black	12 ft.	04-1264	20.96	22.34
Aluminum	Colonial Fluted Black	12 ft.	04-4036	22.39	23.88
Aluminum	Heritage Black	12 ft.	04-3499	29.95	31.93
Aluminum	Rockford Harbor Fluted Black	12 ft.	04-6015	30.86	32.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 186**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles – Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Westwood Black	12 ft.	04-3260	$24.34	$25.95
Aluminum	Classic II	12 ft.	04-1285	36.35	38.76
Aluminum	Journal Square	12 ft.	04-4059	40.49	43.17
Aluminum	Colonial Fluted Black	13 ft.	04-4440	25.68	27.38
Aluminum	Classic I Black	14 ft.	04-1281	29.24	31.18
Aluminum	Classic I Green	14 ft.	04-1291	27.00	28.79
Aluminum	Classic II Black	14 ft.	04-1286	27.55	29.38
Aluminum	Colgate I Black	14 ft.	04-1262	26.87	28.65
Aluminum	Colonial Fluted Black	14 ft.	04-1261	20.80	22.17
Aluminum	Colonial Round Black	14 ft.	04-1265	21.78	23.22
Aluminum	Heritage Black	14 ft.	04-3500	30.16	32.16
Aluminum	Montclair Black	14 ft.	04-4085	29.44	31.39
Aluminum	Round Black	14 ft.	04-1284	25.66	27.36
Aluminum	Square Bronze	14 ft.	04-1251	18.57	19.80
Aluminum	Heritage Gray	14 ft.	04-3503	39.30	41.90
Aluminum	Classic I Black	14.5 ft.	04-1282	25.90	27.62
Aluminum	Classic II	15 ft.	04-1287	18.68	19.91
Aluminum	Classic I Black	16 ft.	04-1283	27.60	29.43
Aluminum	Colonial Fluted	16 ft.	04-1272	31.19	33.26
Aluminum	Colonial Fluted	16 ft.	04-4084	29.96	31.94
Aluminum	Contemporary Black	16 ft.	04-4073	33.16	35.36
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Hudson Black	16 ft.	04-4083	37.57	40.06
Aluminum	Square Bronze	16 ft.	04-4006	23.80	25.38
Aluminum	Round	18 ft.	04-4017	31.63	33.73
Aluminum	Square 5 inch	20 ft.	04-1257	22.65	24.15
Aluminum	Tall Decorative	20 ft.	04-4091	41.60	44.36
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	26.08	27.81
Aluminum	Octagon Round	25 ft.	04-0198	55.08	58.73
Aluminum	Decorative Black	25 ft.	04-3262	44.26	47.19
Aluminum	Fluted	30 ft.	04-7098	64.33	68.59
Aluminum	Square Black	30 ft.	04-1254	33.29	35.50
Aluminum	Montclair Black	36 ft.	04-4090	36.84	39.28

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 187**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles - Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Square Bronze	30 ft.	04-1250	$ 31.19	$ 33.26
Aluminum	Round	35 ft.	04-1230	27.33	29.14
Cast Aluminum	Colonial Fluted	12 ft.	04-1260	19.94	21.26
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	*8.57	*9.14
Fiberglass	Round Bronze	20 ft.	04-0203	**9.00	**9.60
Fiberglass	Round Bronze	25 ft.	04-0204	19.39	20.67
Laminated Wood	Laminated Wood	30 ft.	04-0225	12.56	13.39
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	14.70	15.67
Pine	Center Bored	30 ft.	04-0350	8.00	8.53
Pine	Round	30 ft.	04-0302	*9.24	*9.85
Pine	Round	35 ft.	04-0304	*10.92	*11.64
Pine	Round Class IV	40 ft.	04-0306	***12.51	***13.34
Pine	Round Class III	45 ft.	04-0308	****13.33	****14.22

***** The charge for indicated poles installed prior to August 1, 2003 is $0.00 ($0.00 including SUT).
****** The charge for indicated poles installed prior to August 1, 2003 is $2.48 ($2.64 including SUT).
******* The charge for indicated poles installed prior to August 1, 2003 is $4.07 ($4.34 including SUT).
******** The charge for indicated poles installed prior to August 1, 2003 is $6.79 ($7.24 including SUT).

Specialty Lighting Poles and Miscellaneous Devices:

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, any pole where the customer makes a contribution toward the total installed cost, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.097% (1.170% including SUT). This Capital Recovery Charge shall remain unchanged over the remaining life of the pole. In underground zones the total installed cost excludes the cost of underground conduits, conductors, manholes and handholes, but includes the cost of equivalent overhead conductors.

(2) A Maintenance Charge that varies by item type and is equal to the following:

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 188**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 189**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Five years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs net of any customer contribution.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable whether or not due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement. Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) Underground Construction:

(b-1) Underground construction will be provided at no additional charge in underground zones designated by Public Service for all public street lighting applications and for nonpublic street lighting applications up to 100 feet distant from the public street as measured at right angles to the curb. Where underground construction is desired for all other applications and in other areas, the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes.

(b-2) In a underground zone designated by Public Service, a standard 30 foot aluminum street lighting pole, or credit equivalent, will be provided for each luminaire utilized for public street lighting by a body politic at no charge. The installation of these poles will be provided with a minimum space between poles of 150 feet when measured along the curb line.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 190**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(b-3) In subdivisions subject to the Regulations for Residential Electric Underground Extensions in N.J.A.C. 14:3-8 et seq., there will be no monthly charge to the local municipality for standard street lighting poles utilized for public street lighting that have been included in the charges paid by the developer of the subdivision as determined under tariff section Regulation for Residential Underground Extension.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

Body Politic customers may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Miscellaneous Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 191**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 192
Original Sheet No. 193
Original Sheet No. 194

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 195**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

APPLICABLE TO USE OF SERVICE FOR:

This rate class is closed and in the process of elimination. Firm delivery service and maintenance for dusk to dawn street lighting and area lighting to a body politic served from Publicly-Owned Lighting Facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

MAINTENANCE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 1.87	$ 1.99
Cobra-Head Cut-Off Type IV	50	58	05-0990	1.87	1.99
Post-Top Town & Country	50	58	05-0946	1.87	1.99
Cobra-Head	100	117	05-0940	1.87	1.99
Post-Top Town & Country II	100	117	05-0948	1.87	1.99
Post-Top Town & Country IV	100	117	05-0949	1.87	1.99
Cobra-Head	150	171	05-0941	1.87	1.99
Post-Top Acorn	150	171	05-0964	2.61	2.78
Post-Top Town & Country II	150	171	05-0950	1.87	1.99
Shoe-Box-Large Round	150	171	05-0971	2.61	2.78
Shoe-Box-Large Square	150	171	05-0971	2.61	2.78
Cobra-Head	250	300	05-0928	1.87	1.99
Cobra-Head Cut-Off	250	300	05-0993	1.87	1.99
Shoe-Box-Large	250	300	05-0970	2.61	2.78
Shoe-Box-Large Round	250	300	05-0970	2.61	2.78
Shoe-Box-Large Square	250	300	05-0970	2.61	2.78
Cobra-Head Vandal Resistant Shield	250	300	05-3502	1.87	1.99
Cobra-Head	400	450	05-0925	1.87	1.99
Cobra-Head Cut-Off	400	450	05-0929	1.87	1.99
Shoe-Box-Large	400	470	05-0975	2.61	2.78

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 196**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	N/A	$ 5.38	$ 5.74
1,000 Lumens NEMA Head	105	105	N/A	5.38	5.74
2,500 Lumens NEMA Head	205	205	N/A	5.38	5.74
4,000 Lumens NEMA Head	327	327	N/A	5.38	5.74
6,000 Lumens NEMA Head	448	448	N/A	5.38	5.74
10,000 Lumens NEMA Head	690	690	N/A	5.38	5.74
Metal Halide					
Acorn	175	210	N/A	4.06	4.33
Floodlight	1000	1080	N/A	6.11	6.51
Mercury Vapor					
Cobra-Head	175	210	N/A	1.08	1.15
Post-Top Town & Country Type IV	175	210	N/A	0.59	0.63
Cobra-Head	250	290	N/A	0.59	0.63
Cobra-Head	400	432	N/A	0.59	0.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 197**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006931	$ 0.007390

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 198**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL-POF.

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 199**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

One year for all new lamps and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service from Publicly-Owned Facilities:** Service under this Rate Schedule is only available where Public Service has paid no part of the cost of the distribution facilities, lamps, luminaires and all other associated equipment beyond the point of connection to the Public Service distribution system, such point of connection to be designated by Public Service. The complete lighting installation shall meet with the approval of Public Service for operation and maintenance. Public Service will clean refractors or globes, replace lamps, locate cable faults and make minor cable and socket repairs. Replacement of defective cable, painting or otherwise maintaining posts or luminaires or any other associated equipment shall be done only at the expense of the customer. In the event of repeated damage to the equipment, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 200**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

(b) **Service to Indicating Lamps:** Service to indicating lamps used for marking location of fire and police boxes, fixed warning or obstruction lights, or similar purposes will be provided where all necessary materials and labor for indicating lamp installations is furnished and installed by and at the expense of the customer. Service to indicating lamps will be furnished only if practicable and safe from the standpoint of Public Service.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 201
Original Sheet No. 202

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 203**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn private street lighting and outdoor area lighting from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 8.72	$ 9.30
Cobra-Head Cut-Off	50	58	05-0990	9.34	9.95
Dayform Traditionaire Type III	50	58	05-3410	24.03	25.62
Post-Top Town & Country	50	58	05-0946	8.72	9.30
Post-Top Town & Country Black Type V	50	58	05-0947	8.72	9.30
Cobra-Head	70	83	05-0927	10.76	11.47
Traditional Bollard Type V	70	83	05-3400	23.12	24.65
Capitol Type V	100	130	05-3200	26.92	28.71
Cobra-Head Cut-Off Type III	100	117	05-0991	21.03	22.43
Cobra-Head	100	117	05-0940	12.86	13.71
Dayform Traditionaire Type III	100	117	05-3412	25.73	27.44
Deluxe Acorn	100	117	05-0967	22.55	24.05
Granville Black Type III	100	117	05-6037	27.88	29.73
Post-Top Acorn	100	117	05-0963	20.93	22.31
Post-Top Town & Country	100	117	05-0948	12.98	13.84
Post-Top Town & Country Type IV	100	117	05-0949	13.73	14.64
Profiler Type III	100	117	05-4593	21.69	23.13
Architectural Type III	150	190	05-3222	25.26	26.93
Cobra-Head	150	171	05-0941	13.16	14.03
Dayform Traditionaire Type III	150	171	05-3415	21.99	23.44
Dayform Traditionaire Type V	150	171	05-3317	27.17	28.97
Deluxe Acorn	150	177	05-0968	22.55	24.05
Edison III Type III	150	177	05-3326	26.88	28.66
Floodlight	150	171	05-0722, 05-0727	16.16	17.23
Franklin Park Type IV	150	177	05-4055	27.41	29.22
Old Boston Type V	150	171	05-0995	22.06	23.52
Post-Top Acorn	150	177	05-0964	22.04	23.50
Post-Top Town & Country	150	171	05-0950	16.10	17.16
Richmond Black Type III	150	177	05-4328	27.08	28.87
Shoe-Box-Small	150	171	05-0971	18.58	19.81
Signature Type V	150	171	05-3212	27.99	29.84
Trenton Type III	150	190	05-3263	25.26	26.93
Trenton Type V	150	177	05-3268	23.84	25.42
Hagerstown Type V	150	171	05-3192	33.45	35.67
Swan – Type V	150	177	05-4103	31.33	33.41
Cobra-Head	250	300	05-0928	14.43	15.39
Cobra-Head Cut-Off	250	300	05-0993	17.63	18.80
Floodlight	250	300	05-0723, 05-0726	19.60	20.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 204**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Standard Luminaires (continued)

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
High Pressure Sodium (cont'd)					
Shoe-Box-Large	250	300	05-0970	$ 20.79	$ 22.17
Shoe-Box-Small	250	300	05-0973	20.79	22.17
Cobra-Head	400	450	05-0925	21.32	22.73
Cobra-Head Cut-Off	400	450	05-0929	20.75	22.13
Concourse Type III	400	450	05-3018	32.77	34.94
Expressway Flood	400	450	05-1001	36.63	39.06
Floodlight	400	449	05-0724,05-0725	26.32	28.06
Galleria Type AS	400	465	05-3111	32.02	34.15
Shoe Box-Large	400	470	05-0975	24.04	25.63
Shoe-Box-Small	400	450	05-0979	23.98	25.57
Power Flood	750	839	05-0721	34.02	36.27
Induction					
Cobra-Head Type III	40	40	05-0901	11.78	12.57
Cobra-Head Type III	80	80	05-0902	13.19	14.06
Cobra-Head Type III	150	150	05-0903	18.06	19.26
Cobra-Head Type III	250	260	05-0904	21.82	23.26
Metal Halide					
Signature Black Type V	100	130	05-3215	35.14	37.47
Classic Bollard	100	130	05-3423	41.08	43.80
Granville Black Type III	100	130	05-6038	31.29	33.36
Franklin Park Type V	150	170	05-8312	34.63	36.92
Hagarstown w/Cutoff	150	190	05-8316	36.18	38.58
Tear Drop - Type III	250	280	05-8664	38.90	41.48
Floodlight	320	350	05-8003	15.45	16.47
Cobra-Head Type III	320	350	05-8018	15.66	16.70
Profiler Type III	320	350	05-8550	28.55	30.44
LED					
Floodlight	0	140	05-9900	20.95	22.34
Floodlight	129	141	05-0734	15.97	17.03
Ecoform – Type III	158	173	05-6033	26.67	28.44

Specialty Luminaires

All luminaires not listed above as Standard Luminaires and all non-standard installations of Standard Luminaires are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 2.004% (2.137% including SUT) for all Cobrahead, Floodlights and Town and Country luminaires, and 1.634% (1.742% including SUT) for all other luminaire types. Customers requesting installation of lighting facilities related to construction

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 205**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires. These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable To Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable To All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 206**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	00-0081	$ 4.42	$ 4.71
1,000 Lumens NEMA Head	105	105	00-0083	4.63	4.94
2,500 Lumens NEMA Head	205	205	00-0084	7.04	7.50
4,000 Lumens NEMA Head	327	327	00-0085	7.87	8.39
6,000 Lumens NEMA Head	448	448	00-0086	8.15	8.69
10,000 Lumens NEMA Head	690	690	00-0087	7.94	8.47
15,000 Lumens NEMA Head	860	860	00-0088	10.93	11.65
High Pressure Sodium					
Offset Flood	250	300	05-1000	36.84	39.28
Metal Halide					
Vandal Resistant Bollard Type V	100	130	05-3409	29.07	30.99
Bishop Crook	175	210	05-0911	36.42	38.83
Hagarstown w/ Cut-Off Type V	175	210	05-4072	37.65	40.15
Hagerstown Type V	175	210	05-3197	32.22	34.35
Manor Lantern Type III	175	210	05-3615	33.39	35.60
Post Top Acorn	175	210	05-0965	22.52	24.01
Signature Type IV & Type V	175	210	05-3217	34.22	36.49
Cobra Head Cut-Off	400	460	05-0930	21.17	22.57
Floodlight	400	460	05-0728	23.37	24.91
Gray Narrow Beam Floodlight	400	460	05-0729	23.37	24.91
Profiler Type III	400	465	05-5025	33.20	35.40
Shoe-Box-Large	400	465	05-0976	24.91	26.56
Floodlight	1000	1080	05-0421	31.89	34.00
Mercury Vapor					
Cobra-Head	100	118	05-0921	6.98	7.44
Post-Top Town & Country	100	118	05-0935	6.98	7.44
Post-Top Town & Country Type IV	100	118	05-0936	6.98	7.44
Cobra-Head	175	210	05-0920	8.99	9.59
Post-Top Town & Country	175	210	05-0937	8.03	8.56
Post-Top Town & Country Type IV	175	210	05-0938	8.03	8.56
Cobra-Head	250	290	05-0919	11.20	11.94
Cobra-Head	400	432	05-0918	12.50	13.33
Floodlight	400	453	05-0422	17.68	18.85
Cobra-Head	1000	1085	05-0768	17.12	18.26
Floodlight	1000	1075	05-0420	28.67	30.57

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 207**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.007355	$ 0.007842

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 208**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

For unmetered lighting, the BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule PSAL.

For lighting and all other associated equipment in which Public Service has determined metering is required, the electric supply charges will be charged under Rate Schedule General Lighting and Power (GLP). The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 209**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Windsor Black	11.5 ft.	04-1269	$ 31.26	$ 33.33
Aluminum	Classic I Black	12 ft.	04-1280	31.79	33.90
Aluminum	Classic II	12 ft.	04-1285	30.81	32.85
Aluminum	Colonial Fluted	12 ft.	04-1260	25.18	26.85
Aluminum	Contemporary Black	12 ft.	04-0353	30.77	32.81
Aluminum	Montclair Black	12 ft.	04-1273	34.75	37.05
Aluminum	Wadsworth Black	12 ft.	04-6011	26.35	28.09
Aluminum	Westwood Black	12 ft.	04-3260	24.34	25.95
Aluminum	Classic I Black	14 ft.	04-1281	32.04	34.17
Aluminum	Classic II Black	14 ft.	04-1286	32.73	34.90
Aluminum	Colgate I Black	14 ft.	04-1262	35.55	37.90
Aluminum	Colonial Fluted Black	14 ft.	04-1261	26.29	28.03
Aluminum	Colonial Round Black	14 ft.	04-1265	26.66	28.43
Aluminum	Heritage Black	14 ft.	04-3500	32.72	34.88
Aluminum	Square 5 inch	14 ft.	04-1256	27.35	29.16
Aluminum	Square Bronze	14 ft.	04-1251	22.29	23.77
Aluminum	Wadsworth Black	14 ft.	04-6009	26.78	28.55
Aluminum	Colonial Fluted	16 ft.	04-4084	34.14	36.40
Aluminum	Contemporary Black	16 ft.	04-4073	35.55	37.90
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Square 5 inch	20 ft.	04-1257	28.66	30.56
Aluminum	Square Bronze	20 ft.	04-1252	24.21	25.82
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	33.07	35.26
Aluminum	Square Green 5 inch	25 ft.	04-5025	32.25	34.39
Aluminum	Square Bronze	30 ft.	04-1250	38.96	41.54
Aluminum	Round	35 ft.	04-1230	34.17	36.43
Aluminum	Colonial Fluted	10 ft.	04-1247	19.43	20.72
Aluminum	Classic 1 Black	14.5 ft.	04-1282	35.79	38.16
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	8.57	9.14
Fiberglass	Round Bronze	20 ft.	04-0203	10.67	11.38
Fiberglass	Smooth Tapered Black	20 ft.	04-0205	31.66	33.76
Fiberglass	Round Bronze	25 ft.	04-0204	12.61	13.45
Laminated Wood	Natural	25 ft.	04-0195	13.25	14.13
Laminated Wood	Laminated Wood	30 ft.	04-0225	18.64	19.88
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	21.76	23.20
Pine	Center Bored	30 ft.	04-0350	17.25	18.40
Pine	Round	30 ft.	04-0302	9.24	9.85
Pine	Round	35 ft.	04-0304	10.92	11.64
Pine	Round Class IV	40 ft.	04-0306	13.96	14.88
Pine	Round Class III	45 ft.	04-0308	16.75	17.86

(Charges are for illustrative purposes only see Streetlight Appendix)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 210**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Specialty Lighting Poles and Miscellaneous Devices

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 1.635% (1.743% including SUT). Customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Lighting Poles and Miscellaneous Devices.

These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the pole.

(2) A Maintenance Charge that varies by item type and is equal to the following*:

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

* Maintenance Charges for poles and devices that are not otherwise described in (2) above, shall be determined by the Company on a case by case basis.

BILLING DETERMINANTS FOR UNMETERED LIGHTING:

Kilowatt-hours:

For lighting and all other associated equipment in which demand and usage are constant on a monthly basis, estimates of kilowatts and kilowatt-hours will be utilized. The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

For lighting and all other associated equipment in which demand and usage are not constant on a monthly basis, the service will be metered and billed under Rate Schedule GLP unless Public Service at its sole discretion determines otherwise.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 211**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Generation Obligation:

For unmetered service, the customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

For unmetered service, the customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 212**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice, unless underground construction is utilized, where the term shall be five years and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Ten years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs; for facilities removed from the fifth to tenth year after installation such payment shall equal the cost of removal less salvage plus 50% of the original installed costs.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) **Underground Construction:** Where underground construction is desired the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes. In designated underground zones, up to 100 feet of underground secondary service facilities as measured at right angles to the curb to the nearest pole utilized for lighting service under this Rate Schedule shall be exempt from this provision and will be provided by Public Service at no charge.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 213**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

PSAL customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a Body Politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Maintenance Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 214**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(h) **Metered Service:** Usage based charges for lighting and all other associated equipment in which Public Service has determined metering is required will be served under Rate Schedule General Lighting and Power (GLP). Associated luminaire and maintenance charges will continue to be served under this rate schedule. The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

BPL Proposed Standard Luminaire Charges

Tariff Status	Light Source	Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
Standard (Open)	LED	Cobra Head	20	22	05-3438	$7.90	**$8.42**
Standard (Open)	LED	Cobra Head	36	39	05-3285	$11.46	**$12.22**
Standard (Open)	LED	Cobra Head	56	62	05-3286	$11.90	**$12.69**
Standard (Open)	LED	Cobra Head	73	81	05-3287	$12.56	**$13.39**
Standard (Open)	LED	Cobra Head	107	118	05-3288	$16.90	**$18.02**
Standard (Open)	LED	Cobra Head	180	199	05-3289	$18.70	**$19.94**
Standard (Open)	LED	Floodlight	85	90	05-4090	$10.66	**$11.37**
Standard (Open)	LED	Floodlight	129	140	05-4091	$11.55	**$12.32**
Standard (Open)	LED	Floodlight	266	292	05-1091	$18.40	**$19.62**
Standard (Open)	LED	Town & Country	12	15	05-0905	$21.69	**$23.13**
Standard (Open)	LED	Town & Country	39	43	05-0906	$21.69	**$23.13**
Standard (Open)	LED	Town & Country	64	71	05-0907	$21.84	**$23.29**
Standard (Open)	LED	Traditionaire	23	27	05-3434	$23.15	**$24.68**
Standard (Open)	LED	Traditionaire	46	51	05-3435	$23.15	**$24.68**
Standard (Open)	LED	Traditionaire	77	85	05-3436	$23.15	**$24.68**
Standard (Open)	LED	Shoebox	100	110	05-3165	$19.44	**$20.72**
Standard (Open)	LED	Shoebox	130	145	05-3166	$20.57	**$21.93**
Standard (Open)	LED	Shoebox	160	180	05-3167	$20.93	**$22.32**
Open	LED	NEMA Head	20	25	05-9952	$9.68	**$10.32**
Open	LED	NEMA Head Cobra	20	30	05-9953	$9.73	**$10.37**
Open	LED	PIMA Black T-5	52	56	05-4098	$33.59	**$35.82**
Open	LED	Roadway With Brim	58	60	05-9990	$7.45	**$7.94**
Open	LED	Tear Drop Black	75	84	05-7200	$34.90	**$37.21**
Open	LED	Trenton	85	85	05-9930	$28.73	**$30.63**
Open	LED	Franklin Park	80	90	05-9999	$31.99	**$34.11**
Open	LED	Contempo - Type II	85	90	05-9940	$31.68	**$33.78**
Open	LED	Franklin Park	86	90	05-9920	$37.73	**$40.23**
Open	LED	Tear Drop-Large w/ Brim	125	90	05-9950	$39.69	**$42.32**
Open	LED	PIMA	80	87	05-4082	$22.17	**$23.64**
Open	LED	Deluxe Acorn Black	85	94	05-4071	$22.26	**$23.73**
Open	LED	Newarker	85	95	05-9970	$31.76	**$33.86**
Open	LED	Signature Black T-3	88	95	05-3211	$34.98	**$37.30**
Open	LED	Signature	85	100	05-9960	$31.76	**$33.86**
Open	LED	Tear Drop-Large	125	129	05-9951	$30.58	**$32.61**
Open	LED	Floodlight	0	141	05-9900	$16.35	**$17.43**
Open	LED	Floodlight	129	141	05-0734	$12.34	**$13.16**
Open	LED	Ecoform Black	158	173	05-6031	$23.54	**$25.10**
Open	LED	Ecoform - Type III	158	173	05-6033	$24.05	**$25.64**
Open	LED	Floodlight	266	292	05-1095	$18.40	**$19.62**
Open	LED	Floodlight	363	400	05-0423	$17.79	**$18.97**
Closed	FLU	Fluorescent	400	510	00-0102	$16.33	**$17.41**
Closed	HPS	Cobra-Head	50	58	05-0926	$9.72	**$10.36**
Closed	HPS	Cobra-Head Cut-Off	50	58	05-0990	$8.24	**$8.79**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$19.98	**$21.30**
Closed	HPS	Post-Top Town & Country Black Type V	50	58	05-0947	$19.98	**$21.30**
Closed	HPS	Cobra-Head	70	83	05-0927	$9.77	**$10.42**
Closed	HPS	Franklin Park Type V	70	83	05-4054	$20.61	**$21.98**
Closed	HPS	Maplwood Lantern Type III	100	110	05-3300	$32.26	**$34.40**
Closed	HPS	Acorn Decorative	100	117	05-0969	$21.20	**$22.60**
Closed	HPS	Cobra-Head	100	117	05-0940	$10.54	**$11.24**
Closed	HPS	Cobra Head Cut-Off Type III	100	117	05-0991	$15.52	**$16.55**
Closed	HPS	Deluxe Acorn	100	117	05-0967	$19.96	**$21.28**
Closed	HPS	Franklin Park Type IV	100	117	05-3328	$21.940	**$23.39**
Closed	HPS	New Oxford Black Type III	100	117	05-3260	$22.37	**$23.85**
Closed	HPS	Post-Top Acorn	100	117	05-0963	$18.27	**$19.48**
Closed	HPS	Post-Top Town & Country	100	117	05-0948	$11.39	**$12.14**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$12.00	**$12.80**
Closed	HPS	Profiler Type III	100	117	05-4593	$16.11	**$17.18**
Closed	HPS	Tear Drop Small Shade B	100	117	05-3338	$21.01	**$22.40**
Closed	HPS	Villager Type III	100	117	05-3373	$29.30	**$31.24**
Closed	HPS	Hagerstown Type V	100	130	05-3190	$23.140	**$24.67**
Closed	HPS	Signature Type V	100	130	05-3210	$24.52	**$26.14**
Closed	HPS	Tear Drop-Small Type III	100	130	05-7097	$25.95	**$27.67**
Closed	HPS	Acorn Scroll	150	171	05-0966	$25.27	**$26.94**

BPL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Capitol Type V	150	171	05-3202	$20.99	**$22.38**
Closed	HPS	Cobra-Head	150	171	05-0941	$11.03	**$11.76**
Closed	HPS	Cobra-Head Cut-Off Type II	150	171	05-0994	$13.93	**$14.85**
Closed	HPS	Dayform Traditionaire Type III	150	171	05-3415	$19.86	**$21.18**
Closed	HPS	Deluxe Acorn II Type V	150	171	05-3320	$18.18	**$19.38**
Closed	HPS	Floodlight	150	171	05-0722	$13.70	**$14.61**
Closed	HPS	Floodlight	150	171	05-0727	$13.70	**$14.61**
Closed	HPS	Franklin Park Type IV	150	171	05-4055	$19.45	**$20.74**
Closed	HPS	Liberty II Type V	150	171	05-3360	$25.99	**$27.71**
Closed	HPS	Old Boston Lantern Type II	150	171	05-3172	$21.25	**$22.66**
Closed	HPS	Post-Top Town & Country	150	171	05-0950	$14.16	**$15.10**
Closed	HPS	Shoe-Box-Small	150	171	05-0971	$16.26	**$17.34**
Closed	HPS	Signature Green Type V	150	171	05-3218	$22.54	**$24.03**
Closed	HPS	Villager Type III	150	171	05-3176	$22.59	**$24.09**
Closed	HPS	Acorn Scroll	150	171	05-0960	$28.43	**$30.31**
Closed	HPS	Vandal Resistant Type III	150	171	05-3501	$14.15	**$15.09**
Closed	HPS	Acorn Decorative	150	177	05-0984	$23.31	**$24.85**
Closed	HPS	Deluxe Acorn	150	177	05-0968	$19.98	**$21.30**
Closed	HPS	Edison III Type III	150	177	05-3326	$18.84	**$20.09**
Closed	HPS	Post-Top Acorn	150	177	05-0964	$18.82	**$20.07**
Closed	HPS	Architectural Type III	150	190	05-3222	$21.61	**$23.04**
Closed	HPS	Hagerstown Type V	150	190	05-3192	$24.72	**$26.36**
Closed	HPS	Hagarstown Type V	150	190	05-3193	$24.72	**$26.36**
Closed	HPS	Holophane RSL Type V	150	190	05-0931	$21.61	**$23.04**
Closed	HPS	Journal SQ 20" Globe Type V	150	190	05-4050	$22.48	**$23.97**
Closed	HPS	Signature Type V	150	190	05-3212	$25.95	**$27.67**
Closed	HPS	Trenton Type III	150	190	05-3263	$21.63	**$23.06**
Closed	HPS	Trenton Type V	150	190	05-3268	$21.61	**$23.04**
Closed	HPS	Cobra-Head	250	300	05-0928	$11.83	**$12.61**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$14.36	**$15.31**
Closed	HPS	Cobra-Head Vandal Resistant Shield	250	300	05-3502	$17.37	**$18.52**
Closed	HPS	Concourse Type IV	250	300	05-3017	$15.61	**$16.64**
Closed	HPS	Floodlight	250	300	05-0726	$16.47	**$17.56**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$19.78	**$21.09**
Closed	HPS	Shoe-Box-Small	250	300	05-0973	$17.54	**$18.70**
Closed	HPS	Signature Type V	250	300	05-3379	$33.16	**$35.36**
Closed	HPS	Trenton Type V	250	300	05-3270	$18.45	**$19.67**
Closed	HPS	Offset Flood	250	300	05-1000	$33.22	**$35.42**
Closed	HPS	Floodlight	400	449	05-0725	$21.04	**$22.43**
Closed	HPS	Floodlight Bronze	400	449	05-0724	$21.04	**$22.43**
Closed	HPS	Cobra-Head	400	450	05-0925	$17.77	**$18.95**
Closed	HPS	Cobra-Head Cut-Off	400	450	05-0929	$17.32	**$18.47**
Closed	HPS	Cobra-Head Type II	400	450	05-0933	$17.77	**$18.95**
Closed	HPS	Expressway Flood	400	450	05-1001	$31.02	**$33.08**
Closed	HPS	Shoe-Box-Small	400	450	05-0979	$16.12	**$17.19**
Closed	HPS	Tear Drop-Large Shade Type III	400	450	05-3336	$25.15	**$26.82**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$20.07	**$21.40**
Closed	HPS	Tear Drop-Large Type III	400	470	05-7096	$28.91	**$30.83**
Closed	HPS	Power Flood	750	839	05-0721	$25.49	**$27.18**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0052	$6.99	**$7.45**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0054	$7.53	**$8.03**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0055	$7.53	**$8.03**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0056	$7.53	**$8.03**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0057	$7.53	**$8.03**
Closed	INC	15,000 Lumens NEMA Head	860	860	00-0058	$8.74	**$9.32**
Closed	IND	Cobra-Head Type III	40	40	05-0901	$10.41	**$11.10**
Closed	IND	Cobra-Head Type III	80	80	05-0902	$11.15	**$11.89**
Closed	IND	Cobra-Head Type III	150	150	05-0903	$12.98	**$13.84**
Closed	IND	Cobra-Head Type III	250	260	05-0904	$14.50	**$15.46**
Closed	MH	Hagerstown Green Type V	100	130	05-3196	$27.60	**$29.43**
Closed	MH	Capitol Black Type V	100	130	05-3206	$27.91	**$29.76**
Closed	MH	Signature Black Type V	100	130	05-3215	$28.37	**$30.25**
Closed	MH	Tear Drop - Type V	100	130	05-3281	$27.60	**$29.43**
Closed	MH	Liberty I Type III	100	130	05-3351	$26.66	**$28.43**
Closed	MH	Granville Black Type III	100	130	05-6038	$25.26	**$26.93**

BPL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	MH	Granville w R&B Type III	100	130	05-6040	$25.65	**$27.35**
Closed	MH	Granville Typre III	100	130	05-6042	$25.81	**$27.52**
Closed	MH	Hallbrook - Type III	100	130	05-6056	$29.10	**$31.03**
Closed	MH	Tear Drop - Type III	100	130	05-7102	$27.60	**$29.43**
Closed	MH	Hagerstown Black Type V	100	130	05-3195	$25.80	**$27.51**
Closed	MH	Pima	150	150	05-8393	$27.02	**$28.81**
Closed	MH	Signature Black Type IV	150	165	05-8173	$28.81	**$30.72**
Closed	MH	Villager	150	170	05-8060	$30.36	**$32.37**
Closed	MH	Contempo - Type II	150	170	05-8062	$27.25	**$29.06**
Closed	MH	Imperial - Type III	150	170	05-8141	$28.80	**$30.71**
Closed	MH	Hagerstown	150	170	05-8151	$27.95	**$29.80**
Closed	MH	Capitol Type V	150	170	05-8162	$28.81	**$30.72**
Closed	MH	Architectural Type III	150	170	05-8181	$27.02	**$28.81**
Closed	MH	Trenton Type V	150	170	05-8197	$25.23	**$26.90**
Closed	MH	Tear Drop - Type III	150	170	05-8198	$27.95	**$29.80**
Closed	MH	Granville Leaf Black Type III	150	170	05-8215	$24.41	**$26.03**
Closed	MH	Deluxe Acorn	150	170	05-8224	$25.46	**$27.15**
Closed	MH	Liberty I Type III	150	170	05-8230	$27.02	**$28.81**
Closed	MH	Villager Type III	150	170	05-8252	$30.36	**$32.37**
Closed	MH	Franklin Park Type V	150	170	05-8312	$27.95	**$29.80**
Closed	MH	Techtra - Type V	150	170	05-8441	$30.83	**$32.87**
Closed	MH	Tear Drop - Type V	150	170	05-8658	$27.95	**$29.80**
Closed	MH	New London Type III	150	170	05-8190	$29.66	**$31.62**
Closed	MH	Capitol Type V	175	210	05-3207	$28.61	**$30.51**
Closed	MH	Hagerstown Type V	175	210	05-3197	$28.74	**$30.64**
Closed	MH	Holophane GV Type III	175	210	05-3293	$26.29	**$28.03**
Closed	MH	Old Boston Lantern Type II	175	210	05-3186	$29.79	**$31.76**
Closed	MH	Post-Top Acorn	175	210	05-0965	$19.95	**$21.27**
Closed	MH	Signature Type IV & Type V	175	210	05-3217	$30.55	**$32.57**
Closed	MH	Signature-Arch Green	175	210	05-3219	$30.55	**$32.57**
Closed	MH	Trenton Type V	175	210	05-3272	$24.25	**$25.86**
Closed	MH	Vero-Green (No Cage)	175	210	05-3545	$26.20	**$27.94**
Closed	MH	Signature Black Type III	250	275	05-8170	$29.89	**$31.87**
Closed	MH	Contempo - Type V	250	280	05-8064	$29.96	**$31.94**
Closed	MH	Tear Drop - Type III	250	280	05-8622	$29.18	**$31.11**
Closed	MH	Tear Drop - Type III	250	280	05-8664	$31.51	**$33.60**
Closed	MH	Tear Drop-Large Type V	250	280	05-8668	$31.12	**$33.18**
Closed	MH	Newarker - Type V	250	280	05-8680	$29.89	**$31.87**
Closed	MH	Tear Drop-Small	250	300	05-8211	$29.06	**$30.99**
Closed	MH	Cobra-Head Vandal Resistant Shield	250	300	05-3503	$24.25	**$25.86**
Closed	MH	Signature Type V	250	300	05-3213	$31.87	**$33.98**
Closed	MH	Trenton Type III	250	300	05-3386	$27.98	**$29.83**
Closed	MH	Floodlight	320	350	05-8003	$12.49	**$13.32**
Closed	MH	Cobra-Head Type III	320	350	05-8018	$13.67	**$14.58**
Closed	MH	Tear Drop-Large Type III	320	350	05-8063	$31.58	**$33.67**
Closed	MH	Cobra-Head Cut-Off	400	460	05-0930	$26.11	**$27.84**
Closed	MH	Floodlight	400	460	05-0728	$20.10	**$21.43**
Closed	MH	Gray Narrow Beam Floodlight	400	460	05-0729	$20.10	**$21.43**
Closed	MH	Cobra-Head Type III	400	465	05-0916	$18.18	**$19.38**
Closed	MH	Shoe-Box-Large	400	465	05-0976	$21.57	**$23.00**
Closed	MH	Floodlight	1000	1080	05-0421	$27.76	**$29.60**
Closed	MV	Cobra-Head	100	118	05-0921	$9.94	**$10.60**
Closed	MV	Post-Top Town & Country	100	118	05-0935	$18.98	**$20.24**
Closed	MV	Post-Top Town & Country Type IV	100	118	05-0936	$18.98	**$20.24**
Closed	MV	Cobra-Head	175	210	05-0920	$9.94	**$10.60**
Closed	MV	Post-Top Town & Country	175	210	05-0937	$16.90	**$18.02**
Closed	MV	Post-Top Town & Country Type IV	175	210	05-0938	$16.90	**$18.02**
Closed	MV	Cobra-Head	250	290	05-0919	$12.18	**$12.99**
Closed	MV	Cobra-Head	400	432	05-0918	$10.43	**$11.12**
Closed	MV	Floodlight	400	453	05-0422	$15.13	**$16.13**
Closed	MV	Floodlight	1000	1075	05-0420	$24.04	**$25.63**
Closed	MV	Cobra-Head	1000	1085	05-0768	$13.81	**$14.72**

BPL-POF Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Cobra-Head	50	58	05-0926	$2.27	**$2.42**
Closed	HPS	Cobra-Head	50	58	05-0990	$2.27	**$2.42**
Closed	HPS	Cobra-Head Cut-Off Type IV	50	58	05-0990	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$2.27	**$2.42**
Closed	HPS	Cobra-Head	100	117	05-0940	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type II	100	117	05-0948	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$2.27	**$2.42**
Closed	HPS	Cobra-Head	150	171	05-0941	$2.27	**$2.42**
Closed	HPS	Cobra-Head	150	171	05-0926	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type II	150	171	05-0950	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large Square	150	171	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large Round	150	171	05-0970	$3.15	**$3.36**
Closed	HPS	Cobra-Head	250	300	05-0928	$2.27	**$2.42**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large Round	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Vandal Resistant	250	300	05-3502	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large	400	450	05-0975	$3.15	**$3.36**
Closed	INC	600 Lumens NEMA Head	58	58	00-0074	$6.44	**$6.87**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0075	$6.44	**$6.87**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0077	$6.44	**$6.87**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0078	$6.44	**$6.87**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0079	$6.44	**$6.87**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0080	$6.44	**$6.87**
Closed	MH	Acorn	175	210	05-0964	$4.85	**$5.17**
Closed	MH	Floodlight	1000	1080	00-0043	$7.31	**$7.79**
Closed	MV	Cobra-Head	175	210	00-0002	$1.43	**$1.52**
Closed	MV	Post-Top Town & Country Type IV	175	210	00-0004	$0.75	**$0.80**
Closed	MV	Cobra-Head	250	290	05-0928	$0.75	**$0.80**
Closed	MV	Cobra-Head	400	432	05-0926	$0.75	**$0.80**

PSAL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Standard (Open)	LED	Cobra Head	20	22	05-3438	$11.13	**$11.87**
Standard (Open)	LED	Cobra Head	36	39	05-3285	$18.99	**$20.25**
Standard (Open)	LED	Cobra Head	56	62	05-3286	$19.05	**$20.31**
Standard (Open)	LED	Cobra Head	73	81	05-3287	$19.90	**$21.22**
Standard (Open)	LED	Cobra Head	107	118	05-3288	$19.90	**$21.22**
Standard (Open)	LED	Cobra Head	180	199	05-3289	$22.23	**$23.70**
Standard (Open)	LED	Floodlight	85	90	05-4090	$14.58	**$15.55**
Standard (Open)	LED	Floodlight	129	140	05-4091	$15.68	**$16.72**
Standard (Open)	LED	Floodlight	266	292	05-1091	$24.03	**$25.62**
Standard (Open)	LED	Town & Country	12	15	05-0905	$28.31	**$30.19**
Standard (Open)	LED	Town & Country	39	43	05-0906	$28.31	**$30.19**
Standard (Open)	LED	Town & Country	64	71	05-0907	$28.50	**$30.39**
Standard (Open)	LED	Traditionaire	23	27	05-3434	$30.13	**$32.13**
Standard (Open)	LED	Traditionaire	46	51	05-3435	$30.13	**$32.13**
Standard (Open)	LED	Traditionaire	77	85	05-3436	$30.13	**$32.13**
Standard (Open)	LED	Shoebox	100	110	05-3165	$25.51	**$27.20**
Standard (Open)	LED	Shoebox	130	145	05-3166	$26.91	**$28.70**
Standard (Open)	LED	Shoebox	160	180	05-3167	$28.01	**$29.87**
Open	LED	Franklin Park	86	90	05-9920	$45.05	**$48.03**
Open	LED	Franklin Park	80	93	05-9999	$45.05	**$48.03**
Open	LED	Signature	85	93	05-9960	$44.86	**$47.83**
Open	LED	Floodlight	85	93	05-0733	$54.10	**$57.68**
Open	LED	Deluxe Acorn Black	85	94	05-4071	$31.70	**$33.80**
Open	LED	HAGERSTOWN Black T-4	87	95	05-8317	$45.05	**$48.03**
Open	LED	Floodlight	0	140	05-9900	$21.01	**$22.40**
Open	LED	Floodlight	129	141	05-0734	$16.00	**$17.06**
Open	LED	Ecoform - Type III	158	173	05-6033	$26.75	**$28.52**
Open	LED	Floodlight	266	292	05-1095	$24.03	**$25.62**
Open	LED	Floodlight	363	400	05-0423	$23.42	**$24.97**
Closed	FLU	Fluorescent	400	510	00-0102	$21.75	**$23.20**
Closed	HPS	Dayform Traditionaire Black Type III	50	58	05-3410	$24.13	**$25.73**
Closed	HPS	Cobra-Head Cut-Off	50	58	05-0990	$9.59	**$10.23**
Closed	HPS	Post-Top Town & Country Black Type V	50	58	05-0947	$28.26	**$30.13**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$28.26	**$30.13**
Closed	HPS	Cobra-Head	50	58	05-0926	$19.51	**$20.80**
Closed	HPS	Traditional Bollard Type V	70	83	05-3400	$23.21	**$24.75**
Closed	HPS	Cobra-Head	70	83	05-0927	$19.51	**$20.80**
Closed	HPS	Granville Black Type III	100	117	05-6037	$27.98	**$29.83**
Closed	HPS	Profiler Type III	100	117	05-4593	$21.76	**$23.20**
Closed	HPS	Dayform Traditionaire Type III	100	117	05-3412	$25.82	**$27.53**
Closed	HPS	Cobra Head Cut-Off Type III	100	117	05-0991	$21.59	**$23.02**
Closed	HPS	Deluxe Acorn	100	117	05-0967	$23.15	**$24.68**
Closed	HPS	Post-Top Acorn	100	117	05-0963	$21.49	**$22.91**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$14.11	**$15.04**
Closed	HPS	Post-Top Town & Country	100	117	05-0948	$13.34	**$14.22**
Closed	HPS	Cobra-Head	100	117	05-0940	$19.51	**$20.80**
Closed	HPS	Capitol Type V	100	130	05-3200	$27.63	**$29.46**
Closed	HPS	Dayform Traditionaire Type III	150	171	05-3415	$28.67	**$30.57**
Closed	HPS	Dayform Traditionaire Type V	150	171	05-3317	$27.65	**$29.48**
Closed	HPS	Signature Type V	150	171	05-3212	$28.75	**$30.65**
Closed	HPS	Hagerstown Type V	150	171	05-3192	$33.94	**$36.19**
Closed	HPS	Old Boston Type V	150	171	05-0995	$22.67	**$24.17**
Closed	HPS	Shoe-Box-Small	150	171	05-0971	$28.81	**$30.72**
Closed	HPS	Post-Top Town & Country	150	171	05-0950	$16.56	**$17.65**
Closed	HPS	Cobra-Head	150	171	05-0941	$19.51	**$20.80**
Closed	HPS	Floodlight	150	171	05-0727	$16.18	**$17.26**
Closed	HPS	Floodlight	150	171	05-0722	$16.62	**$17.72**
Closed	HPS	Richmond Black Type III	150	177	05-4328	$27.81	**$29.66**
Closed	HPS	Swan - Type V	150	177	05-4103	$31.43	**$33.51**

PSAL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Franklin Park Type IV	150	177	05-4055	$28.15	**$30.02**
Closed	HPS	Edison III Type III	150	177	05-3326	$26.96	**$28.74**
Closed	HPS	Trenton Type V	150	177	05-3268	$24.49	**$26.11**
Closed	HPS	Deluxe Acorn	150	177	05-0968	$23.17	**$24.70**
Closed	HPS	Post-Top Acorn	150	177	05-0964	$22.65	**$24.15**
Closed	HPS	Trenton Type III	150	190	05-3263	$25.95	**$27.67**
Closed	HPS	Architectural Type III	150	190	05-3222	$25.95	**$27.67**
Closed	HPS	Offset Flood	250	300	05-1000	$37.85	**$40.36**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$17.63	**$18.80**
Closed	HPS	Shoe-Box-Small	250	300	05-0973	$21.40	**$22.82**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$28.81	**$30.72**
Closed	HPS	Cobra-Head	250	300	05-0928	$19.51	**$20.80**
Closed	HPS	Floodlight	250	300	05-0726	$19.60	**$20.90**
Closed	HPS	Floodlight	250	300	05-0723	$20.18	**$21.52**
Closed	HPS	Floodlight	400	449	05-0725	$27.12	**$28.91**
Closed	HPS	Floodlight Bronze	400	449	05-0724	$26.32	**$28.06**
Closed	HPS	Concourse Type III	400	450	05-3018	$32.78	**$34.95**
Closed	HPS	Expressway Flood	400	450	05-1001	$36.67	**$39.09**
Closed	HPS	Shoe-Box-Small	400	450	05-0979	$24.72	**$26.36**
Closed	HPS	Cobra-Head Cut-Off	400	450	05-0929	$20.75	**$22.12**
Closed	HPS	Cobra-Head	400	450	05-0925	$21.32	**$22.73**
Closed	HPS	Galleria Type AS	400	465	05-3111	$32.03	**$34.15**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$24.79	**$26.43**
Closed	HPS	Power Flood	750	839	05-0721	$34.02	**$36.27**
Closed	INC	600 Lumens NEMA Head	58	58	00-0081	$4.55	**$4.85**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0083	$4.78	**$5.09**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0084	$7.28	**$7.76**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0085	$8.17	**$8.71**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0086	$8.49	**$9.05**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0087	$8.35	**$8.90**
Closed	INC	15,000 Lumens NEMA Head	860	860	00-0088	$11.47	**$12.23**
Closed	IND	Cobra-Head Type III	40	40	05-0901	$12.09	**$12.89**
Closed	IND	Cobra-Head Type III	80	80	05-0902	$13.54	**$14.44**
Closed	IND	Cobra-Head Type III	150	150	05-0903	$18.10	**$19.30**
Closed	IND	Cobra-Head Type III	250	260	05-0904	$21.84	**$23.29**
Closed	MH	Granville Black Type III	100	130	05-6038	$31.40	**$33.48**
Closed	MH	Classic Bollard	100	130	05-3423	$41.24	**$43.97**
Closed	MH	Vandal Resistant Bollard Type V	100	130	05-3409	$29.84	**$31.81**
Closed	MH	Signature Black Type V	100	130	05-3215	$35.77	**$38.14**
Closed	MH	Franklin Park Type V	150	170	05-8312	$34.75	**$37.05**
Closed	MH	Hagarstown w/ Cutoff	150	190	05-8316	$37.14	**$39.60**
Closed	MH	Hagarstown w/ Cutoff Type V	175	210	05-4072	$38.66	**$41.22**
Closed	MH	Manor Lantern Type III	175	210	05-3615	$34.29	**$36.56**
Closed	MH	Signature Type IV & Type V	175	210	05-3217	$35.14	**$37.47**
Closed	MH	Hagerstown Type V	175	210	05-3197	$33.09	**$35.28**
Closed	MH	Post-Top Acorn	175	210	05-0965	$23.15	**$24.68**
Closed	MH	Bishops Crook	175	210	05-0911	$37.40	**$39.87**
Closed	MH	Tear Drop - Type III	250	280	05-8664	$39.96	**$42.60**
Closed	MH	Profiler Type III	320	350	05-8550	$28.58	**$30.47**
Closed	MH	Cobra-Head Type III	320	350	05-8018	$15.66	**$16.70**
Closed	MH	Floodlight	320	350	05-8003	$15.91	**$16.97**
Closed	MH	Cobra-Head Cut-Off	400	460	05-0930	$27.40	**$29.21**
Closed	MH	Gray Narrow Beam Floodlight	400	460	05-0729	$24.10	**$25.69**
Closed	MH	Floodlight	400	460	05-0728	$24.10	**$25.69**
Closed	MH	Profiler Type III	400	465	05-5025	$34.17	**$36.44**
Closed	MH	Shoe-Box-Large	400	465	05-0976	$25.68	**$27.38**
Closed	MH	Floodlight	1000	1080	05-0421	$33.02	**$35.21**
Closed	MV	Post-Top Town & Country Type IV	100	118	05-0936	$21.90	**$23.35**
Closed	MV	Post-Top Town & Country	100	118	05-0935	$21.90	**$23.35**
Closed	MV	Cobra-Head	100	118	05-0921	$19.38	**$20.66**
Closed	MV	Post-Top Town & Country Type IV	175	210	05-0938	$19.66	**$20.97**
Closed	MV	Post-Top Town & Country	175	210	05-0937	$19.66	**$20.97**
Closed	MV	Cobra-Head	175	210	05-0920	$19.38	**$20.66**
Closed	MV	Cobra-Head	250	290	05-0919	$19.38	**$20.66**
Closed	MV	Cobra-Head	400	432	05-0918	$19.38	**$20.66**
Closed	MV	Floodlight	400	453	05-0422	$18.26	**$19.47**
Closed	MV	Floodlight	1000	1075	05-0420	$29.72	**$31.69**
Closed	MV	Cobra-Head	1000	1085	05-0768	$17.88	**$19.07**

BPL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
ALUM	Classic I Black	10 ft.	04-1292	$28.76	**$30.67**
ALUM	Contemporary Black	10 ft.	04-4079	$38.52	**$41.07**
ALUM	Classic II Black	11 ft.	04-1301	$36.07	**$38.46**
ALUM	Windsor Black	11.5 ft.	04-1269	$29.57	**$31.53**
ALUM	Colonial Black	12 ft.	04-1264	$22.13	**$23.60**
ALUM	Rockford Harbor Fluted Black	12 ft.	04-6015	$32.40	**$34.55**
ALUM	Colonial Fluted Black	12 ft.	04-4036	$23.51	**$25.07**
ALUM	Heritage Black	12 ft.	04-3499	$31.45	**$33.53**
ALUM	Westwood Black	12 ft.	04-3260	$25.56	**$27.25**
ALUM	Classic I Green	12 ft.	04-1290	$30.82	**$32.86**
ALUM	Classic I Black	12 ft.	04-1280	$27.69	**$29.52**
ALUM	Colonial Fluted	12 ft.	04-1260	$22.09	**$23.55**
ALUM	Wadsworth Black	12 ft.	04-6011	$37.93	**$40.44**
ALUM	Contemporary Black	12 ft.	04-4435	$39.23	**$41.83**
ALUM	Montclair Green	12 ft.	04-4096	$37.54	**$40.03**
ALUM	Contemporary Black	12 ft.	04-4078	$39.23	**$41.83**
ALUM	Journal Square	12 ft.	04-4050	$39.23	**$41.83**
ALUM	Colonial Blue	12 ft.	04-4032	$34.32	**$36.59**
ALUM	Charleston Black	12 ft.	04-3302	$40.44	**$43.12**
ALUM	Montclair Black	12 ft.	04-1273	$38.96	**$41.54**
ALUM	Journal Square	12 ft.	04-4059	$42.51	**$45.33**
ALUM	Colonial Fluted Black	13 ft.	04-4440	$26.96	**$28.75**
ALUM	Colonial Round Black	14 ft.	04-1265	$22.87	**$24.39**
ALUM	Montclair Black	14 ft.	04-4085	$30.91	**$32.96**
ALUM	Heritage Black	14 ft.	04-3500	$31.67	**$33.77**
ALUM	Classic I Green	14 ft.	04-1291	$28.35	**$30.23**
ALUM	Classic II Black	14 ft.	04-1286	$28.93	**$30.85**
ALUM	Round Black	14 ft.	04-1284	$26.94	**$28.72**
ALUM	Classic I Black	14 ft.	04-1281	$30.70	**$32.73**
ALUM	Colgate I Black	14 ft.	04-1262	$28.21	**$30.08**
ALUM	Colonial Fluted Black	14 ft.	04-1261	$22.27	**$23.75**
ALUM	Square Bronze	14 ft.	04-1251	$19.50	**$20.79**
ALUM	Heritage Gray	14 ft.	04-3503	$41.27	**$44.00**
ALUM	Contemporary Black	14 ft.	04-4071	$39.58	**$42.20**
ALUM	Journal Square	14 ft.	04-4062	$40.77	**$43.47**
ALUM	Journal Square	14 ft.	04-4055	$39.58	**$42.20**
ALUM	Octagon Black	14 ft.	04-0199	$29.66	**$31.62**
ALUM	Classic I Black	14.5 ft.	04-1282	$27.20	**$29.00**
ALUM	Classic II	15 ft.	04-1287	$21.48	**$22.90**
ALUM	Contemporary Black	15 ft.	04-4072	$39.72	**$42.35**
ALUM	Colonial Fluted	16 ft.	04-4084	$31.46	**$33.54**
ALUM	Hudson Black	16 ft.	04-4083	$39.45	**$42.06**
ALUM	Contemporary Black	16 ft.	04-4073	$34.82	**$37.13**
ALUM	Square Bronze	16 ft.	04-4006	$24.99	**$26.65**
ALUM	Heritage Black	16 ft.	04-3501	$41.51	**$44.26**
ALUM	Classic I Black	16 ft.	04-1283	$28.98	**$30.90**
ALUM	Colonial Fluted	16 ft.	04-1272	$32.75	**$34.92**
ALUM	Classic II	16 ft.	04-1288	$36.49	**$38.91**
ALUM	Round	18 ft.	04-4017	$33.21	**$35.41**
ALUM	Classic II	18 ft.	04-1289	$36.63	**$39.06**
ALUM	Plainfield Black	19 ft.	04-4088	$46.59	**$49.68**
ALUM	Tall Decorative	20 ft.	04-4091	$43.68	**$46.57**
ALUM	Square 5 inch	20 ft.	04-1257	$23.78	**$25.36**
ALUM	Square Bronze	20 ft.	04-1252	$30.57	**$32.60**
ALUM	Decorative Black	25 ft.	04-3262	$46.47	**$49.55**
ALUM	Square Bronze	25 ft.	04-1258	$27.63	**$29.46**
ALUM	Round	25 ft.	04-1211	$35.36	**$37.70**
ALUM	Tall Decorative Black	25 ft.	04-4092	$38.95	**$41.53**
ALUM	Square	25 ft.	04-1276	$43.25	**$46.12**

BPL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)	
ALUM	Octagon Round	25 ft.	04-0198	$57.83	**$61.66**	
ALUM	Square Black	30 ft.	04-1254	$34.95	**$37.27**	
ALUM	Square Bronze	30 ft.	04-1250	$32.75	**$34.92**	
ALUM	Fluted	30 ft.	04-7098	$67.55	**$72.03**	
ALUM	Round	35 ft.	04-1230	$28.70	**$30.60**	
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$9.00	**$9.60**	
FIBERGLASS	Round Bronze	20 ft.	04-0203	$9.45	**$10.08**	
FIBERGLASS	Round Bronze	20 ft.	04-0203	$9.45	**$10.08**	
FIBERGLASS	Round Bronze	25 ft.	04-0204	$20.36	**$21.71**	
FIBERGLASS	Round Bronze	25 ft.	04-0204	$20.36	**$21.71**	
LAM WOOD	Laminated Wood Gray	30 ft.	04-0197	$15.83	**$16.88**	
LAM WOOD	Laminated Wood	30 ft.	04-0225	$14.44	**$15.40**	
PINE	Center Bored	30 ft.	04-0350	$9.20	**$9.81**	
PINE	Round	30 ft.	04-0302	$10.63	**$11.33**	
PINE	Round	35 ft.	04-0304	$12.56	**$13.39**	
PINE	Round Class IV	40 ft.	04-0306	$13.26	**$14.14**	
PINE	Round Class III	45 ft.	04-0308	$14.11	**$15.04**	
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$0.00	**$0.00**	*
FIBERGLASS	Round Bronze	20 ft.	04-0203	$2.64	**$2.81**	*
PINE	Round	30 ft.	04-0302	$0.00	**$0.00**	*
PINE	Round	35 ft.	04-0304	$0.00	**$0.00**	*
PINE	Round Class IV	40 ft.	04-0306	$4.35	**$4.64**	*
PINE	Round Class III	45 ft.	04-0308	$7.25	**$7.73**	*

* The charge for indicated poles installed prior to August 1, 2003

PSAL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
ALUM	Colonial Fluted	10 ft.	04-1247	$22.34	**$23.82**
ALUM	Classic I Black	10 ft.	04-1292	$35.51	**$37.86**
ALUM	Windsor Black	11.5 ft.	04-1269	$35.95	**$38.33**
ALUM	Classic I Black	12 ft.	04-1280	$36.23	**$38.63**
ALUM	Classic II	12 ft.	04-1285	$35.43	**$37.78**
ALUM	Colonial Fluted	12 ft.	04-1260	$28.96	**$30.88**
ALUM	Contemporary Black	12 ft.	04-0353	$35.39	**$37.73**
ALUM	Montclair Black	12 ft.	04-1273	$39.59	**$42.21**
ALUM	Wadsworth Black	12 ft.	04-6011	$30.30	**$32.31**
ALUM	Westwood Black	12 ft.	04-3260	$27.99	**$29.84**
ALUM	Heritage Black	12 ft.	04-3499	$39.86	**$42.50**
ALUM	Classic I Black	14 ft.	04-1281	$36.51	**$38.93**
ALUM	Classic II Black	14 ft.	04-1286	$37.30	**$39.77**
ALUM	Colgate I Black	14 ft.	04-1262	$40.50	**$43.18**
ALUM	Colonial Fluted Black	14 ft.	04-1261	$30.23	**$32.23**
ALUM	Colonial Round Black	14 ft.	04-1265	$30.66	**$32.69**
ALUM	Heritage Black	14 ft.	04-3500	$37.63	**$40.12**
ALUM	Square 5 inch	14 ft.	04-1256	$31.45	**$33.53**
ALUM	Square Bronze	14 ft.	04-1251	$25.63	**$27.33**
ALUM	Wadsworth Black	14 ft.	04-6009	$30.80	**$32.84**
ALUM	Classic I Black	14.5 ft.	04-1282	$37.58	**$40.07**
ALUM	Colonial Fluted	16 ft.	04-4084	$39.26	**$41.86**
ALUM	Contemporary Black	16 ft.	04-4073	$40.50	**$43.18**
ALUM	Heritage Black	16 ft.	04-3501	$41.51	**$44.26**
ALUM	Classic II	18 ft.	04-1289	$36.63	**$39.06**
ALUM	Square 5 inch	20 ft.	04-1257	$32.96	**$35.14**
ALUM	Square Bronze	20 ft.	04-1252	$27.84	**$29.68**
ALUM	Round	25 ft.	04-1211	$35.61	**$37.97**
ALUM	Square Bronze	25 ft.	04-1258	$38.03	**$40.55**
ALUM	Square Green 5 inch	25 ft.	04-5025	$37.09	**$39.55**
ALUM	Square Bronze	30 ft.	04-1250	$44.39	**$47.33**
ALUM	Round	35 ft.	04-1230	$38.93	**$41.51**
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$9.00	**$9.60**
FIBERGLASS	Round Bronze	20 ft.	04-0203	$11.20	**$11.94**
FIBERGLASS	Smooth Tapered Black	20 ft.	04-0205	$33.24	**$35.44**
FIBERGLASS	Round Bronze	25 ft.	04-0204	$13.24	**$14.12**
LAM WOOD	Natural	25 ft.	04-0195	$15.24	**$16.25**
LAM WOOD	Laminated Wood	30 ft.	04-0225	$21.44	**$22.86**
LAM WOOD	Laminated Wood Gray	30 ft.	04-0197	$24.79	**$26.43**
PINE	Center Bored	30 ft.	04-0350	$19.84	**$21.15**
PINE	Round	30 ft.	04-0302	$10.63	**$11.33**
PINE	Round Class 2	35 ft.	04-0112	$23.75	**$25.32**
PINE	Round	35 ft.	04-0304	$12.56	**$13.39**
PINE	Round Class IV	40 ft.	04-0306	$16.05	**$17.11**
PINE	Round Class III	45 ft.	04-0308	$19.26	**$20.54**

Item	Sheet No.		Description
Table of Contents	Original Sheet Nos. 2 to 3		Updated page numbers and inserted line for proposed new Distribution Adjustment Charge
Standard Terms & Conditions	Original Sheet No. 10		Updated the address for Board of Public Utilities.
			Updated methods for application of service
	Original Sheet No. 15		§ 3.7.1. (a) – Increased threshold for waiver of deposit requirement from $3,000 to $15,000
	Original Sheet No. 18		§ 3.8. – Corrected reference to §3.2. (f)
	Original Sheet No. 22		§ 7.1. Added opt-out provision for Advanced Metering Infrastructure (AMI)
	Original Sheet No. 24		§ 8.1. Added language explaining customer liability for changes in conditions without giving prior notice to the Company
	Original Sheet No. 25		§ 8.5. Added language specifying that preventative maintenance is customer's responsibility
	Original Sheet No. 28		§ 9.4.1. Deleted Remote Reading Device service fees
			Section now pertains to Remote Meter Reading (AMI) opt-out fees for meter change and monthly meter reading
			Removed additional obsolete language
	Original Sheet No. 29		Updated pricing for Data Pulses and removed obsolete language
			Updated language regarding customer access to meter data
	Original Sheet No. 32		§ 10.1. Added language addressing provision of Drivable Surfaces for Company vehicle access
	Original Sheet Nos. 32 to 34		Updated Discontinuance of Service language to reflect N.J.A.C. 14:3-3A
	Original Sheet No. 38		§ 14.5. – Struck obsolete language regarding manual data pull from interval meters
			§ 15.2. – Struck partial language referencing qualifications for Net Metering In addition, added limitations for participating in Community Solar
	Original Sheet No. 40		§ 15.8. – Program Availability for Net Metering
Regulation for Residential Underground Extension	Original Sheet No. 48		Corrected reference to § 3.7.2.
			Corrected item numbering under § B. Additional Charges
	Original Sheet No. 50		Updates to Unit Costs of Underground Construction – Single Phase
	Original Sheet Nos. 51 to 52		Updates to Unit Costs of Underground Construction – Three-Phase

Item	Sheet No.		Description
Clauses			
Distribution Adjustment Charge	Original Sheet No. 67		Added the Distribution Adjustment Charge
Third Party Supplier			
	Original Sheet No. 87		Removed mention of facsimile and hand delivery
Delivery			
Rate Schedule RS	Original Sheet No. 93 for Future		Introduction of a new time-of-use rate schedule offering customers the choice of a two-peak rate or a three-peak rate (RS-TOU)
	Original Sheet No. 94		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 95		Corrected language describing Minimum Charge
	Original Sheet No. 96 for Future		(a-8) Added terms for RS-TOU Program
	Original Sheet No. 97 for Future		Removed obsolete Special Provisions and replaced with (d) Special Provision for Residential Time of Use
	Original Sheet No. 98 for Future		Removed Special Provision (e-3)
Rate Schedule RHS	Original Sheet No. 100		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 101		Corrected language describing Minimum Charge
Rate Schedule RLM	Original Sheet No. 105 for Future		Proposed closing this rate schedule with implementation of RS-TOU
	Original Sheet No. 106		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language describing Minimum Charge
	Original Sheet No. 108 for Future		Added (a-8) and (a-9) Limitations on Service
Rate Schedule WH	Original Sheet No. 112		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule WHS	Original Sheet No. 118		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule HS	Original Sheet No. 124		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule GLP	Original Sheet No. 130		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet Nos. 134 to 135		Added provision for municipal or state public safety unmetered service
	Original Sheet No. 137		Proposed removing the special service charge for Night Use as everyone will be on AMI meters
	Original Sheet No. 141 for Future		Removed Special Provision for Distribution Demand Charge Rebate for DCFC customers
Rate Schedule LPL	Original Sheet No. 142		Carved out DCFC customers into a separate distribution-based rate structure
	Original Sheet No. 144		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 154		Removed Special Provision for Distribution Demand Charge Rebate for DCFC customers

Item	Sheet No.		Description
Rate Schedule HTS	Original Sheet No. 157		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule BPL	Original Sheet No. 184		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule BPL-POF	Original Sheet No. 197		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule PSAL	Original Sheet No. 207		Added the Distribution Adjustment Charge to applicable clauses

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 1**

TARIFF

FOR

ELECTRIC SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 4 through 7 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 2**

TABLE OF CONTENTS

Title Page ..... Sheet No. 1
Table of Contents ..... Sheet Nos. 2 and 3
Territory Served ..... Sheet Nos. 4 to 7, inclusive
Standard Terms and Conditions ..... Sheet Nos. 8 to 42, inclusive
Regulation for Residential Underground Extensions ..... Sheet Nos. 48 to 52, inclusive
Societal Benefits Charge ..... Sheet Nos. 57 to 58, inclusive
Non-utility Generation Charge ..... Sheet No. 60
Zero Emission Certificate Recovery Charge ..... Sheet No. 61
Solar Pilot Recovery Charge ..... Sheet No. 64
Green Programs Recovery Charge ..... Sheet No. 65
Conservation Incentive Program ..... Sheet Nos. 66- to 66D, inclusive
Distribution Adjustment Charge ..... Sheet No. 67
Tax Adjustment Credit ..... Sheet No. 69
Infrastructure Improvement Program Charges ..... Sheet Nos. 70 to 72, inclusive
Commercial and Industrial Energy Pricing (CIEP) Standby Fee ..... Sheet No. 73
Basic Generation Service
- Residential Small Commercial Pricing Electric Supply Charges
  - o BGS Energy & Capacity Charges ..... Sheet Nos. 75 and 76
  - o BGS Transmission and Energy Charges ..... Sheet No. 76
  - o BGS Capacity Charges and Transmission Charges ..... Sheet No. 79
  - o BGS Reconciliation Charges ..... Sheet No. 81
- Commercial And Industrial Energy Pricing Electric Supply Charges
  - o BGS Energy Charges, Capacity Charges and Transmission Charges ..... Sheet Nos. 82 and 83
  - o BGS Reconciliation Charges ..... Sheet No. 84

Third Party Supplier ..... Sheet No. 87

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 3**

TABLE OF CONTENTS
(Continued)

Rate Schedules and Payment Schedule as listed below:

	Rate Schedule	Sheet No.
Residential Service	RS	93-98
Residential Heating Service	RHS	99-102
Residential Load Management Service	RLM	105-108
Water Heating Service	WH	111-114
Water Heating Storage Service	WHS	117-120
Building Heating Service	HS	123-126
General Lighting And Power Service	GLP	129-141
Large Power And Lighting Service	LPL	142-154
High Tension Service	HTS	155-165

Other Services:

Payment Schedule – Purchased Electric Power	PEP	176-177
Body Politic Lighting Service	BPL	~~180~~179-191
Body Politic Lighting Service From Publicly Owned Facilities	BPL-POF	195-200
Private Street and Area Lighting Service	PSAL	203-214

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 4**

TERRITORY SERVED

BERGEN COUNTY

Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Maywood, Borough of
Midland Park, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of
Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Medford Lakes, Borough of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
Palmyra, Borough of
Pemberton, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westamptown, Township of
Willingboro, Township of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Gloucester, Township of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Hi-Nella , Borough of
Lawnside, Borough of
Magnolia, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Runnemede, Borough of
Somerdale, Borough
Tavistock, Borough of
Voorhees, Township of
Wood-Lynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
Washington, Township of
West Deptford, Township of
Westville, Borough of
Woodbury, City of
Woodbury Heights, Borough of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

HUDSON COUNTY (continued)

Union City, City of
Weehawken, Township of
West New York, Town of

MERCER COUNTY

Ewing, Township of
Hamilton, Township of
Hopewell, Borough of
Hopewell, Township of
Lawrence, Township of
Pennington, Borough of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Carteret, Borough of
Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Highland Park, Borough of
Metuchen, Borough of
Middlesex, Borough of
New Brunswick, City of
North Brunswick, Township of
Perth Amboy, City of
Piscataway, Township of
Plainsboro, Township of
South Brunswick, Township of
South Plainfield, Borough of
Woodbridge, Township of

MONMOUTH COUNTY

Allentown, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Lincoln Park, Borough of

PASSAIC COUNTY

Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Prospect Park, Borough of
Totowa, Borough of
Wayne, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 7**

TERRITORY SERVED
(Continued)

UNION COUNTY

Clark, Township of
Cranford, Township of
Elizabeth, City of
Fanwood, Borough of
Garwood, Borough of
Hillside, Township of
Kenilworth, Borough of
Linden, City of
Mountainside, Borough of
Plainfield, City of
Rahway, City of
Roselle, Borough of
Roselle Park, Borough of
Scotch Plains, Township of
Union, Township of
Westfield, Town of
Winfield, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX

		Sheet No.
1.	**General**	**10**
2.	**Obtaining Service**	**10**
	2.1. Application	10
	2.2. Initial Selection of Rate Schedule	10
	2.3. Deposit and Guarantee	11
	2.4. Permits	12
	2.5. Selection of Lighting Options	12
3.	**Charges For Service**	**12**
	3.1. General	12
	3.2. Definitions	12
	3.3. Removal of Public Service Facilities	13
	3.4. Temporary Service	13
	3.5. Provision of Service	14
	3.6. Extensions – General Provisions	15
	3.7. Charges for Extensions	15
	3.8. Charges for Increased Load	18
	Characteristics Of Service	**18**
4.	4.1. General	18
	4.2. Types of Service	19
	4.3. Losses	19
	Service Connections	**19**
5.	5.1. General	19
	5.2. Overhead Service	20
	5.3. Underground Service in Underground Zone	20
	5.4. Underground Service in Overhead Zone	20
	5.5. Change in Location of Existing Service Line	21
	Service Entrance Installations	**21**
6.	6.1. General	21
	6.2. Seals	21
	6.3. Secondary Distribution Service	21
	6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service	22
	Meters and Other Equipment	**22**
7.	7.1. General	22
	7.2. Other Devices	23
	7.3. Protection of Meters and Other Equipment	23
	7.4. Tampering	23
8.	**Customer's Installation**	**24**
	8.1. General	24
	8.2. Wiring	24
	8.3. Inspection and Acceptance	24
	8.4. Customer On-Site Generation	24
	8.5. Maintenance of Customer's Installation	25
	8.6. Electrical Equipment and Appliances	25
	8.7. Power Factor	25
	8.8. Liability for Customer's Installation	25
	8.9. Replacement of Customer Owned Equipment Due to System Upgrades	25
9.	**Meter Reading and Billing**	**25**
	9.1. Measurement of Electric Service	25
	9.2. Metering on Customer's Premises	26
	9.3. Testing of Meters	27
	9.4. Metering Options	27
	9.5. Billing Adjustments	30
	9.6. Meter Reading and Billing Period	30
	9.7. Proration of Monthly Charges	30
	9.8. Averaged Bills	30
	9.9. Budget Plan (Equal Payment Plan)	30
	9.10. Billing of Charges in Tariff	31
	9.11. Payment of Bills	31
	9.12. Late Payment Charge	31
	9.13. Returned Check Charge	32
	9.14. Field Collection Charge	32
10.	**Access To Customer's Premises**	**32**
11.	**Discontinuance Of Service**	**32**
	11.1. By Public Service	32
	11.2. At Customer's Request	34
12.	**Reconnection Charge**	**34**
13.	**Service Limitations**	**34**
	13.1. Continuity of Service	34
	13.2. Emergencies	34
	13.3. Unusual Conditions	35
14.	**Third Party Supplier**	**35**
	14.1. Third Party Supplier Electric Supply	35
	14.2. Initiation of Service	35
	14.3. Customer Billing Process	36
	14.4. Continuity of Service	37
	14.5. Interval Metering	37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

		Sheet No.
15.	**Net Metering Installations**	**38**
15.1.	General	38
15.2.	Size Limitations	38
15.3.	Installation Standards	38
15.4.	Initiation of Service	39
15.5.	Net Billing	39
15.6.	Billing Adjustments	40
15.7.	Budget Plan (Equal Payment Plan)	40
15.8.	Program Availability	40
16.	**New Jersey Authorized Taxes**	**40**
16.1.	New Jersey Sales and Use Tax	40
16.2.	New Jersey Corporation Business Tax	41
17.	**Termination, Change or Modification Of Provisions Of Tariff**	**42**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 10**

STANDARD TERMS & CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as a part of the Electric Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service," set forth the terms and conditions under which electric service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of electric service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution equipment located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit, or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, ~~Third Floor, Suite 314,~~ P.O. Box 350, Trenton, New Jersey, 08625-0350, 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. **Application:** An application for service may be made at any of the Customer Service Centers of Public Service in person, ~~by mail,~~ or by telephone, by the Company's website at www.pseg.com, ~~or by facsimile transmission~~ or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of electric service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters, in accordance with N.J.A.C. 14:3-3.2(e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of electricity to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13, Service Limitations and Section 14, Third Party Supplier Service Provisions of these Standards Terms and Conditions.

2.2. **Initial Selection of Rate Schedule:** Public Service will assist in the selection of the available rate schedule, which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customer may, upon written notice to Public Service within three months after service is begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS

(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle. Deposits shall cease to bear interest upon discontinuance of service.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it, after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities, and shall become effective on January 1 of the following year.

Interest payments shall be made at least once during each 12-month period in which a deposit is held and Public Service shall offer the customer the option of credits on bills toward utility service rendered or to be rendered or a separate check, in accordance with N.J.A.C. 14:3-3.5(h).

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service, Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 12**

STANDARD TERMS AND CONDITIONS

(Continued)

2.4. Permits: Public Service, where necessary, will make application for any street opening permits for installing its service connections and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. Selection of Lighting Options: Public Service will assist in the selection of lighting options by making recommendations for the most appropriate option based on the customer's defined illumination needs. However, responsibility for the final selection shall, at all times, rest with the customer. Any advice given by Public Service will be based on the customer's statements and by giving such advice, Public Service assumes no responsibility, nor shall it incur liability.

3. CHARGES FOR SERVICE

3.1. General: Charges for electrical usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for electrical usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard or Atypical Conditions, or for an Extension.

3.2. Definitions: The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded electric service from Public Service.
b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.
c) N.J.A.C. is the New Jersey Administrative Code.
d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus the sum of Basic Generation Service charges including SUT, and, unless included with Basic Generation Service charges, Transmission Charges, including SUT, derived from FERC approved transmission charges; all assessed in accordance with this Tariff for Electric Service.
e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for electric transmission (non-FERC jurisdictional) and/or distribution, whether located overhead or underground, on a public street or right of way, or on private property or private right of way, and includes the conductors, poles or supports, cable, conduit, rights of way, land, site restoration, handholes, manholes, vaults, line transformers, protection devices, metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the point of connection with the customer's facilities, but also includes the meter. Details of the requirements for Service Connections and Service Entrance Installations are provided in Sections 5 and 6 of these Standard Terms and Conditions and in the New Jersey Uniform Construction Code. The new plant and/or facilities installed constituting an Extension must be nominally physically and electrically continuous from the beginning to the end of the Extension, but also includes the meter.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where either: 1) Public Service facilities of the required voltage or number of phases did not previously exist, or 2) existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. **Removal of Public Service Facilities:** There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

3.4. **Temporary Service:** Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS

(Continued)

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will be furnished only under Rate Schedules GLP, LPL, and HTS except that it will not be supplied for cogeneration or standby purposes under any rate schedule at locations where electric service is regularly supplied from another source, nor will it be supplied under Rate Schedules BPL, BPL-POF and PSAL.

3.5. Provision of Service: Electric service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon Applicant's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. Standard Conditions: Overhead construction will be utilized for all distribution lines except in certain areas designated by Public Service as underground zones where underground construction will be utilized. An area is designated as an underground zone by Public Service based upon load density, area size, building occupation and the need for multiple and/or express circuits.

3.5.2. Atypical Conditions: When underground distribution lines or service connections in overhead zones are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such underground construction over the estimated costs of equivalent overhead construction, such total grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges, Facilities Charges, distribution capacity reservation charges or other charges as may be equitable under the circumstances involved where: (1) large or special investment is either necessary for the supply of service or is requested by the Applicant; (2) oversized transformers, feeders, or other special facilities are installed to serve an Applicant using equipment in such manner that the use of electric service is intermittent, momentary or subject to violent fluctuations; (3) capacity required to serve Applicant's equipment is out of proportion to the use of electric service for occasional or low load factor purposes, or is for short durations; or (4) service characteristics requested by Applicant differ from those normally supplied for a given size and type of load as specified in the current "Information and Requirements for Electric Service".

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

Facility Charges will be assessed on a monthly basis equal to 1.45% (1.55% including SUT) times the total installed cost of the excess facilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 15**

STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the Applicant to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. Where a large portion of the cost of construction is related to the installation of underground facilities, the costs may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $~~3,000.00~~15,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 16**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.2. Multi-unit Developments: Where application for service is made for electric service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) The Regulations on Residential Underground Extensions, New Jersey Administrative Code 14:5-4.1 *et seq.* shall apply regarding the installation of Public Service facilities within the boundaries of such applicable developments. Such charges, referred to hereafter as B.U.D. Charges, are included elsewhere in this Tariff and shall be treated as a non-refundable contribution.

b) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions and, if applicable, B.U.D. Charges, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where the ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

c) As each unit is connected, as determined by the setting and activation of the Public Service electric meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

d) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

f) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 17**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, less ten times the estimated average annual distribution revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service electric meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 18**

STANDARD TERMS AND CONDITIONS
(Continued)

3.8. Charges for Increased Load: When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2. (~~hf~~) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

4. CHARACTERISTICS OF SERVICE

4.1. General: The standard service supply of Public Service is alternating current with a nominal frequency of 60 hertz (cycles per second). All types of service listed below are not available at all locations, and service from the primary distribution, subtransmission, transmission or high voltage system may be specified under special conditions, such as location, size, or type of load. The customer shall ascertain and comply with the service characteristics requirements of Public Service which are covered in detail in “Information and Requirements for Electric Service,” issued by Public Service and available on request.

Public Service must always be consulted to determine the type of service to be supplied to a particular installation. The type of service may govern the characteristics of equipment to be connected.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 19**

STANDARD TERMS AND CONDITIONS
(Continued)

4.2. Types of Service: Subject to the restrictions in Section 4.1, the types of service available, with their nominal voltages are:

Type of Service		Volts
Secondary Distribution Service	Single-phase, two-wire	120
	Single-phase, three wire	120/240
	Single-phase, three-wire	120/208
	Three-phase, three-wire	240
	Three-phase, four wire	120/240
	Three-phase, four wire	120/208
	Three-phase, four-wire	277/480
Primary Distribution Service	Three-phase, four wire	2,400/4,160
	Three-phase, four-wire	13,200
Subtransmission Service:	Three-phase, three-wire	26,400
	Three-phase, three-wire	69,000
High Voltage Service:	Three-phase, three-wire	138,000
	Three-phase, three-wire	230,000
Transmission Service	Three-phase, three-wire	69,000

4.3. Losses: Nominal electric losses and unaccounted for percentages:

Type of Service	Losses
Secondary Distribution Service:	5.8327%
Primary Distribution Service:	3.3153%
Subtransmission Service:	2.0472%
Transmission High Voltage Service:	0.8605%

5. SERVICE CONNECTIONS

5.1. General: The customer shall consult Public Service before starting work, to determine the type of service facilities involved, the exact location of the point of connection between customer's service entrance and Public Service's facilities and the construction to be installed by each.

Electric service will be supplied to each building or premises through a single service connection unless otherwise agreed in accordance with the detailed requirements of "Information and Requirements for Electric Service," Section 3.

Whenever conductors are required under or within a building to provide a continuous service run to the customer's entrance equipment, they shall be installed by Public Service at the expense of the customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 20**

STANDARD TERMS AND CONDITIONS

(Continued)

Where a customer is provided Subtransmission, Transmission or High Voltage Service, the customer's high side bus shall be considered part of the Public Service distribution system for operational purposes with no remuneration to the customer by Public Service.

5.2. Overhead Service: For overhead service in overhead zones, Public Service will furnish, install, and maintain the overhead service facilities to the point of connection to the customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.3. Underground Service in Underground Zone: For underground service in underground zones, Public Service will furnish, install, and maintain the underground service facilities to the point of connection to customer's facilities. A deposit or non-refundable contribution may be required as provided in Section 3 of these Standard Terms and Conditions.

5.4. Underground Service in Overhead Zone:

5.4.1. Secondary Distribution Service: Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is inadequate for the size of customer's load, the customer shall furnish and install at its expense and in accordance with the specifications of Public Service the primary conduits and any necessary manholes, which will be maintained by Public Service. The customer shall also be required to furnish, install, and maintain all secondary conduits and conductors and provide space on its property for necessary transformation.

Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is adequate for the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install the service facilities at its expense and in accordance with the specifications of Public Service. Public Service will connect the service conductors and maintain the service facilities without charge to the customer.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.4.2. Primary Distribution Service: Where underground service in an overhead zone is to be supplied, and primary voltage supply is required because of the size of the customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 21**

STANDARD TERMS AND CONDITIONS

(Continued)

5.4.3. Subtransmission Service: Where underground service in an overhead zone is to be supplied, and subtransmission voltage supply is required because of the size of customer's load, such service will be supplied under the following condition:

At Request of Customer or for Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at its expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities.

5.5. Change in Location of Existing Service Line: Any change requested by the customer in the location of the existing service line, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. SERVICE ENTRANCE INSTALLATIONS

6.1. General: The customer is required to furnish, install, and maintain the service entrance wiring and equipment on the customer's premises with the exception of transformers and network protectors for secondary service, and meters and metering equipment as enumerated in detail in the following paragraphs. All materials and equipment used shall be of a type approved by Public Service and must be installed according to the requirements of governmental authorities, Public Service, and the current edition of the National Electrical Code. The location of the service entrance installation must be designated by Public Service.

6.2. Seals: Public Service will seal or lock all meters and enclosures containing meters and associated metering equipment, service entrance interrupting devices acceptable to Public Service, or unmetered wiring. No person except a duly authorized employee of Public Service is permitted to break or remove a Public Service seal or lock.

6.3. Secondary Distribution Service: For new installations to be metered at voltages not exceeding 600 volts, meter-mounting equipment and, where required, current transformers, potential transformers, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

For large secondary installations, the customer may be required to furnish a vault or space for a transformer mat, pad, manhole, or vault.

The customer shall ascertain and comply with the general requirements of Public Service for secondary installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 22**

STANDARD TERMS AND CONDITIONS
(Continued)

6.4. Primary Distribution, Subtransmission, Transmission or High Voltage Service: For new installations to be metered at voltages exceeding 600 volts, meter-mounting equipment, current transformers, potential transformers, test switches, time switches, and associated unmetered wiring will be furnished without charge to the contractor, or may be furnished by the contractor at its expense if approved by Public Service. The contractor will install and wire this equipment as part of its contract with the customer. Public Service will furnish and install the meter.

Where service is received at primary distribution, subtransmission, transmission or high voltage entrance voltages, customer must furnish, install and maintain a service entrance interrupting device acceptable to Public Service and, where necessary, transformers and appurtenances.

The customer shall ascertain and comply with the general requirements of Public Service for primary distribution, subtransmission, transmission or high voltage service installations, which are covered in detail in "Information and Requirements for Electric Service," issued by Public Service and available on request.

Where subtransmission, transmission or high voltage service is supplied, it is necessary that the switching operations be controlled by Public Service; therefore, customer shall agree to abide by the operating instructions issued to customer by Public Service.

7. METERS AND OTHER EQUIPMENT

7.1. General: The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

Public Service will select the type and make of metering and its other equipment, and may, from time to time, change or alter such equipment; its sole obligation is to supply metering that will furnish accurate and adequate records for billing purposes.

Electric service normally will be supplied to each building or premises at a single metering point, by one watthour meter equipped, where necessary, with demand and recording devices. Additional meters will be installed (1) where, in the judgment of Public Service, the operating characteristics of its system require the installation of more than one meter, or (2) at the customer's request provided that the service measured by each meter shall be billed separately at an applicable rate schedule.

No person except a duly authorized employee or agent of Public Service is permitted to alter or change a meter or its connection.

When requested by a customer, equipment to provide ~~remote meter reading,~~ data pulses and/or advanced interval meter access may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

A customer may choose to opt-out of remote meter reading and request a conventional meter and will be charged additional fees as detailed in Section 9.4.1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 23**

STANDARD TERMS AND CONDITIONS

(Continued)

7.2. Other Devices: No branch circuits or devices are permitted on the supply side of the meter, except those for Police Recall or Fire Alarm System Service as provided in this Tariff.

Public Service will not permit the connection of the customer's ammeters, voltmeters, pilot lamps, or any other energy-using devices to the instrument transformers used in conjunction with its meter.

7.3. Protection of Meters and Other Equipment: Customer shall provide for the safekeeping of the meter and other equipment of Public Service, and shall not tamper with or remove such meter or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or its agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

7.4. Tampering: In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such electric service under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, based upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service under the applicable rate schedule, exclusive of any reduction in charges for third party supplied electric services, alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Generation Service default service, exclusive of any reduction in charges for third party supplied electric services, but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 24**

STANDARD TERMS AND CONDITIONS
(Continued)

8. CUSTOMER'S INSTALLATION

8.1. **General:** Public Service makes no new electric installations on the customer's premises other than the installation of its services, meters and other equipment as set forth in these Standard Terms and Conditions except to continue a service run, a portion of which is installed under or within a building at the customer's expense. Public Service will assume no responsibility for the condition of customer's electric installation or for accidents, fires, or failures which may occur as the result of the condition of such electric installation. No material change in the size, total electrical capacity, or method of operation of customer's equipment shall be made without previous written notice to Public Service.

Failure of the Customer to give prior notice of changes in conditions as described above shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees.

8.2. **Wiring:** Wiring installed on the customer's premises must conform to all requirements of governmental authorities and to the regulations set forth in the current edition of the National Electrical Code.

8.3. **Inspection and Acceptance:** The customer's service entrance installation must be inspected and approved by Public Service before service will be supplied. Public Service may refuse to connect with any customer's installation or make additions or alterations to the service connection when it is not in accordance with the National Electrical Code and with these Standard Terms and Conditions, and where a certificate approving the customer's electrical installation has not been issued by a county or a municipality or by any other organization authorized to perform such functions and services as may be designated and approved by the Board of Public Utilities. Information regarding the above inspection service is detailed in "Information and Requirements for Electric Service," issued by Public Service and available on request.

8.4. **Customer On-Site Generation:**

8.4.1. **General:** Electric service from a customer's on-site generation facility, or from sources other than that delivered by Public Service's system shall not be used for the operation of customer's electrical equipment without previous written notice to Public Service. The requirements in this Section 8.4.1 do not apply when the on-site generation facility is used exclusively as an emergency source of power during Public Service electric delivery service interruptions.

8.4.2. **Parallel Operation:** Customer may operate on-site generation facility in parallel with the service delivered by Public Service only with previous written notice to Public Service and written Public Service approval**,** and must conform with all applicable interconnection standards.

Public Service may re-energize the Public Service delivery service following an interruption without prior notice to the customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 25**

STANDARD TERMS AND CONDITIONS

(Continued)

8.5. **Maintenance of Customer's Installation:** Customer's entire electrical installation shall be maintained in the condition required by the electrical inspection agency having jurisdiction and by Public Service, and all repairs shall be made by the customer at their expense. Preventative and corrective maintenance on customer owned equipment is the responsibility of the customer. Further, customer electrical equipment under the operational control of Public Service shall be subject to Public Service's inspection and where necessary Public Service will advise the customer to make necessary repairs at customer expense. In the event PSE&G provides assistance in repairs or maintenance activities, customers will be responsible for those costs. If the customer fails to make the necessary repairs in a timely manner, then Public Service will have the repairs made and bill the customer.

8.6. **Electrical Equipment and Appliances:** Motors, welders, and other electrical equipment and appliances shall be so wired, connected, and operated as to produce no disturbing effects on the Public Service electrical system which will affect the adequacy or quality of service to other customers.

Where the use of electric service is to be intermittent, occasional or momentary, or subject to violent fluctuations, or for low load factor purposes or for short durations equipment shall not be connected without previous written notice to Public Service.

8.7. **Power Factor:** The average power factor under operating conditions of customer's load at the point where the electric service is metered shall not be less than 85%. Public Service may inspect customer's installed equipment and may place instruments for test purposes at its own expense on the premises of the customer.

Where neon, fluorescent, or other types of lighting or sign equipment having similar low power factor characteristics are installed or moved to a new location, the customer shall furnish, install, and maintain at its own expense corrective apparatus which will increase the power factor of the individual units or the entire lighting installation to not less than 90%.

8.8. **Liability for Customer's Installation:** Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customer's facilities or the equipment of others on customer's premises. Public Service will not be liable for the use, care or handling of the electric service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customer's facilities.

8.9. **Replacement of Customer Owned Equipment Due to System Upgrades:** If customer owned communication equipment, such as relays, requires replacement in order to be compatible with PSE&G's system due to upgrade work being performed by PSE&G, the Company will provide the replacement at no cost to the Customer. Any equipment replaced by PSE&G under this section shall be owned by PSE&G. In all other circumstances including customer requirements or obsolescence, the equipment will be replaced at their expense and in accordance with other sections of this tariff.

9. METER READING AND BILLING

9.1. **Measurement of Electric Service:** Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 26**

STANDARD TERMS AND CONDITIONS

(Continued)

Where more than one meter is furnished and installed for Public Service operating reasons, as set forth in Section 7.1 of these Standard Terms and Conditions, the kilowatt-hour use measured by the meters will be combined for billing purposes at an applicable rate schedule selected by the customer.

When demand is measured, the customer's monthly maximum demand shall be the sum of the maximum kilowatt demands, determined in accordance with the provisions of the selected rate schedule, as recorded by the individual meters.

Where more than one meter is furnished and installed at the request of the customer, kilowatt-hour use and kilowatt demand measured by each meter will be billed separately at an applicable rate schedule selected by the customer.

Bills will be based upon registration of Public Service meters, except as otherwise provided for in this tariff.

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premises is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors. The Generation Obligation for customers taking service in a new facility, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premises. More specifically the customer's Generation Obligation is established based upon the following: 1) an estimate of the customer's peak demand, based upon the load shape of a representative sample of customers served under the same rate schedule, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer's actual or estimated, as applicable, summer peak demand, depending upon the type of metering equipment installed by Public Service, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once a year.

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above.

9.2. Metering on Customer's Premises:

9.2.1. General: The service and supply of electrical energy by Public Service for the use of owners, landlords, tenants or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters.

The service and supply of electrical energy by Public Service to owners, landlords, tenants or occupants of industrial or commercial buildings or residential premises as noted below in Section 9.2.2 and not limited by the above paragraph may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying electric service from Public Service be permitted to resell it for a profit.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 27**

STANDARD TERMS AND CONDITIONS
(Continued)

9.2.2. Sub-Metering: The practice where a customer of Public Service or a customer of record, through the use of direct metering devices, installed, maintained and operated at such customer's expense, monitors, evaluates or measures their own consumption of electrical energy or the consumption of a tenant for accounting or conservations purposes.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all electric consuming devices must be metered through a single sub-meter.

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

9.3. Testing of Meters: At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

9.4. Metering Options: The following optional metering services are available to customers and are subject to the charges as indicated in the following subsections:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 28**

STANDARD TERMS AND CONDITIONS
(Continued)

~~**9.4.1. Remote Reading Devices:** Public Service will install and maintain the necessary equipment to provide remote meter reading at the customer's request, at the applicable charges listed below. Customers requesting this service are subject to a minimum term of one year. This service is not available to customers with an interval meter installed.~~

~~Type of Service~~	~~Set-Up Charges~~	~~Set-Up Charges Including SUT~~	~~Monthly Charge~~
~~Single Phase~~	~~$ 110.00~~	~~$ 117.29~~	~~$ 1.00~~
~~Three Phase~~	~~190.00~~	~~202.59~~	~~2.00~~

9.4.~~2~~1. ~~Interval Metering~~Remote Meter Reading (AMI): In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, Public Service currently provides remote capable AMI meters as the standard equipment. For residential customers only, a non-communicating meter can be installed at the customer's expense.

In the event the customer chooses not to have an interval meter/advanced meter installed on their premises, the following fees shall apply.~~interval meters to support billing and/or measurement of certain rate schedules and/or Special Provisions. For all other customers interval meters can be supplied, at the customer's option, at the applicable charges listed below. Customers requesting this service are subject to a minimum term of one year.~~

Type of Service	Set-Up Charge~~s~~	~~Set-Up~~ Charge~~s~~ Including SUT	Monthly Charge	Monthly Charge Including SUT
Meter Change (residential only)~~Single Phase~~	$45.00 ~~$ 450.00~~	$47.98 ~~$ 479.81~~	~~$ 31.00~~	
Monthly meter reading fee~~Three Phase~~	~~530.00~~	~~565.11~~	$12.00 ~~32.00~~	$12.79

~~If a customer elects to install its own telecommunications to support the interval meter(s), the installation is to be performed in accordance with Public Service's Standards for Telecommunications for Interval Meters, a copy of which is available upon request. If the customer elects to install its own telecommunications, the customer will be responsible for all monthly telephone charges. If the customer requests that Public Service provide the dedicated telephone line, Public Service may utilize an independent third party to install the telephone line and will bill the customer for the actual cost of the installation, which is in addition to the Set-Up Charges indicated above, as well as the actual monthly communications charges. The Set-Up Charge and telephone installation charge, if applicable, will be billed upon completion of the installation of the interval metering device and telecommunications (if applicable). The Monthly Charge, applied in accordance with Section 9, Meter Reading and Billing, shall commence on the date the meter is installed and will be included in the customer's regularly scheduled monthly Public Service bill.~~

~~If the telecommunications provided by a customer to an interval meter is not operable at the time of a monthly meter reading date, Public Service will notify the customer and manually obtain the data from the interval meter. If such a condition occurs for two consecutive meter reading dates, Public Service may charge the customer for the cost to manually obtain the interval data for the subsequent months' meter readings (after the second consecutive month) until the problem is remedied. The charge to provide this manual data collection is $50.00 ($53.31 including SUT) per month. If the customer does~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 29**

STANDARD TERMS AND CONDITIONS
(Continued)

~~not remedy the telecommunications problem after four (4) consecutive meter reading dates, and the customer purchases its energy from a Third Party Supplier, Public Service, at its discretion, reserves the right to use load profile information for retail settlement until the telecommunication problem is remedied.~~

~~Customers that had an interval electric meter installed at their premises at Public Service expense and the meter is no longer required by Public Service for operating and billing purposes may choose to retain the installed meter. Customers that choose to retain the installed interval meter will be billed the Monthly Charge plus the telecommunications charge.~~

9.4.~~3~~2. Customer Access to Meter Data:

a) **Data Pulses:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use at the customer's request, in accordance with the applicable charges listed below. Customers requesting these services are subject to a minimum term of one year.

Type of Service	Set-Up Charges	Set-Up Charges Including SUT	Monthly Charge
Single Phase	$ ~~80.00~~ 364.52	$ ~~85.30~~ 388.67	$ 1.00
Three Phase	~~280.00~~ 364.52	~~298.55~~ 388.67	2.00
Three Phase – time and data pulses	410.00	437.16	3.00

~~b) **Real Time Interval Meter Access:** Where Public Service has installed an interval meter, Public Service will maintain the necessary equipment to provide remote real time access to interval electric meter data at the customer's request. Customers requesting these services are subject to a minimum term of one year. The charges for this service shall include a set-up charge of $620.00 per meter ($661.08 including SUT), and a monthly charge of $32.00 per meter per month.~~

~~c) **Access to Historical Interval Usage Data**: Where Public Service has an interval meter installed, twelve months of historical interval usage, where available, will be provided upon request of the customer. The historical interval usage data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.~~

b) **Access to Historical Interval Usage Data:** Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical interval usage data on a next-day basis through the customer account portal, including Green Button download.~~for those customers who request such service. The charges for this service shall include a set-up charge of $80.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 30**

STANDARD TERMS AND CONDITIONS
(Continued)

9.5. Billing Adjustments: Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RS, RHS or RLM, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments will be made in accordance with N.J.A.C. 14:3-4.6.

9.6. Meter Reading and Billing Period: All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

9.7. Proration of Monthly Charges: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts, the minimum period for billing purposes shall be one month.

9.8. Averaged Bills: Where Public Service is unable to read the meter, Public Service may estimate the amount of electric service supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue electric service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours, or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

9.9. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RS or RHS or GLP (where GLP electric service is used for residential purposes in buildings of four or fewer units) shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve-month period will be averaged over twelve months and may be paid in twelve equal monthly installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 31**

STANDARD TERMS AND CONDITIONS

(Continued)

9.10. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of electric service subsequent to the scheduled meter reading date for the immediately preceding month.

9.11. Payment of Bills: At least 15 days time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow a customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

9.12. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedules RS, RHS, RLM, WH, WHS, BPL and BPL-POF. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills, and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 32**

STANDARD TERMS AND CONDITIONS

(Continued)

9.13. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

9.14. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules GLP, LPL, PSAL, HS and HTS.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized government officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon ~~reasonable~~ notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) non-payment of a valid bill due for service furnished at a present or previous location, however, nonpayment~~. However, non-payment~~ for business service shall not be a reason for discontinuance of ~~residence~~ residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 9.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

Public Service~~The Company~~ shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for non-payment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $~~100~~200.00; and 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for non-payment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 33**

STANDARD TERMS AND CONDITIONS
(Continued)

landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 9.11 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of non-payment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for non-payment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. to and 4:00 P.M., Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or a holiday, absent such emergency.

Subject to the conditions set forth below, dDiscontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. and the customer gives reasonable proof of inability to pay. Discontinuance shall be prohibited for a period of up to 90 days initially2 months when a customer submits a licensed medical professional'sphysician's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. Recertification by the physician as to continuance of the medical emergency shall be submitted to Public Service after 30 days. However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provisions of N.J.A.C. 14:3-7.76.

1. The Board may extend the 6090-day period for good cause upon the receipt of a written request from the customer. That The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for non-payment prior to submission of the licensed medical professional'sphysician's statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be shut offdiscontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be hand hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 34**

STANDARD TERMS AND CONDITIONS
(Continued)

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits ~~of: (1)~~under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of ~~); (3)~~ Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) ~~Persons~~ persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be ~~95~~ 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for nonpayment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 35**

STANDARD TERMS AND CONDITIONS

(Continued)

13.2. Emergencies: Public Service may curtail or interrupt service or reduce voltage to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

In the event of an actual or threatened restriction of electric supplies available to its system or the systems to which it is directly or indirectly connected, Public Service may, after due notice to the Board, curtail or interrupt service or reduce voltage to any customer or customers if such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of electric service it will supply and may refuse service to new customers or to existing customers for additional load if the necessary electric supply is unavailable or if Public Service is or will be unable to deliver, the necessary energy, or to obtain the necessary equipment and facilities to supply such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Electric Supply: Customers served on any of the applicable rate schedules of this Tariff for Electric Service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier (TPS) must provide appropriate authorization as required by the TPS. Customers who are not enrolled with a TPS will continue to receive Basic Generation Service electric supply.

A TPS is a retail energy and capacity provider that has been licensed by the Board and has executed a Third Party Supplier Agreement with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. The customer may act as a third party supplier for its account if the customer meets all of the requirements of this Tariff.

14.1.1. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain a TPS for electric supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center.

14.2. Initiation of Service: In order to be eligible to receive electric supply from a TPS, the customer must contract with a TPS to obtain electric supply for delivery to the customer by Public Service. Delivery of electric supply to retail customers will be provided in accordance with the terms of the Third Party Supplier Agreement. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of electric supply. Initiation of service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection.

Once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, which process is as set forth in this subsection and in Section 14.1, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer. This letter of confirmation shall be provided within one day and shall include notification of the customer's right to rescind their contract with their designated TPS in accordance with Board established procedures. This right to rescind must be exercised within seven (7) days of mailing of the letter of confirmation. In the event of a dispute, assignment of a customer will not

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 36**

STANDARD TERMS AND CONDITIONS

(Continued)

occur unless and until the dispute is resolved. Once assignment has occurred, the TPS will be required to provide all of the electric supply consumed on the Public Service customer's account (single point of delivery).

14.2.1. Customer Change of Third Party Supplier: If a customer subsequently elects to change its TPS, the customer must provide appropriate authorization as required by their TPS and as set forth in Section 14.1 and Section 14.2. Service from this alternate TPS will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt by Public Service from the TPS of the customer's selection. Upon enrollment with a TPS, the customer may not change its TPS more frequently then once every billing month cycle.

14.2.2. Customer Return to Public Service Rate Schedule Electric Supply:

a) If the customer subsequently returns to Public Service as supplier of electric supply, the return to Public Service will become effective on the customer's next scheduled meter reading date that is at least thirteen (13) days following the receipt of customer notification by Public Service. Public Service shall confirm the customer's selection of Public Service as its provider of electric supply by sending a letter of confirmation to the customer and the customer shall have the right to rescind in accordance with Section 14.2, Initiation of Service, of these Standard Terms and Conditions.

b) If a customer's TPS no longer satisfies the requirements imposed on it by the Third Party Supplier Agreement, such customer shall immediately return to, and receive electric supply from Public Service under customer's applicable rate schedule unless and until customer selects another TPS in accordance with Section 14.2.1. The customer shall be advised by Public Service in writing of this change in supplier.

14.2.3. Third Party Supplier's Termination of Customer's Electric Supply: A TPS will not be permitted to physically connect or disconnect energy service to a customer.

14.3. Customer Billing Process: Public Service will provide one combined bill to the TPS's retail customer(s) containing both Public Service charges and TPS electric supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for TPS services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for TPS services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.3.1. Payment of Bills: Payment of bills, including TPS's charges for electric supply if billed by Public Service, shall be made to Public Service and shall be in accordance with Section 9, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 37**

STANDARD TERMS AND CONDITIONS

(Continued)

14.3.2. Late Payment Charges: A late payment charge in accordance with Section 9.12, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for electric supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for electric supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges, and all undisputed TPS charges for electric supply if such charges are billed by Public Service, in accordance with Section 9, Meter Reading and Billing, and Section 14.3.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customers and their TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.4. Continuity of Service: In addition to the terms specified in Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions, Public Service shall have the right (i) to require a TPS's electric supply sources to be disconnected from Public Service's electrical system; (ii) to otherwise curtail, interrupt, or reduce a TPS's electric supply; or (iii) to disconnect a TPS's customer(s) whenever Public Service determines, or whenever Public Service is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of Public Service's or PJM members' facilities; to maintain the safety and reliability of Public Service's electrical system and any generation facilities attached thereto; or due to Emergencies, minimum generation ("light load") conditions, forced outages, potential overload of Public Service's or PJM's transmission and/or distribution circuits or events of Force Majeure including, but not limited to, those events specified in Section 13.1, Continuity of Service, of these Standard Terms and Conditions.

14.5. Interval Metering: In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, customers being served by a TPS that have interval meters will be billed using the data obtained from those meters. If the interval meter is not operational, customer's hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 38**

STANDARD TERMS AND CONDITIONS
(Continued)

~~If the telecommunications provided by a customer to an interval meter is not operable at the time of a monthly meter reading date, Public Service will notify the customer and manually obtain the data from the interval meter. If the telecommunications to an interval meter is not operable for two consecutive meter reading dates, Public Service may charge the customer for the cost to manually obtain the interval data for the subsequent months' meter readings (after the second consecutive month) until the problem is remedied. The charge to provide this manual data collection is $50.00 ($53.31 including SUT) per month. If the customer does not remedy the telecommunications problem after four (4) consecutive meter reading dates, Public Service reserves the right to bill third party supplied customers on the basis of a load profile for the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service, until the telecommunication problem is remedied.~~

15. NET METERING INSTALLATIONS

15.1. **General:** For the purpose of this Section of the Tariff for Electric Service a customer-generator is a customer that generates electricity using Class I renewable resources as defined in N.J.A.C. 14:8-1.2 on the customer's side of the meter. Net Metering provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by Public Service to a Qualified Customer Generator, as defined in Section 15.2, in a given billing period and the electricity delivered by Qualified Customer Generator into the Public Service distribution system. Public Service will select and supply the type of meter(s) that will enable the measurement of the electricity for the billing or crediting of energy delivered as indicated above.

Customers qualified for Net Metering shall be responsible for all interconnection costs as defined in N.J.A.C. 14:8-4.1 *et seq*., which shall be in addition to any line or service extension charge required to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 3, Charges for Service, shall mean net usage as determined by Net Metering.

15.2. **Limitations and Qualifications for Net Metering:** To qualify for Net Metering, a customer-generator must generate Class I renewable energy as defined in N.J.A.C. 14:8-1.2. Further, to qualify for Net Metering, the capacity of the customer's generating system cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to the customer's residence or facility, as applicable, over an annualized period~~; or the customer's generating system is limited to a maximum size of 2 megawatts, whichever is less~~. Customer-generators that qualify for Net Metering shall be referred to as "Qualified Customer-Generators."

Additionally, customers participating in Community Solar cannot participate in Net Metering unless each project is metered separately.

15.3. **Installation Standards:** A Qualified Customer-Generator shall ascertain and comply with the requirements of Public Service which are covered in detail in the "Information and Requirements for Electric Service", available on www.pseg.com or by request as designated in Section 6.3, Secondary Distribution Service, of these Standard Terms and Conditions. In addition, the Qualified Customer-Generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 39**

STANDARD TERMS AND CONDITIONS

(Continued)

Qualified Customer-Generator's generating system shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, accredited testing institutions, such as Underwriters Laboratories. The customer's installation should be made in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply to standards established by Public Service and approved by the New Jersey Board of Public Utilities ("Board") in addition to the aforementioned applicable safety and power quality standards and all other requirements in N.J.A.C. 14:8-4.1 *et seq*.

15.4. Initiation of Service: Prior to interconnecting with the Public Service distribution system the Qualified Customer-Generator is required to provide Public Service with an Interconnection Application provided by the Office of Clean Energy and pay all appropriate charges as detailed in the Interconnection Application Process. Additionally, Public Service may, at its option, inspect the interconnection prior to the initiation of Net Metering service for Qualified Customer-Generators.

Initiation of service will become effective on the Qualified Customer-Generator's first regularly scheduled meter reading date that is at least twenty (20) days after the customer elects this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt of customer notification by Public Service. The Qualified Customer-Generator shall provide Public Service on a regular basis with access to the customer's telephone service when required for the purposes of acquiring metering data.

15.5. Net Billing: Where the amount of electricity delivered by the Qualified Customer-Generator plus any kilowatt-hour credits held over from the previous billing periods exceeds the electricity supplied by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, the Qualified Customer-Generator shall be credited for the excess kilowatt-hours to the next billing period. At the end of the annualized period the Qualified Customer-Generator will be compensated for any remaining credits by the Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, at their avoided cost of wholesale power.

A Qualified Customer-Generator shall have a one-time opportunity to select a monthly billing period as the start of the Qualified Customer-Generator's annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Qualified Customer-Generator notifies Public Service of the selection of their alternate monthly billing period. If a Qualified Customer-Generator initiating service after March 2, 2009 does not submit an annualized period selection they shall be assigned a default annualized period until such time as they notify Public Service of the selection of their alternate annualized period.

In the event that a Qualified Customer-Generator changes suppliers, the electric power supplier or basic service provider with whom service is terminated shall treat the end of the service period as if it were the end of the annualized period. Changes in supplier are to be in accordance with Section 14.2.1, Customer Change of Third Party Supplier, or Section 14.2.2, Customer Returns to Public Service Rate Schedule Electric Supply, of these Standard Terms and Conditions, as applicable.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 40**

STANDARD TERMS AND CONDITIONS
(Continued)

15.6. Billing Adjustments: In addition to Section 9.5, Billing Adjustments, of these Standard Terms and Conditions whenever a meter measuring energy delivered from a Qualified Customer-Generator to Public Service's distribution system is found to be registering slow by 2% or more an adjustment of the energy delivered shall be made and an adjustment may be made if the meter is found to be registering fast by more than 2%. The Qualified Customer-Generator's electric supplier or basic generation service provider, as applicable, will determine the applicability of this latter adjustment.

15.7. Budget Plan (Equal Payment Plan): The payment option described in Section 9.9, Budget Plan, is not available for customers taking service under this Section 15, Net Metering.

15.8. Program Availability: In accordance with N.J.S.A. 48:3-87(e)(1), Public Service may be authorized by the Board to cease offering net metering to customers that are not already net metered whenever the total rated generating capacity owned and operated by net metering customer-generators Statewide equals 5.8 percent of the total annual kilowatt-hours sold in this State by each electric power supplier and each basic generation service provider during the prior one-year period.~~Public Service may be authorized by the Board to cease offering net metering whenever the total rated generating capacity owned and operated by Qualified Customer-Generators Statewide equals 2.5 percent of the State's peak electricity demand.~~

16. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Electric Service.

16.1. New Jersey Sales and Use Tax:
In accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

16.1.1. The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Agencies or instrumentalities of the federal government.

d) International organizations of which the United States of America is a member.

e) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 41**

STANDARD TERMS AND CONDITIONS

(Continued)

16.1.2. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 *et seq.*) and P.L.1966, c.30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

16.2. New Jersey Corporation Business Tax:
In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

16.2.1. The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 42**

STANDARD TERMS AND CONDITIONS

(Continued)

b) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

c) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 43
Original Sheet No. 44
Original Sheet No. 45
Original Sheet No. 46
Original Sheet No. 47

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 48**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

The following are the charges applicable for certain residential underground extensions, in compliance with the Regulations on Residential Underground Extensions as per N.J.A.C. 14:3-8 et seq., and referenced in the Sections 3.~~8~~7.2. – Multi-unit Developments of the Standard Terms and Conditions of this tariff.

The Applicant will be charged for standard electric service as calculated in Section A – Base Charges and/or Section B – Additional Charges. The charges in Sections A and B will be adjusted for tax gross-up effects consistent with all applicable federal and state tax laws, including, but not limited to, the "Protecting Americans from Tax Hikes Act of 2015" ("the PATH Act"). For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction, such result shall include the gross-up for income tax effects. Such cost estimates shall be based on the unit costs as detailed in Exhibits I to III and shall be based on the necessary construction to supply the same loads and locations utilizing Public Service's standard design and construction standards. Requests for additional facilities shall be considered as Atypical Conditions and other charges may apply in accordance with Section 3.5.2 of these Standard Terms and Conditions.

Charges for street and area lighting provided by Public Service under Rate Schedules PSAL or BPL are as indicated in Section C – Street and Area Lighting Charges.

A. Base Charges:

		Charge Per Building Lot	Charge Per Foot For Total Front Footage
1.	Single-family	$ 529.43	$ 1.43
2.	Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase, high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 kVA, etc.	Charge to be based on differential cost according to unit costs specified in Exhibit I to III.	

B. Additional Charges:

	Item	Unit	Charge
1.	Primary termination.....	Each	$ 310.57
2.	Primary junction enclosure	Each	$ 1,639.80
3.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
4~~3~~.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
	.....	Over 150 amp	$ 6.37
5~~3~~.	Excess service length over 50 feet.....	Per foot trench 100 & 150 amp	$ 5.47
6~~4~~.	Multi-phase constructions.....	Per foot per phase	$ (3.90)
7~~5~~.	Pavement cutting and restoration, rock removal, blasting, difficult digging and special backfill	At actual low bid cost with option of Applicant to contract for as limited by N.J.A.C. 14:5-2.4 et seq.	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 49**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)

C. Street and Area Lighting Charges:

The Applicant shall pay the normal charges for all luminaires as indicated in the applicable street and area lighting rate schedule.

The monthly charge and up-front contribution for all lighting poles not installed on public streets shall be at the full charges indicated in the applicable street and area lighting rate schedule.

1. Street lighting~~Streetlighting~~ poles where spacing is equal to or greater than 200 feet.

   For street and area lighting poles installed on public streets, PSE&G will provide, as the standard lighting pole, a laminated wood pole (PSE&G part number W04-0197) at no up-front contribution or monthly charge. Requests for use of another type or size lighting pole shall be considered as a request for a Specialty Lighting Pole. In these cases, an up-front contribution credit equal to the installed cost of the standard lighting pole shall be provided by Public Service, with monthly charges calculated as per the applicable street and area lighting rate schedule.

2. Additional street lighting poles where spacing is less than 200 feet.

   The Applicant shall pay the full normal charges for lighting poles as indicated in the applicable street and area lighting rate schedule where the spacing of such lighting poles is less than 200 feet.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 50**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT I - UNIT COSTS OF UNDERGROUND CONSTRUCTION - SINGLE PHASE

	Item	Unit	Total Charge*
1.	Trenching		
	Sole Trenching	Per foot	$ 2.22
	Joint Trenching**	Per foot	$ 1.28
2.	Primary cable (1/0 AWG Al.)	Per foot	$ 3.93~~2.30~~
3.	Secondary wire		
	2/0 AWG Cu	Per foot	$ 3.59
	350 kcmil Cu	Per foot	$ 10.75
4.	Services		
	~~50 feet complete - 100 & 150 amp~~	~~Each~~	~~$ 552.58491.02~~
	100 & 150 amp (#2 AWG Cu.)	Per foot	$11.05~~10.10~~
	~~50 feet complete - over 150 amp~~	~~Each~~	~~$ 675.06~~
	~~50 feet complete~~	~~Each~~	~~$ 491.02~~
	Service - over 150 amp (2/0 AWG Cu.)	Per foot	$13.50~~13.78~~
	~~50 feet complete~~	~~Each~~	~~$ 675.06~~
5.	Primary termination - branch	Each	$ 1,563.94~~232.81~~
6.	Primary junction enclosure - branch	Each	$ 2,294.67~~1,639.80~~
7.	Secondary enclosure	Each	$ 692.09
~~8.~~	~~Conduit~~		
	~~1 - 4 inch conduit~~	~~Per foot~~	~~$ 5.19~~
	~~2 - 4 inch conduits~~	~~Per foot~~	~~$ 6.62~~
	~~3 - 4 inch conduits~~	~~Per foot~~	~~$ 8.83~~
	~~4 - 4 inch conduits~~	~~Per foot~~	~~$ 11.03~~
~~9~~8.	Street light cable (#8 AWG Cu.)	Per foot	$ 4.32~~2.11~~
~~10~~9.	Transformers - including fiberglass pad		
	25 kVA - single-phase	Each	$1,376.93~~1,664.63~~
	50 kVA - single-phase	Each	$5,290.64~~1,879.14~~
	75 kVA - single-phase	Each	$5,645.29~~2,239.50~~
	100 kVA - single-phase	Each	$6,285.68~~2,417.06~~
	167 kVA - single-phase	Each	$3,632.41~~3,016.82~~
~~11~~10.	Street light poles (standard pole only)		
	30 foot ~~center bored pine wood pole~~laminated pole	Each	$1,100.00~~842.20~~

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

** Joint trench calculation: 0.5 (0.85 x $2.22) + 0.15 x $2.22 =$1.28

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 51**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS
(Continued)
EXHIBIT II - UNIT COSTS OF UNDERGROUND CONSTRUCTION - THREE-PHASE

	Item	Unit	Total Charge*
1.	Primary cable		
	750 kcmil Cu.	Per foot	$ 25.24
	500 kcmil Cu.	Per foot	$ 17.92
	4/0 AWG Al.	Per foot	$ 12.62
	1/0 AWG Al.	Per foot	$ 7.06
2.	Secondary 4-wire (350 kcmil Cu.)	Per foot	$ 11.34
~~3.~~	~~Service 4-wire (350 kcmil Cu.)~~	~~Per foot~~	~~$ 13.39~~
~~4~~3.	Primary Terminations		
	Main line (750 kcmil)	Set of 3	$3,387.34~~1,676.68~~
	Three phase branch (500 kcmil)	Set of 3	$ 785.25
	Two phase branch (4/0 AWG)	Set of 2	$ 425.38
~~5.~~	~~Three Phase Primary Switches~~		
	~~Switch with fused taps~~	~~Each~~	~~$ 15,918.85~~
	~~Junction with fused taps~~	~~Each~~	~~$ 9,410.52~~
	~~Junction without fused taps~~	~~Each~~	~~$ 6,304.55~~
~~6~~4.	5 inch conduit	Per foot	$ 6.27~~5.87~~
	6 inch conduit	Per foot	$ 8.20
~~7~~5.	Transformers - including fiberglass pad		
	150 kVA - three-phase	Each	$11,158.06~~5,683.32~~
	225 kVA - three-phase	Each	$10,085.50~~7,697.69~~
	300 kVA - three-phase	Each	$20,902.25~~7,929.33~~
	500 kVA - three-phase	Each	$23,728.71~~9,833.99~~
	700 kVa - three-phase	Each	$ 22,574.76
	1000 kVa - three-phase	Each	$ 34,287.53
	1500 kVa - three-phase	Each	$ 38,672.75

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 52**

REGULATION FOR RESIDENTIAL UNDERGROUND EXTENSIONS

(Continued)

EXHIBIT III - UNIT COSTS OF OVERHEAD CONSTRUCTION

SINGLE-PHASE AND THREE-PHASE

	Item	Unit	Total Charge*
1.	Pole line - including 7-35 foot and 2-40 foot poles, anchors and guys per 1000 feet	Per foot	$ 6.48**
2.	Primary wire		
	1/0 AWG AAAC covered, one phase	Per foot	$ 7.25
	379.5 kcmil Al. covered, three phase	Per foot	$ 11.11
	1/0 AWG AAAC base, one phase	Per foot	$ 7.30
	379.5 kcmil Al. bare, three phase	Per foot	$ 10.85
3.	Primary wire neutral (1/0 AWG AAAC)	Per foot	$ 2.76
4.	Secondary cable		
	3 wire (2/0 AWG Al.)	Per foot	$ 5.164.03
	4 wire (2/0 AWG Al.)	Per foot	$ 8.454.63
5.	Services - single-phase		
	50 feet complete - 100 & 150 amp	Each	$ 259.25
	100 & 150 amp (#2 AWG Al.)	Per foot	$ 5.19
	~~50 feet complete~~	~~Each~~	~~$ 259.25~~
	50 feet complete - over 150 amp	Each	$ 379.01
	Over 150 amp (2/0 AWG Al.)	Per foot	$ 7.58
	~~50 feet complete~~	~~Each~~	~~$ 379.01~~
	Services - three-phase		
	up to 200 amp (2/0 AWG Al.)	Per foot	$ 7.76
	over 200 amp (397.5 kcmil Al.)	Per foot	$ 12.27
6.	Transformers		
	25 kVA - single-phase	Each	$1,376.931,201.13
	50 kVA - single-phase	Each	$5,285.991,356.16
	100 kVA - single-phase	Each	$6,239.622,183.32
	3 - 25 kVA - three-phase	Per set	$ 2,961.53
	3 - 50 kVA - three-phase	Per set	$ 3,690.83
	3 - 100 kVA - three-phase	Per set	$ 5,721.66

*Charges do not include costs for clerical, dispatching, supervision, or general office functions as, except for third-party damage or other actions by third-parties, those costs are considered legitimate costs of doing business and incurred as part of the Company's normal operations in meeting its regulatory duty to furnish service.

**Joint pole line cost to be used = $3.23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 53
Original Sheet No. 54
Original Sheet No. 55
Original Sheet No. 56

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 57**

SOCIETAL BENEFITS CHARGE

	Cost Recovery (per kilowatt-hour)
Component:	
Social Programs	$ 0.001728
Energy Efficiency and Renewable Energy Programs	0.003287
Manufactured Gas Plant Remediation	0.000471
Sub-total per kilowatt-hour	$ 0.005486

Charge including losses, USF and Lifeline:

	Loss Factor	Sub-total Including Losses	USF	Lifeline	Total Charge
Secondary Service	5.8327%	$ 0.005826	$ 0.001243	$ 0.000698	$ 0.007767
LPL Primary	3.3153%	0.005674	0.001243	0.000698	0.007615
HTS Subtransmission	2.0472%	0.005601	0.001243	0.000698	0.007542
HTS High Voltage & HTS Transmission	0.8605%	0.005534	0.001243	0.000698	0.007475

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	$ 0.008282
LPL Primary	0.008119
HTS Subtransmission	0.008042
HTS High Voltage & HTS Transmission	0.007970

SOCIETAL BENEFITS CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge.

(Charges are for illustrative purposes only and are based on the Tenth Revised Sheet No. 57 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 58**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This component shall recover costs associated with existing social programs. This includes but is not limited to uncollectible customers' accounts.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

The New Jersey Clean Energy Program energy efficiency and renewable energy programs (formerly CRA Programs) are approved by the Board pursuant to N.J.S.A. 48:3-60(a)(3). They include energy efficiency programs, customer-sited renewable energy programs, grid supply renewable energy programs and any other programs the BPU may approve. These programs may be administered and or implemented by Public Service, the BPU, or a third party appointed by the BPU. New Jersey Clean Energy Program Costs consist of, but are not limited to, rebates, grants, payments to third parties for program implementation, direct marketing costs, energy efficiency and renewable energy hardware, administration, measurement and evaluation of energy efficiency and renewable energy programs, customer communication and education, market research, costs associated with developing, implementing and obtaining regulatory approval, costs of research and development activities associated with energy efficiency and renewable energy programs, applicable Lost Revenues, and New Jersey Clean Energy Program advertising costs.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 59**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 60**

NON-UTILITY GENERATION CHARGE

	Cost Recovery (per kilowatt-hour)		
	St Lawrence NYPA Credit RS, RHS and RLM	**Non-Utility Generation above market costs**	**Total**
Total Cost per kilowatt-hour		$0.000023	
Amount per kilowatt-hour of cost recovery after application of losses:			
RS, RHS & RLM (Loss Factor =5.8327%)	($ 0.000000)	$0.000024	$0.000024
Other Secondary (Loss Factor =5.8327%)		0.000024	0.000024
LPL Primary (Loss Factor =3.3153%)		0.000024	0.000024
HTS Subtransmission (Loss Factor =2.0472%)		0.000023	0.000023
HTS High Voltage & HTS Transmission (Loss Factor =0.8605%)		0.000023	0.000023
Charges including New Jersey Sales and Use Tax (SUT)			
RS, RHS & RLM	($ 0.000000)	$0.000026	$0.000026
Other Secondary Service		0.000026	0.000026
LPL Primary		0.000026	0.000026
HTS Subtransmission		0.000025	0.000025
HTS High Voltage & HTS Transmission		0.000025	0.000025

NON-UTILITY GENERATION CHARGE

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. This charge shall recover: 1) above market costs associated with non-regulated generation costs which are related to long-term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978 and 2) other generation costs as may be approved by the Board. Actual costs incurred by the Company will be subject to deferred accounting. The St. Lawrence New York Power Authority (NYPA) Annual Benefit Allocation credit reflects the annual Economic Benefit allocation for New Jersey's investor owned utilities to supply residential customers' load.

Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered Non-utility Generation above market cost balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 61**

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

	Charge (per kilowatt-hour)
ZERO EMISSION CERTIFICATE RECOVERY CHARGE:	
Charge	$ 0.004000
Return of Excess Collections	$ 0.000000
Total Charge	$ 0.004000
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.004265

ZERO EMISSION CERTIFICATE RECOVERY CHARGE

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below.
Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091004, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per kWh for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c. 16 ("ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC Law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate, interest-bearing account and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in Docket No. EO18080899.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 62
Original Sheet No. 63

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 64**

SOLAR PILOT RECOVERY CHARGE

	Charge (per kilowatt-hour)
SOLAR PILOT RECOVERY CHARGE:	
Charge	$ 0.000063
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000067

SOLAR PILOT RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery by the Company is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances. This interest rate shall change each August 1.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 64 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 65**

GREEN PROGRAMS RECOVERY CHARGE

Component:	**Charge (per kilowatthour)**
Carbon Abatement Program	($0.000010)
Energy Efficiency Economic Stimulus Program	0.000004
Solar Generation Investment Program	0.000297
Solar Loan II Program	0.000109
Energy Efficiency Economic Extension Program	0.000034
Solar Generation Investment Extension Program	(0.000222)
Solar Loan III Program	0.000015
Energy Efficiency Economic Extension Program II	0.000108
Solar Generation Investment Extension II Program	(0.000105)
Energy Efficiency 2017 Program	0.000268
Transition Renewable Energy Certificate Program	0.002480
Clean Energy Future - Energy Efficiency Program	0.001257
Successor Solar Incentive Program	0.000601
Community Solar Energy Program	0.000084
Sub-total per kilowatthour	$0.004920
Charge including New Jersey Sales and Use Tax (SUT)	$0.005246

GREEN PROGRAMS RECOVERY CHARGE

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 61 filed with the BPU on November 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO RATE SCHEDULES RS, RHS, RLM, GLP, LPL-S

	Conservation Incentive Program	Conservation Incentive Program including SUT	
RS & RHS	$0.000271	$0.000289	Per kilowatt-hour
RLM	$0.000965	$0.001029	Per kilowatt-hour
GLP	$1.2193	$1.3001	Per kilowatt of monthly peak demand
LPL-S	$1.0290	$1.0972	Per kilowatt of monthly peak demand

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed revenue per customer during the preceding annual period. The Conservation Incentive Program mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company's books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Revenue Per Customer
– the Actual Revenue per Customer ("ARC") shall be determined in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges as well as any Infrastructure Investment Program revenues, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from June 1 of one calendar year through May 31 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 66 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

6. Baseline Revenue per Customer
– the Baseline Revenue per Customer ("BRC") shall be stated in dollars per customer on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BRC shall be calculated as the current variable margin revenue per rate schedule, including any revenue from Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approve base rate case for the rate schedule. Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges, and shall not include the Service Charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charges, Green Programs Recovery Charges, or the Tax Adjustment Credit.

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I: RS & RHS
Group IA: RLM
Group II: GLP
Group III: LPL-S

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Degree Days (DD)
– the difference between 65^{o}F and the mean daily temperature. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day. Heating Degree Days (HDD) are used to measure winter weather.

10. Temperature Humidity Index (THI)
– a measure of the degree of discomfort experienced by an individual in warm weather that includes temperature and humidity which is included by incorporating the dew point in the measure. The daily THI is the sum of the 24 hourly THI observations for a day. THI is used to measure summer weather.

11. Actual Calendar Month HDD and THI
– the accumulation of the actual HDD and THI for each day of a calendar month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

12. Normal Calendar Month HDD and THI
– the level of calendar month HDD and THI to which the weather portion of this CIP applies.

The normal calendar month HDD and THI will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Newark airport and will be updated annually. The base level of normal HDD and THI for the defined winter and summer period months for the 2022-2023 Periods are set forth in the table below:

Month	Normal Heating Degree Days	Normal Temperature Humidity Index
January 2023	989	
February 2023	838	
March 2023	684	
April 2023	354	187
May 2023	128	931
June 2022		3,043
July 2022		5,624
August 2022		4,861
September 2022		2,237
October 2022	228	414
November 2022	523	
December 2022	816	

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

14. Summer Period
– shall be the seven consecutive calendar months from April of one calendar year through October of the calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

15. Consumption Factors
– the use per HDD and THI component by month used in forecasting sales for the applicable rate schedules. These factors will be updated annually. Consumption Factors for the 2022-2023 Winter Period for HDD and 2022 Summer Period for THI are set forth below and presented as kWh per degree day:

	Consumption Factors (kWh per HDD and THI)					
	RS		RHS		RLM	
Month	HDD	THI	HDD	THI	HDD	THI
January 2023	469,298	150,909	11,303	409	6,341	1,577
February 2023	469,294	150,908	11,258	407	6,286	1,563
March 2023	469,288	150,906	11,276	408	6,207	1,543
April 2023	469,533	150,984	11,219	406	6,200	1,541
May 2023	469,777	151,063	11,163	404	6,193	1,540
June 2022	463,870	149,164	11,707	423	6,341	1,577
July 2022	461,601	148,434	11,568	418	6,287	1,563
August 2022	460,471	148,070	11,545	418	6,588	1,638
September 2022	461,466	148,390	11,469	415	6,061	1,507
October 2022	460,832	148,186	11,445	414	6,172	1,534
November 2022	461,133	148,283	11,350	410	6,412	1,594
December 2022	462,271	148,649	11,347	410	6,289	1,563

II. BASELINE REVENUE PER CUSTOMER

– the BRC for each Customer Class Group by month are as follows:

Month	RS & RHS	RLM	GLP	LPL-S
Jun	$32.30	$90.17	$130.32	$2,691.79
Jul	39.76	102.12	150.23	3,943.65
Aug	36.78	95.84	145.41	3,981.31
Sep	22.10	43.79	90.80	2,236.34
Oct	13.79	17.31	54.66	1,623.92
Nov	14.98	15.85	48.76	1,008.96
Dec	18.58	20.42	48.68	863.90
Jan	20.61	22.23	52.13	926.21
Feb	17.06	19.36	49.77	928.65
Mar	16.39	18.57	49.83	930.16
Apr	13.98	14.68	49.36	886.19
May	15.43	18.93	87.85	1,721.67
Total Annual	**$261.75**	**$479.26**	**$957.80**	**$21,742.74**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 66D**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers.

2. The weather related change in customer usage shall be calculated as the difference between actual HDD and THI and the above HDD and THI multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 67**

DISTRIBUTION ADJUSTMENT CHARGE

	Charge (per kilowatthour)
Component:	
Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Charge including New Jersey Sales and Use Tax (SUT)	$0.XXXXXX

DISTRIBUTION ADJUSTMENT CHARGE

This non-bypassable charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

~~**Original Sheet No. 67**~~
Original Sheet No. 68

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 69**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per kilowatt-hour	Charge per kilowatt-hour Including SUT
RS	($0.005250)	($0.005598)
RHS	($0.006603)	($0.007040)
RLM	($0.004760)	($0.005075)
WH	($0.000000)	($0.000000)
WHS	($0.000000)	($0.000000)
HS	($0.003743)	($0.003991)
GLP	($0.001622)	($0.001729)
LPL – Secondary	($0.000929)	($0.000991)
LPL – Primary	($0.000600)	($0.000640)
HTS – Subtransmission	($0.000563)	($0.000600)
HTS – High Voltage & HTS – Transmission	($0.000224)	($0.000239)
BPL	($0.000000)	($0.000000)
BPL-POF	($0.001418)	($0.001512)
PSAL	($0.000000)	($0.000000)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 69 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 70**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RS					
Service Charge	per Month	$4.95	$0.00	$0.00	$4.95
Distribution 0-600, June-September	per kWhr	0.040752	0.007484	0.007980	0.048732
Distribution 0-600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
Distribution over 600, June-September	per kWhr	0.044826	0.007484	0.007980	0.052806
Distribution over 600, October-May	per kWhr	0.035553	0.000000	0.000000	0.035553
RHS					
Service Charge	per Month	4.95	0.00	0.00	4.95
Distribution 0-600, June-September	per kWhr	0.051834	0.004222	0.004501	0.056335
Distribution 0-600, October-May	per kWhr	0.034956	0.001935	0.002063	0.037019
Distribution over 600, June-September	per kWhr	0.057058	0.004222	0.004502	0.061560
Distribution over 600, October-May	per kWhr	0.016190	0.001935	0.002063	0.018253
Common Use	per kWhr	0.057058	0.004222	0.004502	0.061560
RLM					
Service Charge	per Month	13.94	0.00	0.00	13.94
Distribution, June-September, On-Peak	per kWhr	0.075220	0.006391	0.006814	0.082034
Distribution, June-September, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, On-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
Distribution, October-May, Off-Peak	per kWhr	0.015703	0.001335	0.001423	0.017126
WH					
Distribution	per kWhr	0.050538	0.002084	0.002222	0.052760
WHS					
Service Charge	per Month	0.63	0.04	0.04	0.67
Distribution	per kWhr	0.001722	0.000310	0.000331	0.002053

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 70 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 71**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HS					
Service Charge	per Month	$3.74	$0.24	$0.26	$4.00
Distribution, June-September	per kWhr	0.102660	0.001730	0.001844	0.104504
Distribution, October-May	per kWhr	0.030703	0.000631	0.000672	0.031375
GLP					
Service Charge	per Month	4.77	0.31	0.33	5.10
Service Charge-Unmetered	per Month	2.21	0.13	0.14	2.35
Service Charge-Night Use	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.9378	0.0729	0.0777	4.0155
Summer Demand, June-September	per kW	9.8746	0.1830	0.1952	10.0698
Distribution, June-September	per kWhr	0.003219	0.000060	0.000064	0.003283
Distribution, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, June-September	per kWhr	0.008217	0.000152	0.000162	0.008379
Distribution-Night Use, October-May	per kWhr	0.008217	0.000152	0.000162	0.008379
LPL-Secondary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Annual Demand	per kW	3.7617	0.0944	0.1007	3.8624
Summer Demand, June-September	per kW	8.9495	0.2245	0.2393	9.1888
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
LPL-Primary					
Service Charge	per Month	370.81	0.00	0.00	370.81
Service Charge-Primary Alternate	per Month	21.54	1.38	1.47	23.01
Annual Demand	per kW	1.7531	0.0443	0.0473	1.8004
Summer Demand, June-September	per kW	9.7321	0.2457	0.2620	9.9941
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 71 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 72**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES
(Continued)

Rate Schedule		Base Distribution Charges Including SUT	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
HTS-Subtransmission					
Service Charge	per Month	$2,038.02	$0.00	$0.00	$2,038.02
Annual Demand	per kW	1.1432	0.0720	0.0768	1.2200
Summer Demand, June-September	per kW	4.1326	0.2603	0.2775	4.4101
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
HTS-High Voltage					
Service Charge	per Month	1,834.22	0.00	0.00	1,834.22
Annual Demand	per kW	0.6574	0.0156	0.0167	0.6741
Distribution	per kWhr	0.000000	0.000000	0.000000	0.000000
BPL					
Distribution	per kWhr	0.007181	0.000159	0.000170	0.007351
BPL-POF					
Distribution	per kWhr	0.007174	0.000203	0.000216	0.007390
PSAL					
Distribution	per kWhr	0.007660	0.000171	0.000182	0.007842

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Fourth Revised Sheet No. 72 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Original Sheet No. 73 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 74**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May: Energy & Capacity Charges	For usage in each of the months of October through May: Charges Including SUT	For usage in each of the months of June through September: Energy & Capacity Charges	For usage in each of the months of June through September: Charges Including SUT
RS – first 600 kWh	$ 0.075527	$ 0.080531	$ 0.072237	$ 0.077023
RS – in excess of 600 kWh	0.075527	0.080531	0.081381	0.086772
RHS – first 600 kWh	0.076746	0.081830	0.068808	0.073367
RHS – in excess of 600 kWh	0.076746	0.081830	0.081036	0.086405
RLM On-Peak	0.089221	0.095132	0.094156	0.100394
RLM Off-Peak	0.064475	0.068746	0.059459	0.063398
WH	0.068204	0.072723	0.066577	0.070988
WHS	0.066441	0.070843	0.066429	0.070830
HS	0.078509	0.083710	0.075325	0.080315
BPL	0.066509	0.070915	0.061239	0.065296
BPL-POF	0.066509	0.070915	0.061239	0.065296
PSAL	0.066509	0.070915	0.061239	0.065296

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fourteenth Revised Sheet No. 75 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 76**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

Rate Schedule	For usage in all months Transmission Charges	 Charges Including SUT
RS	$0.057428	$0.061233
RHS	0.037541	0.040028
RLM On-Peak	0.124829	0.133099
RLM Off-Peak	0.000000	0.000000
WH	0.000000	0.000000
WHS	0.000000	0.000000
HS	0.047976	0.051154
BPL	0.000000	0.000000
BPL-POF	0.000000	0.000000
PSAL	0.000000	0.000000

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May Charges	 Charges Including SUT	For usage in each of the months of June through September Charges	 Charges Including SUT
GLP	$0.067068	$0.071511	$0.067343	$0.071804
GLP Night Use	0.063526	0.067735	0.059237	0.063161
LPL-Sec. under 500 kW				
On-Peak	0.070936	0.075636	0.075223	0.080207
Off-Peak	0.063526	0.067735	0.059237	0.063161

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Fifteenth Revised Sheet No. 76 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 77
Original Sheet No. 78

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$ 1.6327
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.7409
Charge applicable in the months of October through May	$ 1.6327
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.7409

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.
Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 79 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 80**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 81**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge	$(0.006791)
Charge including New Jersey Sales and Use Tax (SUT)	$(0.007241)

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 81 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.79690%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$10.0663
Charge including New Jersey Sales and Use Tax (SUT)	$10.7332
Charges applicable in the months of October through May	$10.0663
Charges including New Jersey Sales and Use Tax (SUT)	$10.7332

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 82 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 142,957.59 per MW per year
EL05-121	$ 77.54 per MW per month
FERC 680 & 715 Reallocation	$ 0.00 per MW per month
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 52.61 per MW per month
Virginia Electric and Power Company	$ 63.65 per MW per month
Potomac-Appalachian Transmission Highline L.L.C	$ 0.49 per MW per month
PPL Electric Utilities Corporation	$ 181.69 per MW per month
American Electric Power Service Corporation	$ 17.58 per MW per month
Atlantic City Electric Company	$ 8.46 per MW per month
Delmarva Power and Light Company	$ 1.28 per MW per month
Potomac Electric Power Company	$ 2.70 per MW per month
Baltimore Gas and Electric Company	$ 3.89 per MW per month
Jersey Central Power and Light	$ 60.23 per MW per month
Mid Atlantic Interstate Transmission	$ 18.06 per MW per month
PECO Energy Company	$ 23.93 per MW per month
Silver Run Electric, Inc	$ 44.16 per MW per month
Northern Indiana Public Service Company	$ 0.73 per MW per month
Commonwealth Edison Company	$ 0.13 per MW per month
South First Energy Operating Company	$ 0.66 per MW per month
Duquesne Light Company	$ 0.33 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.4713
Charge including New Jersey Sales and Use Tax (SUT)	$ 13.2975

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

(Charges are for illustrative purposes only and are based on the Eighteenth Revised Sheet No. 83 filed with the BPU on November 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 84**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS RECONCILIATION CHARGES:

Charges per kilowatthour:

Basic Generation Service Reconciliation Charge	$0.003332
Charge including New Jersey Sales and Use Tax (SUT)	$0.003553

The above charges shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are updated quarterly. These charges shall be combined with the BGS Energy Charges for billing.

(Charges are for illustrative purposes only and are based on the Fortieth Revised Sheet No. 84 filed with the BPU on August 15, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 85
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 87**

THIRD PARTY SUPPLIER

APPLICABLE TO:

A third party supplier is an entity that has executed a Third Party Supplier Agreement (Agreement) with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. This Agreement sets forth the specific terms and conditions with which Third Party Suppliers must comply to use Public Service's distribution system to supply energy to retail customers in Public Service's service territory. This Agreement is standardized in form and will apply in an equal and uniform manner to all Third Party Suppliers requesting to provide competitive energy supply to retail customers in Public Service's service territory. The Agreement is hereby incorporated by reference herein, and similarly incorporates this Tariff for Electric Service in its terms.

All modifications to the Agreement must be approved by the Board, consistent with the process set forth below, prior to implementation. Any such modifications, other than Third Party Supplier fee changes, shall be undertaken in accordance with the following procedures. Specifically, Public Service may amend the Agreement by providing simultaneous written notice of such change, by regular mail, ~~facsimile, hand delivery,~~ or electronic means, to the Board of Public Utilities (Board), Division of Ratepayer Advocate (RPA), Jersey Central Power and Light, Atlantic City Electric Company, Rockland Electric and to Third Party Suppliers licensed as Electric Power Suppliers in New Jersey, a list of which will be provided by the Board. Within seventeen (17) days of such notice, the RPA or any New Jersey licensed Electric Power Supplier wishing to contest the amendment of the Agreement must submit in writing to the Board its reason for contesting the change, and must simultaneously provide a copy of such document to Public Service. Within forty-five (45) days of such notice, the Board may either (i) approve the amendment; (ii) determine through a suspension order that the proposed amendment needs further study, and thus place the request on hold pending future action by the Board; or (iii) take no action, in which case Public Service may implement the amendment at the conclusion of the forty-five (45) day period; provided, however, that the Board is not thereby precluded from taking action on the amendment in the future.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 88
Original Sheet No. 89
Original Sheet No. 90
Original Sheet No. 91
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 93 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour for RS non-Time of Use (TOU) customers:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.045704	$ 0.048732

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.033344	$ 0.035553	$ 0.049525	$ 0.052806

Distribution Charges per Kilowatt-hour for RS TOU customers (see Special Provision (a-8) for details)

For customers selecting two-period option (TOU-2P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	10 pm - 11 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

For customers selecting three-period option (TOU-3P):

		June through September		October through May	
		Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	4 pm - 9 pm (weekdays)*	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Mid-Peak	All other times	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX
Off-Peak	Midnight - 6 am	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX	$ X.XXXXXX

* Weekdays exclude PJM holidays.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231 EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 94**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 95**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge. ~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 96 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service, provided that the number of kilowatt-hours in each block of the Distribution Charge are multiplied by the number of individual flats or apartments, whether occupied or not.;

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use. This provision is only available to customers receiving this service under special provision (d);

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles. This provision is only available to customers receiving this service under special provision (d);

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.

(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(d-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.

(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.

(d-4) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.

(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.

(e-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 97 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

~~(d) **Electric Vehicle Distribution Only:** Based upon the following eligibility criteria, residential customers may elect to receive on-peak and off-peak distribution energy charges from the Residential Load Management (RLM) rate schedule exclusively for their electric vehicle usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the RS rate. All other provisions of this tariff will remain in effect.~~

~~(d-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.~~

~~(d-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the Rate Schedule RLM distribution rates less the electric vehicle usage billed at Rate Schedule RS distribution rates for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the RS distribution rates, no adjustment for the corresponding period will be applied.~~

~~(d-3) For ratemaking purposes, the electric vehicle RLM Distribution Only Provision credits associated with this special provision will be reflected as a reduction to the Rate Schedule RS distribution revenue. The credit will be applied at least quarterly to the customer bill and will indicate the corresponding period(s) for which the credit applies.~~

~~(d-4) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.~~

~~(e) **Electric Vehicle Basic Generation Supply (BGS) Customers Only**: Based upon the following eligibility criteria, residential customers who receive their electric supply via BGS may elect to receive on-peak and off-peak supply charges based on BGS rates applicable to Rate Schedule Residential Load Management (RLM) exclusively for their electric vehicle charging usage. This option, upon Company approval into the program, will be issued as a credit on the customer bill on at least a quarterly basis, after the entire usage has been billed at the BGS rates applicable to Rate Schedule RS. All other provisions of this tariff will remain in effect.~~

~~(e-1) A customer taking service under this special provision must install or utilize PSE&G approved smart charging hardware and network technology. The customer must also agree to share the Electric Vehicle Charging Data with PSE&G in a manner specified by PSE&G. Data must be available to the Company and necessary billing system changes must be in place in order for these incentives to begin.~~

~~(e-2) The electric vehicle credit will be calculated by the Company's program administrator at least quarterly using the electric vehicle usage at the BGS rates applicable to Rate Schedule RLM less the electric vehicle usage billed at the BGS rates applicable to Rate Schedule RS for the corresponding billing period. If the credit calculation results in charges that would be in excess of the bill calculated using the BGS rates applicable to Rate Schedule RS, no adjustment for the corresponding period will be applied.~~

(d) **Residential Time of Use**: RS customers may elect to take the RS TOU rate.

(d-1) Such customers will be required to stay on the RS TOU rate for a minimum of twelve (12) months.

(d-2) At the end of the initial 12-month period, the Company will provide the customer with reporting showing their 12-month bill on the new RS TOU rate and what their 12-month bill would have been on the non-TOU RS rate schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS TOU rate was higher

compared to the RS rate schedule. This provision ~~applies~~is available only to customers who enroll in RS TOU rates during the first twenty-four (24) months ~~of the implementation of the RS TOU rate~~following the effective date of this tariff provision..

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP - Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98**

RATE SCHEDULE RS

RESIDENTIAL SERVICE

(Continued)

(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 98 for Future**

RATE SCHEDULE RS
RESIDENTIAL SERVICE
(Continued)

~~(e-3) This special provision will remain in effect until the conclusion of the Company's Next Base Rate Case.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 99**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to residential purposes where electricity is the sole source of space heating for customers at their current premise that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.64 in each month [$4.95 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

First 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.034719	$ 0.037019	$ 0.052835	$ 0.056335

In excess of 600 hours used in each of the months of:

October through May		June through September	
Charge	Charge Including SUT	Charge	Charge Including SUT
$ 0.017119	$ 0.018253	$ 0.057735	$ 0.061560

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 100**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge ~~and~~, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RHS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 101**

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
(Continued)

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **General Limitations on Service:** This rate schedule is available where space heating equipment is permanently installed and is operated at not less than 208 volts and where all service is measured by one meter, except for service provided under Rate Schedules WH and WHS:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 102**

RATE SCHEDULE RHS

RESIDENTIAL HEATING SERVICE

(Continued)

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In individual apartments in a multiple-family building;

(a-3) In all-electric multiple-family building where electricity is furnished to the tenants as an incident to tenancy and is included in the rent, provided that the number of kilowatt-hours in each block of the Kilowatt-hour Charge are multiplied by the number of individual flats or apartments, whether occupied or not;

(a-4) Common-use equipment in an all electric multiple-family building in which each tenant is served individually under this rate schedule. The Distribution Charge for the kilowatt-hours used in each month shall be $0.057735 per kilowatt-hour ($0.061560 including SUT).

(b) **Limitations on Water Heating Service:** When electricity is used for water heating under this rate schedule, such service shall be to an automatic type water heater approved by Public Service; furthermore, if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time.

If water is centrally heated under (a-4), equipment shall be of an automatic type approved by Public Service, and billing under this rate schedule is not required.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(d-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(d-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 103
Original Sheet No. 104

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 105 for Future**

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service for residential purposes. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$13.07 in each month [$13.94 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

	In each of the months of October through May		In each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
On-Peak	$ 0.016062	$ 0.017126	$ 0.076937	$ 0.082034
Off-Peak	$ 0.016062	$ 0.017126	$ 0.016062	$ 0.017126

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 106**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule RLM.

MINIMUM CHARGE:

The minimum charge shall be equal to the monthly Service Charge.~~Where all or part of the electricity utilized by the customer is produced from on-site generation equipment and not delivered by Public Service, a Monthly Minimum charge of $2.95 ($3.15 including SUT) per kW of Measured Peak Demand. The customer's Measured Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval as registered by a demand meter furnished by Public Service. Revenue to satisfy the Monthly Minimum requirement shall be derived solely from Distribution Kilowatt-hour Charges.~~

~~This Minimum Charge shall not apply to Qualified Customer-Generators as defined in the Standard Terms and Conditions Section 15.2 in accordance with N.J.A.C. 14:8-4.3(n).~~

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 107**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available where all service is measured by one meter, except for service provided under Rate Schedules WH or WHS:

(a-1) In individual residences and appurtenant outbuildings;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 108 for Future**

RATE SCHEDULE RLM

RESIDENTIAL LOAD MANAGEMENT SERVICE

(Continued)

(a-2) In residential premises where customer's use of electric service for purposes other than residential is incidental to its residential use;

(a-3) On residential farms;

(a-4) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-5) To a customer in a two- or three-family building who has the service for incidental common-use equipment registered on its meter;

(a-6) In individual flats or apartments in multiple-family buildings;

(a-7) In multiple-family buildings of two or more individual flats or apartments where electric service is furnished to the tenants or occupants of the flats or apartments by the owner without a specific charge for such service;.

(a-8) In multiple-family buildings of two or more individual flats or apartments where a dedicated parking space is available and where a customer is served on a separate meter for electric vehicle charging use;

(a-9) In detached garage on a residential parcel for the purposes of charging electric vehicles.

(a-10) **Multi-Family Residential Electric Vehicle Charging:** Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 109
Original Sheet No. 110

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 111**

RATE SCHEDULE WH
WATER HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to premises with controlled water heating installations that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Distribution Charges per Kilowatt-hour:

For all use during the controlled heating period	
Charge	Charge Including SUT
$ 0.049482	$ 0.052760

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 112**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WH.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 113**

RATE SCHEDULE WH
WATER HEATING SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Electricity used for water heating during periods other than the controlled heating periods shall be registered on the meter measuring customer's other use and shall be billed under the rate schedule applicable to such other service;

(a-4) Service for controlled water heating will be controlled by a time switch and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 114**

RATE SCHEDULE WH

WATER HEATING SERVICE

(Continued)

(a-7) Public Service shall furnish, install, and maintain a suitable time switch on the separate circuit for limiting to the controlled heating periods, hereinafter specified, the use of electric service at this rate schedule. The time switch shall remain the property of Public Service and shall be set and controlled exclusively by Public Service;

(a-8) The controlled heating period shall be normally from 11:00 P.M. of one day to 9:30 A.M. of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 115
Original Sheet No. 116

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 117**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for controlled water heating storage or for the electric heating elements of a water heating system connected to an active solar collection system. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$0.63 in each month [$0.67 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

For all use during the controlled storage heating period	
Charge	Charge Including SUT
$ 0.001925	$ 0.002053

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 70 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 118**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

Tax Adjustment Credit:

This mechanism is designed to return the Safe Harbor Adjusted Repair Expense (SHARE) deductions to customers net of any offsets for deferred storm and regulatory costs, IRS adjustments and adjust for any major tax changes, such as tax reform. Interest at the two-year treasury rate plus 60 basis points. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule WHS.

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 119**

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
(Continued)

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Electric service will be furnished under this rate schedule during the controlled storage heating period under the following conditions:

(a-1) Line capacity at location is sufficient to supply water heating service;

(a-2) Customer shall be using service for some purpose other than water heating and water heating service shall be furnished through the same service connection which supplies such other service;

(a-3) Water heating equipment shall be operated at not less than 208 volts;

(a-4) Service for all water heating use will be controlled by a time switch or other control device and registered on a separate meter furnished and installed by Public Service for that purpose;

(a-5) Service is to an automatic storage-type water heater approved by Public Service; if the water heater is equipped with more than one heating element, the thermostats controlling the heating elements shall be interlocked so that only one of such elements can operate at a time;

(a-6) Customer shall install, at its own expense, a separate circuit of approved standard wiring for such water heater including proper connections for the installation of the meter and time switch or other control device;

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 120**

RATE SCHEDULE WHS

WATER HEATING STORAGE SERVICE

(Continued)

(a-7) Where the water heater load does not preclude the use of a Public Service time switch or other control device, Public Service shall furnish, install, regulate and maintain a suitable time switch or other control device to limit the hours of energy available to the water heater. Where the water heater load does preclude the use of a Public Service time switch or other control device, the customer must furnish, install, and maintain a suitable relay, contact or other device which; in response to a Public Service signal, will energize the water heating installation;

(a-8) The controlled storage heating period shall be from 9 P.M. (EST) of one day to 7 A.M. (EST) of the following day. Public Service may change such period depending upon load conditions on its system.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 121
Original Sheet No. 122

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 123**

RATE SCHEDULE HS
BUILDING HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

This rate schedule is closed and is in the process of elimination. Delivery service under this rate schedule is limited to permanently installed comfort building heating equipment in premises that are presently served under this rate schedule. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$3.75 in each month [$4.00 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges per Kilowatt-hour:

In each of the months of October through May		In each of the months of June through September	
Charges	Charges Including SUT	Charges	Charges Including SUT
$ 0.029426	$ 0.031375	$ 0.098011	$ 0.104504

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 124**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charges, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HS.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 125**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

GENERATION CAPACITY AND TRANSMISSION OBLIGATIONS:

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** This rate schedule is available for permanently installed comfort building heating where:

(a-1) Building heating equipment is operated at not less than 208 volts and has a total capacity of not less than five kilowatts;

(a-2) The wiring system metered under this rate schedule utilizes panels, troughs, conduit and wiring completely independent of the general lighting service for the building.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 126**

RATE SCHEDULE HS
BUILDING HEATING SERVICE
(Continued)

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 127
Original Sheet No. 128

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 129**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$4.78 in each month [$5.10 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.7660	$ 4.0155	per kilowatt of Monthly Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.4441	$ 10.0698	per kilowatt of Monthly Peak Demand

Distribution Kilowatt-hour Charges:

In each of the months of October through May		In each of the Months of June through September		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$ 0.007858	$ 0.008379	$ 0.003079	$ 0.003283	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 130**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the option of hourly energy pricing service from either Basic Generation Service-Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 131**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) default service. Customers may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule GLP.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kW, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand shall be determined either by the registration of a demand meter furnished by Public Service or by estimate.

Where a demand meter is installed, the customer's Monthly Peak Demand in any month shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval.

Where no demand meter is installed, the customer's Monthly Peak Demand shall be determined by estimate by dividing the kilowatt-hours by 100 for the applicable billing period.

New Customer: Where a new customer applying for service has an anticipated maximum Monthly Peak Demand of 10 kilowatts or more, that customer's Monthly Peak Demand shall be determined by measurement. If the anticipated maximum Monthly Peak Demand is less than 10 kilowatts, the demand may be determined by estimate or measurement.

Existing Customer: Where an existing customer's Monthly Peak Demand is determined, for billing, by measurement and is 10 kilowatts or greater in any of the preceding 12 months, the customer will continue to have their Monthly Peak Demand determined by measurement and is not eligible for determination by estimate.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 132**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

Where an existing customer's Monthly Peak Demand is determined, for billing, by estimate and their monthly billed kilowatt-hours in any of the preceding 12 months exceeds 1,000 kilowatt-hours, or their Monthly Peak Demand exceeds 10 kilowatts by actual measurement, the customer will be converted to have their Monthly Peak Demand, for billing, determined by measurement. If customer's usage is always less than 1,000 kilowatt-hours per month, the customer may be billed under estimated or measured demand.

Self-Generation Customer: For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: The Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 133**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Service:** Service under this rate schedule will not be supplied where:

(a-1) The customers' Monthly Peak Demand exceeds 150 kilowatts in any month;

(a-2) The customer is presently served under Rate Schedule LPL-secondary and their Monthly Peak Demand has exceeded 100 kilowatts in any of the prior 24 consecutive months;

(a-3) The electrical capacity installed by Public Service exceeds 400 kilowatts.

Customers receiving service on the Building Heating Special Provision in July 2003 are exempt from the above limitation (a-1) and (a-3), where in any of the months of October through May the Monthly Peak Demand may exceed 150 kilowatts.

(b) **Resale:** Service under this rate schedule is not available for resale.

(c) **Police Recall or Fire Alarm System Service:** Unmetered police recall or fire alarm system service will be furnished for signaling lamps, bells, or horns with an individual rating not greater than 100 watts or 1/8-horsepower, as rated by Public Service, at a charge of $0.180 ($0.192 including SUT) per month for each signaling lamp, bell, or horn connected, but the total charge shall in no case be less than $1.80 ($1.92 including SUT) per month. No other energy-using devices shall be connected to the police recall or fire alarm system. The customer shall provide, at its own expense, all necessary equipment and wiring, including the service connection. This Special Provision is only available with electric supply furnished by Public Service.

(d) **Religious Houses of Worship Service:** Where electric supply is provided by Public Service to a customer where the primary use of service is for public religious services and customer applies for and is eligible for such service, the customer's monthly bill will be subject to a credit of $0.0500 ($0.0533 including SUT) per kilowatt-hour but not to exceed $50.00 ($53.31 including SUT) in any billing period.

The customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Public Service, the customer shall furnish satisfactory proof of eligibility for service under this Special Provision.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 134**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(e) **Unmetered Service:** Unmetered service will be supplied, at the discretion of Public Service, where estimates of kilowatts and kilowatt-hours are based upon information supplied by the customer and agreed to by Public Service. Such estimates of demand and usage shall be constant on a monthly basis. ~~Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $ 2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.~~

Unmetered service for automated license plate readers (ALPR) and/or closed-circuit television cameras (CCTV) or similar pole attachments used for body politic-affiliated safety activities may be supplied at the direction of Public Service. Unmetered service to ALPR and CCTV devices shall be based on estimates of kilowatts and kilowatt-hours based upon information supplied by the customer, including any available manufacturer specifications regarding power requirements of these devices. At the discretion of Public Service, the estimates for unmetered service to ALPR or CCTV or similar pole attachment devices may require the assumption that the devices are operate at 100 percent load factor based upon their maximum kilowatt rating.

Customer shall notify Public Service in writing at any time as to changes in conditions or operation of the equipment which may affect estimates of demand or use. Public Service reserves the right to meter any and all such installations where customer does not comply, and customer will no longer be eligible for service under this Special Provision. (See Section 7.1 of the Standard Terms and Conditions.) The customer may be required to furnish and install, at its own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense.

Customers taking service under this Special Provision shall be subject to a monthly Unmetered Service Charge of $2.20 ($2.35 including SUT) in lieu of the Service Charge hereinbefore set forth.

(f) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(f-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(f-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 135**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(f-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(f-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(f-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (f-3) or (f-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(f-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(g) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 136**

RATE SCHEDULE GLP

GENERAL LIGHTING AND POWER SERVICE

(Continued)

(g-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(g-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(g-2a) A monthly facilities charge as set forth in Section 3.5.2. of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall be used for all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(g-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(g-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 137**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(g-4) **Changes in Duplicate Service Capacity**: Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(h) **Night Use:** Where a customer has requested Public Service to install a time of day meter for billing under this Special Provision, the following shall apply:

~~(h-1) A Service Charge of $347.77 ($370.81 including SUT) in lieu of the otherwise applicable Service Charge and a Distribution Kilowatt-hour Charge of $0.007858 ($0.008379 including SUT) for kilowatt-hour usage during the Night Period.~~

(h-1~~2~~) The Summer Demand Charge will be applicable only to the kilowatts of Day Period Monthly Peak Demand during the months of June through September.

(h-2~~3~~) A Term of Service on this Special Provision of two years and thereafter until terminated by five days notice.

(h-3~~4~~) The Day Period shall be considered as the hours of 8 A.M. to 8 P.M. Monday through Friday. All other hours shall be considered the Night Period.

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 138**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(i-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (i-2).

(i-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(i-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(i-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 139**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(i-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(i-6) In the event of an emergency condition which occurs outside the period specified in (i-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(j) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(j-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(j-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 140**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(k) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(k-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(k-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(l) Distribution Demand Charge Rebate: A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.

(l-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.

(l-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (l-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.

(l-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.

(l-4) Both new and existing DCFC Charging Locations are eligible for this rebate.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 141 for Future**

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
(Continued)

(l) ~~**Distribution Demand Charge Rebate:** A customer under this rate schedule whose sole usage is for Direct Current Fast Charging (DCFC) Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.~~

~~(l-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.~~

~~(l-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (l-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.~~

~~(l-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.~~

~~(l-4) Both new and existing DCFC Charging Locations are eligible for this rebate.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 142**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at secondary distribution voltages where the customer's measured peak demand exceeds 150 kilowatts in any month and also at primary distribution voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES (excluding Direct Current Fast Charging [DCFC] customers):

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 3.6224	$ 3.8624	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 8.6179	$ 9.1888	per kilowatt of On-Peak Monthly Peak Demand

~~**Distribution Kilowatt-hour Charges:**~~

~~All Use Charge~~	~~Charge Including SUT~~	
~~$0.000000~~	~~$0.000000~~	~~per kilowatt-hour~~

~~Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.~~

DELIVERY CHARGES FOR SERVICE AT SECONDARY DISTRIBUTION VOLTAGES FOR DCFC CUSTOMERS ONLY:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt-hour Charges:

All Use Charge	Charge Including SUT	
$0.XXXXXX	$X.XXXXXX	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 143**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT PRIMARY DISTRIBUTION VOLTAGES:

Service Charge:

$347.77 in each month [$370.81 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.6885	$ 1.8004	per kilowatt of highest Monthly Peak Demand in any time period

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 9.3731	$ 9.9941	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

	All Use Charge	
Charge	Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 71 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SECONDARY AND PRIMARY DISTRIBUTION VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage for customers who have selected the hourly energy pricing service from either Basic Generation Service - Commercial and Industrial Energy Pricing (BGS-CIEP) or a Third Party Supplier. This charge shall recover costs associated with the administration, maintenance and availability of BGS–CIEP default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 144**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This charge is applicable only to LPL customers for service at secondary distribution voltages. This mechanism provides for recovery of lost revenues associated with various energy efficiency programs. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing. The CIEP Standby Fee shall also be combined with these charges where applicable.

The Distribution Kilowatt Charge and the Conservation Incentive Program Charge shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 145**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Basic Generation Service:

A customer's Peak Load Share (PLS), with adjustments, is the basis for the customer's Generation Obligation. A customer's PLS in effect November 1 of a given year will determine the customer's default service type eligibility effective June 1 of the following year [Basic Generation Service - Residential Small Commercial Pricing (BGS-RSCP) or Basic Generation Service-Commercial and Industrial Pricing (BGS-CIEP)].

Customers that do not receive electric supply from a TPS will be supplied by Public Service through its BGS-RSCP default service for LPL-Secondary customers with a PLS less than 500 kilowatts or BGS-CIEP default service for LPL-Secondary customers with a PLS equal to or greater than 500 kilowatts and LPL-Primary. LPL-Secondary customers with a PLS less than 500 kilowatts may elect BGS-CIEP as their default supply but must notify Public Service of their election of BGS-CIEP as their default supply no later than the second business day in January of each year. Such election shall be effective June 1st of that year and BGS-CIEP will remain as the customer's default supply until they notify Public Service of their election of BGS-RSCP as their default supply no later than the second business day in January and their election of BGS-RSCP shall be effective June 1st of that year.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule LPL for secondary or primary service.

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 6. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers and during any fifteen-minute interval for primary distribution voltage customers. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands, the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen minute intervals.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 146**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any thirty-minute interval for secondary distribution voltage customers, and during any fifteen-minute interval for primary distribution voltage customers, that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month. For self-generation customers served under this standby provision, the Annual Demand Charge will be applied to the customer's Annual Peak Demand in lieu of the Monthly Peak Demand.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 147**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Primary Distribution Alternate Service Charge:** Customers taking service at primary distribution voltage, who were billed the under 100 kilowatt Service Charge in July 2003, and whose Monthly Peak Demand has not exceeded 100 kilowatts in any subsequent month shall be subject to a monthly Service Charge of $21.58 ($23.01 including SUT) in lieu of the otherwise applicable Service Charge.

(b) **Substation Service-Individual Customer:** Where special conditions such as location, size or type of load require that customer be supplied at a subtransmission voltage or at high-voltage as designated in Standard Terms and Conditions, Section 4.2., High Voltage Service, and customer and Public Service agree that Public Service will furnish, install, and maintain a substation solely to serve customer from the secondary side of the transformers at nominal voltages of 4,160 volts, 13,200 volts, or 26,400 volts, such service shall be considered as secondary distribution service. Customer may be required to sell or lease a site for the location of the substation. Public Service may require a guaranteed annual payment and a termination agreement.

This provision is closed and is in the process of elimination and is limited to premises presently served under this provision.

(c) **Resale:** Service under this rate schedule is not available for resale.

(d) **Area Development Service:** Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 148**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 125%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $2.69 ($2.87 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 149**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

(e) **Duplicate Service:** Where, at request of a customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges**: Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 150**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 2.22	$ 2.37	per kilowatt of Duplicate Service Capacity supplied from the same substation as the Normal Service
$ 3.20	$ 3.41	per kilowatt of Duplicate Service Capacity supplied from a different substation than the Normal Service

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 151**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 152**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 153**

RATE SCHEDULE LPL

LARGE POWER AND LIGHTING SERVICE

(Continued)

(h) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(h-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(h-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RS) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 154**

RATE SCHEDULE LPL
LARGE POWER AND LIGHTING SERVICE
(Continued)

(i) ~~**Distribution Demand Charge Rebate:** A customer under this rate schedule, receiving service at secondary voltage levels and whose sole usage is for DCFC Electric Vehicle charging and ancillary energy consumption (communications, area lighting, etc.) and who meets all of the requirements of this special provision, will qualify for a Distribution Demand Charge Rebate. This rebate will remain in effect until the N.J.B.P.U approved $5 million program total has been reached or an electric vehicle specific tariff rate is established in a future rate proceeding.~~

~~(i-1) To qualify for the Demand Charge Rebate, a DCFC customer must agree to provide electric vehicle charging data to PSE&G in accordance with the approved program rules.~~

~~(i-2) Qualifying customers, upon Company approval into the program, will be issued an off bill rebate quarterly that will indicate the corresponding period(s) for which the credit applies, and that will apply to the portion of the approved demand charges set forth in (i-3) below. All rebates are contingent on timely availability of electric vehicle charging data for rebate calculation.~~

~~(i-3) As long as rebate funds are available, the following discounts will apply: For years one and two of the program, the monthly distribution demand charges will be rebated by 75% from the approved rates during the period being calculated. For years three and until new rates become effective following the Company's Next Base Rate Case, monthly distribution demand charges will be rebated by 50% from those in effect during the period being calculated.~~

~~(i-4) Both new and existing DCFC Charging Locations are eligible for this rebate.~~

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 155**

RATE SCHEDULE HTS
HIGH TENSION SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Delivery service for general purposes at subtransmission, transmission and high voltages. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION VOLTAGES:

Service Charge:

$1,911.39 in each month [$2,038.02 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 1.1442	$ 1.2200	per kilowatt of Annual Peak Demand

Summer Demand Charge applicable in the months of June through September:

Charge	Charge Including SUT	
$ 4.1361	$ 4.4101	per kilowatt of On-Peak Monthly Peak Demand

Distribution Kilowatt-hour Charges:

All Use Charge		
Charge	Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT TRANSMISSION VOLTAGES:

Customers historically served under rate schedule HTS-High Voltage currently receiving service at lower voltage levels on facilities under FERC jurisdiction as a result of system modifications mandated by the Company but have not changed their usage characteristics will continue to be billed as High Voltage customers by having their usage adjusted solely by a factor based upon the current Subtransmission and High Voltage Losses as detailed in the Standard Terms and Conditions, Section 4.3. The current adjustment factor for Subtransmission to High Voltage usage is 1.01212%.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 156**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

DELIVERY CHARGES FOR SERVICE AT HIGH VOLTAGE:

Service Charge:

$1,720.25 in each month [$1,834.22 including New Jersey Sales and Use Tax (SUT)].

Distribution Kilowatt Charges:

Annual Demand Charge applicable in all months:

Charge	Charge Including SUT	
$ 0.6322	$ 0.6741	per kilowatt of Annual Peak Demand

Distribution Kilowatt-hour Charges:

	All Use	
Charge	Charge Including SUT	
$0.000000	$0.000000	per kilowatt-hour

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

DELIVERY CHARGES FOR SERVICE AT SUBTRANSMISSION, TRANSMISSION AND HIGH VOLTAGES:

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation costs and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Commercial and Industrial Energy Pricing (CIEP) Standby Fee:

Applicable to all kilowatt-hour usage under this rate schedule. This charge shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default supply service. Refer to the CIEP Standby Fee sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 157**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Kilowatt-hour Charge, the Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Zero Emission Certificate Recovery Charge, the Distribution Adjustment Charge, and the CIEP Standby Fee shall be combined for billing.

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service - Commercial and Industrial Energy Pricing (BGS – CIEP) default service.

The BGS Energy Charges, BGS Capacity Charge, BGS Transmission Charge and BGS Reconciliation Charge are applicable. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule HTS for subtransmission, transmission or high voltage service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 158**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

MINIMUM CHARGE:

Where the use of electricity is for seldom used applications, an Annual Minimum charge may be applied. Such Annual Minimum charge shall equal the diversified connected load of the electric service, in kilowatts, times the Annual Demand Charge times 12. Revenue to satisfy the Annual Minimum requirement shall be derived solely from Distribution Kilowatt Charges and Distribution Kilowatt-hour Charges.

BILLING DETERMINANTS:

Monthly Peak Demand:

The Monthly Peak Demand for each time period shall be determined by the registration of a demand meter furnished by Public Service. The customer's Monthly Peak Demand in any month for each time period shall be the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval. Where the use of electric service is intermittent or subject to violent fluctuations, Public Service may base the customer's Monthly Peak Demand for each time period upon five-minute intervals in lieu of intervals hereinbefore set forth.

Where electric service is supplied for traction power to a rail rapid-transit system, for the purpose of determination of Monthly Peak Demands the hours 8 A.M. to 10 A.M. and 4 P.M. to 7 P.M. shall be included in the Off-Peak time period, and Public Service shall base the customer's Monthly Peak Demand for each time period upon the greatest average number of kilowatts delivered by Public Service during any single coincident hour-ended sixty-minute interval during each time period, in lieu of fifteen-minute intervals. Where traction power is supplied at high voltage (230,000 volts) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining Monthly Peak Demand.

Self-Generation Customer:

For customers with operational self-generation units: 1) with a combined maximum net kilowatt output rating equal to or greater than 50% of their Annual Peak Demand; or, 2) whose premise was served on the former special provision for Standby Service of this rate schedule on July 31, 2003; or 3) who have been granted all necessary air permits by August 1, 2004 for a new or expanded self-generation facility: the On-Peak Monthly Peak Demand used in the determination of the Summer Demand Charges shall be equal to the greatest average number of kilowatts delivered by Public Service during any fifteen-minute interval that occur during the single hour of monthly maximum peak demand of the Public Service distribution system for the applicable summer billing month.

Annual Peak Demand:

The customer's Annual Peak Demand in kilowatts shall be the highest Monthly Peak Demand occurring in any time period of the current month and the preceding 11 months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 159**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the customer's electric supplier from PJM to provide service to the customer.

Generation and Transmission Obligations are used in the determination of the customer's charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 8 A.M. to 10 P.M. Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

The term for delivery service is one year and thereafter until terminated by five days notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Limitations on Loads Served at 138,000 Volts or Higher:** Customer may be required to supply advance information as to conditions affecting its load as an aid to Public Service in load scheduling. Public Service shall not, without prior written acceptance, be obligated to deliver at a single service location an amount of power in excess of a maximum demand of 50,000 kilowatts at 85% power factor.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 160**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(b) **Termination of Service by Customer:** Where a customer, served at 138,000 volts or higher, terminates service prior to fifteen years from the initial date of service, customer shall be obligated to pay Public Service that part of the total actual cost of any of the 138,000 volt or higher facilities, land, easements, interests, or rights of way used in rendering such service, under the following schedules:

(b-1) Actual cost of facilities through the first year; thence such actual cost reduced by 5% quarterly during the next succeeding year; thence reduced by 1-1/4% quarterly during the next succeeding six years; thence reduced by 1-3/4% quarterly during the next succeeding six years; and then reduced by 2% quarterly during the remaining year.

(b-2) Actual cost of land, easements, interest, or rights of way through the first year; thence at 80% of actual cost during any of the next succeeding nine years; thence reduced by 4% quarterly during the remaining five years.

(b-3) In the event that Public Service determines to serve other load from or otherwise use the aforesaid facilities, lands, easements, interests, or rights of way, then their cost shall be allocated on an equitable basis for the determination of the termination payment reflecting the difference between the actual cost and the allocated cost.

(c) **Resale**: Service under this rate schedule is not available for resale.

(d) **Area Development Service**: Where a new or existing customer takes service under this rate schedule at a single service connection located within the municipal boundaries of the cities of Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken, Union City, Plainfield, Gloucester City, Passaic City, Weehawken, Kearny, or Orange, service will be supplied under this provision subject to the following conditions:

(d-1) Each customer will be required to sign an Application for Area Development Service under this rate schedule. Public Service shall define a customer as new or existing for purposes of this application. In the case of existing customers, the base year period twelve Monthly Peak Demands in kilowatts shall be specified by Public Service and agreed to by the customer prior to institution of any credits.

(d-2) Customers shall be eligible for credits under this Special Provision only to the extent that they have signed an Application for Area Development Service and meet the minimum load conditions. For new customers, the minimum load must be no less than 25 kilowatts of the applicable Monthly Peak Demand. For existing customers, the average twelve-month minimum load must be no less than 50 kilowatts of applicable Monthly Peak Demand during the previous twelve months. In addition, during any three consecutive months subsequent to an acceptance of the application by Public Service, existing customer applicable Monthly Peak Demands must be at least 110%, or for customers under the minimum load an addition of at least 50 kilowatts, of applicable Monthly Peak Demands in comparable months of the previous 36 months to qualify for credits. Credits for new and existing customers shall commence in the first month subsequent to such qualification.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 161**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

In no case shall any customer receive credits under this Special Provision who has previously applied for electric service at the same or new location in excess of 300 kilowatts which has been approved for service by Public Service 90 days from the effective date of this Special Provision for the original nine cities and 90 days from the effective date of the modified Special Provision for any additional cities.

(d-3) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply to all kilowatts so measured for new customers. A new customer, for purposes of this Special Provision, shall be defined either as a customer taking service in a new or renovated building or premise, or a customer taking service in an existing building or premise whose activities or use of electric service is substantially different from that of the previous customer. Where no business has been conducted at a building or premise for at least three months, any customer shall be considered a new customer for purposes of this Special Provision.

(d-4) A credit of $1.79 ($1.91 including SUT) per kilowatt of Monthly Peak Demand shall apply only to those kilowatts so measured for existing customers which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first month of qualification. An existing customer, for purposes of this Special Provision, shall be defined as a customer whose activities or use of electric service is substantially the same as that of the previous customer, except that such customer shall be eligible for this Special Provision to the extent that the previous customer was so eligible, and for the remainder of the previous customer's term.

(d-5) Where a customer signs an Application for Area Development Service and elects to be billed under this Special Provision, the term of service shall be seven years in lieu of the term stated in this rate schedule. For new customers, the term shall commence with the first month following qualification and, for existing customers, beginning with the first month following the three-month qualification period. In no case shall the term of service commence prior to the completion of the Application for Area Development Service by the customer and acceptance by Public Service.

Credits under (d-3) or (d-4) will be available to qualifying customers during the first five years of the term. Subsequently, such credits will be reduced by 50% during the final two years of the term.

(d-6) Public Service reserves the right to reject Applications for Area Development Service where the cost of facilities to supply new or existing customers is, in its judgment, excessive or might affect the supply of service to other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 162**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e) **Duplicate Service:** Where, at request of a subtransmission customer, either: a) an additional source or sources of Public Service distribution supply is provided to serve all or part of their load when the principal Public Service distribution source or sources (termed the Normal Service) are unavailable, or b) where such additional sources are supplied as part of standard supply configuration provided by Public Service and such additional source is provided from a different substation or switching station than as determined by Public Service, such service is termed Duplicate Service. Duplicate Service will be furnished only if practical and safe from the standpoint of Public Service and will not be supplied where it would create an unusual hazard or interfere with the provision of service to other customers.

(e-1) **Duplicate Service Capacity:** The maximum electrical requirement, in kilowatts, needed by the customer at any time on the Duplicate Service is defined as Duplicate Service Capacity. The value of the Duplicate Service Capacity will initially be determined by the customer and shall be used by Public Service as the design criteria in construction of the Duplicate Service. The Duplicate Service Capacity shall be reviewed periodically and shall be the greater of the then requested Duplicate Service Capacity, or the highest actual peak demand established in the prior 24 month period on the Duplicate Service or the Normal Service.

(e-2) **Duplicate Service Charges:** Duplicate service charges will be established for each Duplicate Service based on the sum of the following:

(e-2a) A monthly facilities charge as set forth in Section 3.5.2 of these Standard Terms and Conditions calculated as the Facilities Charge Rate times the total costs of any service or line work required to supply Duplicate Service, including extending or reinforcing Public Service distribution facilities and any distribution transformer or metering costs.

Once a facilities charge is established for a facility or premise and there is no material change in the Duplicate Service Capacity to be provided, the basis for the facilities charge shall remain the same as long as the Public Service facilities remain in service and shall apply to all subsequent customers at that facility requesting Duplicate Service, regardless of any lapse in the provision of Duplicate Service to that facility.

(e-2b) Charges for the kilowatts of Duplicate Service Capacity of:

Duplicate Service Capacity Charges		Applicable in all months
Charge	Charge Including SUT	
$ 1.83	$ 1.95	per kilowatt of Duplicate Service Capacity supplied from the same substation or switching station as the Normal Service
$ 2.20	$ 2.35	per kilowatt of Duplicate Service Capacity supplied from a different substation or switching station than the Normal Service

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 163**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(e-3) **Metering and Billing:** Where separate metering is provided, all usage on the duplicate service will be combined for billing purposes with usage on the Normal Service meter.

(e-4) **Changes in Duplicate Service Capacity:** Any material increase in the Duplicate Service Capacity that requires a change in the facilities related to extending Public Service facilities to the customer or the costs of reinforcing related Public Service facilities may require an increase in the monthly facilities charge. Any material decrease in the Duplicate Service Capacity shall not change the monthly facilities charge.

All initial requests or requests for an increase in Duplicate Service Capacity in excess of 5 megawatts shall require the customer to deposit with Public Service the first five year's facilities charges and applicable Duplicate Service Charges on a non-refundable basis prior to the start of any work by Public Service to supply such Duplicate Service. The monthly charges for Duplicate Service shall be applied against the deposited amount in lieu of being billed to the customer until such time as the customer's deposited amount is exhausted, at which time such charges shall be included in the customer's monthly bill. In no event shall any part of the deposit remaining after five years be returned or credited to the customer in any manner.

(f) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available so as to preserve the reliability of the Public Service distribution system. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively, a customer is disqualified for this Special Provision because of continued failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 9.4.2, Metering, for the installed interval metering device if the customer chooses to retain the installed interval meter and the meter is not otherwise required for service. Curtailable Electric Service will be furnished under the following conditions:

(f-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail its load during times of curtailment by the amount stated in the customer's Application/Agreement. A credit of $6.11 ($6.51 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (f-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed solely for this Special Provision.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 164**

RATE SCHEDULE HTS
HIGH TENSION SERVICE
(Continued)

(f-1a) In the event that a customer-specific hourly load curve for customer's normal business operation cannot be developed by Public Service, the curtailed demands will be measured as the difference between the actual hourly load at the time of notification and the actual recorded hourly load for each hour during the curtailment period. Payment will be subject to a maximum equal to the estimated amount of load customer will curtail during curtailments in (f-2).

(f-2) A customer will be required to sign an Application/Agreement for Curtailable Electric Service under this rate schedule. The Application/Agreement will specify the estimated amount of load customer will curtail during curtailments. Curtailment payments will be subject to a maximum of 150% of the estimated amount of load customer will curtail during curtailments. The maximum shall apply subsequent to the customer's first curtailment after election to take service under this Special Provision. The minimum curtailable load is 100 kilowatts. The advanced notification period is a minimum of one hour.

(f-3) This Special Provision will be in effect for the four summer months June through September and apply on weekdays only, excluding holidays, and the potential daily curtailment period shall be the hours between 12:00 Noon and 8:00 P.M. Public Service agrees to limit curtailments, as described in this Special Provision, to a maximum of 120 total hours and a maximum of 15 curtailments during the calendar year.

(f-4) Public Service will contact the customer by telephone or otherwise of the need to curtail load under this Special Provision. The customer shall designate personnel who will accept notification of curtailment on summer weekdays from 9:00 A.M. to 8:00 P.M. Where necessary, Public Service will install and maintain suitable metering at its meter locations for verification of customer compliance with the curtailment and notification agreement.

(f-5) When a customer signs an Application/Agreement for Curtailable Electric Service and elects to be billed under this Special Provision, the term of service will be for two years in lieu of the term stated in this rate schedule, with periodic review of curtailable demand not to exceed twelve months. Public Service reserves the right to determine whether successive terms may be negotiated and under what conditions curtailable demand may be changed.

(f-6) In the event of an emergency condition which occurs outside the period specified in (f-3) above and which threatens the integrity of the Public Service system or the systems to which Public Service is directly or indirectly connected, Public Service may contact customer of the need to curtail load. There will be no penalty for failure to curtail load or meet the agreed upon load reduction. Customers who are able to curtail load will have a credit applied to their bill.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 165**

RATE SCHEDULE HTS

HIGH TENSION SERVICE

(Continued)

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

(h) **Special Provision per Docket No. EO16080788**: This provision of the HTS tariff applies to substation-related service provided to a rail-rapid transit traction power customer that currently subscribes to High Tension Service (HTS) traction power service delivered at 230 kV to an existing multi-substation facility that has been rebuilt by Public Service based upon the approval of the Board of Public Utilities where such approval permits Public Service to own and operate the multi-substation facility and recover the costs of the multi-substation through the traction power customer and distribution rates. In addition, the multi-substation shall provide unique operational characteristics where in disaster or storm events, in which the bulk electric system is inoperable, the multi-substation can operate in isolation to facilitate a microgrid type contingency scheme.

(h-1) The service provided herein shall be the provision of power to a multi- substation facility (meeting the eligibility requirement described herein) owned by Public Service that transforms and delivers power for a traction service HTS customer at voltage levels from 230 kV to 55kV, 27kV, and 12kV. Public Service and the customer will be required to enter into a protocols and operational responsibility agreement that addresses the maintenance and operational responsibilities for the substation. Unless the protocols and operational agreement specifically state otherwise, the terms and conditions of Public Service's tariff shall apply.

(h-2) A customer that is provided this service shall be subject to the requirements of this service tariff as applicable for service delivered at the 230 kV level. All service provided to the substation shall be metered at 230 kV and billed at the 230 kV service rate for traction power service as set forth in the HTS service tariff, except for power delivered to the substation under standard tariff provisions for 13kV which will be billed under the LPL-P tariff.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 166
Original Sheet No. 167
Original Sheet No. 168
Original Sheet No. 169
Original Sheet No. 170
Original Sheet No. 171
Original Sheet No. 172
Original Sheet No. 173
Original Sheet No. 174
Original Sheet No. 175

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 176**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER

APPLICABLE TO:

Electricity produced from a Qualifying Facility as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978, with net capacity no greater than 20 MW and delivered by the Seller to Public Service lines.

RATE:

Service Charge:

$5.00 in each month for installations with a three time period watthour meter, or $30.00 in each month for installations with a recording demand meter.

Energy Payment:

The energy payment in any month for energy received by Public Service shall be based upon the avoided energy cost by time period or by hour, as applicable, in that month (defined as the load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the Public Service Transmission Zone). Historical LMP data may be found on the Pennsylvania-Jersey-Maryland Independent System Operator (PJM) web site at www.pjm.com.

Capacity Payment:

Purchases from a Qualifying Facility that also qualifies as a PJM Installed Capacity Resource, may receive a capacity payment when the capacity exceeds 100 kilowatts and that capacity meets certain reliability criteria as established from time to time by PJM. Capacity payments or charges, if applicable, will be based on the revenue received by Public Service for selling such capacity in the final PJM capacity auction prior to delivery, adjusted for all penalties and other charges assessed to Public Service by PJM related to the non-performance or unavailability of such capacity.

TIME PERIODS:

The On-Peak time period shall be considered as the hours from 7 A.M. to 9 P.M. (EST) Monday through Friday. All other hours shall be considered the Off-Peak time period.

TERMS OF PAYMENT:

For any month payment to the Seller shall be the energy payment plus a capacity payment and/or capacity penalties, if applicable, less the Service Charge. Payment to the Seller shall be within approximately 90 days from the customer's meter reading date.

SPECIAL PROVISIONS:

(a) Seller shall pay all connection charges that are incurred by Public Service in excess of the costs for supplying the Qualifying Facility's maximum expected distribution delivery requirements including the costs of any required studies. Such charges may also include charges assessed by PJM.

(b) Seller's installation shall conform to Public Service specifications for interconnections as outlined in the applicable standards, and such installation is also subject to any applicable PJM requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 177**

PAYMENT SCHEDULE PEP
PURCHASED ELECTRIC POWER
(Continued)

(c) The Seller shall sign an application for Purchased Electric Power.

(d) All Sellers are required to execute an Operations Coordination and Interconnection Agreement with Public Service and comply with all then current PJM generator interconnection and operational standards. Additional information regarding current PJM generator interconnection standards and procedures may be found on the PJM web site at www.pjm.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 178**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 179**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn street lighting and area lighting to a body politic served from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 7.49	$ 7.99
Cobra-Head Cut-Off	50	58	05-0990	8.02	8.55
Post-Top Town & Country	50	58	05-0946, 05-0947	7.35	7.84
Cobra-Head	70	83	05-0927	9.22	9.83
Franklin Park Type V	70	83	05-4054	20.08	21.41
Acorn Decorative	100	117	05-0969	21.13	22.53
Cobra-Head	100	117	05-0940	9.91	10.57
Cobra-Head Cut-Off Type III	100	117	05-0991	15.16	16.16
Deluxe Acorn	100	117	05-0967	19.43	20.72
Franklin Park Type IV	100	117	05-3328	21.87	23.32
Hagerstown Type V	100	130	05-3190	23.06	24.59
New Oxford Black Type III	100	117	05-3260	22.29	23.77
Post-Top Acorn	100	117	05-0963	17.91	19.10
Post-Top Town & Country	100	117	05-0948	11.07	11.80
Post-Top Town & Country	100	117	05-0949	11.67	12.44
Profiler Type III	100	117	05-4593	16.06	17.12
Signature Type V	100	130	05-3210	24.44	26.06
Tear Drop Small Shade B	100	117	05-3338	20.94	22.33
Maplwood Lantern Type III	100	110	05-3300	32.13	34.26
Villager Type III	100	117	05-3373	29.19	31.12
Tear Drop-Small Type III	100	130	05-7097	25.86	27.57
Acorn Decorative	150	177	05-0984	23.25	24.79
Acorn Scroll	150	171	05-0966	25.19	26.86
Architectural Type III	150	190	05-3222	21.56	22.99
Capitol Type V	150	171	05-3202	20.42	21.77
Cobra-Head	150	171	05-0941	10.25	10.93
Cobra-Head Cut-Off Type II	150	171	05-0994	13.91	14.83
Dayform Traditionaire Type III	150	171	05-3415	16.13	17.20
Deluxe Acorn	150	177	05-0968	19.43	20.72
Deluxe Acorn II Type V	150	171	05-3320	17.68	18.85
Edison III Type III	150	177	05-3326	18.80	20.05
Floodlight	150	171	05-0722, 05-0727	13.68	14.59
Franklin Park Type IV	150	171	05-4055	18.91	20.16
Hagerstown Type V	150	190	05-3192, 05-3193	24.65	26.28
Holophane RSL Type V	150	190	05-0931	21.56	22.99
Journal SQ 20" Globe Type V	150	190	05-4050	21.90	23.35
Liberty II Type V	150	171	05-3360	25.91	27.63
Old Boston Lantern Type II	150	171	05-3172	20.67	22.04

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 180**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Luminaires (continued)

High Pressure Sodium (cont'd)	Lamp	Wattage Including	PSE&G Part		Charge Including
Luminaire Type	Wattage	Ballast	Number	Charge	SUT
Post-Top Acorn	150	177	05-0964	$ 18.78	$ 20.02
Post-Top Town & Country	150	171	05-0950	13.76	14.67
Shoe-Box-Small	150	171	05-0971	15.81	16.86
Signature Green Type V	150	171	05-3218	21.93	23.38
Signature Black Type V	150	190	05-3212	25.88	27.59
Trenton Type III	150	190	05-3263	21.58	23.01
Trenton Type V	150	190	05-3268	21.56	22.99
Villager Type III	150	171	05-3176	21.98	23.44
Acorn Scroll	150	171	05-0960	28.34	30.22
Vandal Resistant Type III	150	171	05-3501	14.13	15.07
Cobra-Head	250	300	05-0928	11.83	12.61
Cobra-Head Cut-Off	250	300	05-0993	14.36	15.31
Cobra-Head Vandal Resistant Shield	250	300	05-3502	17.37	18.52
Concourse Type IV	250	300	05-3017	15.13	16.13
Floodlight	250	300	05-0726	16.47	17.56
Shoe-Box-Large	250	300	05-0970	17.54	18.70
Shoe-Box-Small	250	300	05-0973	17.54	18.70
Signature Type V	250	300	05-3379	33.08	35.27
Trenton Type V	250	300	05-3270	18.45	19.67
Cobra-Head	400	450	05-0925	17.77	18.95
Cobra-Head Cut-Off	400	450	05-0929	17.32	18.47
Cobra-Head Type II	400	450	05-0933	17.77	18.95
Expressway Flood	400	450	05-1001	31.00	33.05
Floodlight	400	449	05-0725	21.04	22.43
Floodlight Bronze	400	449	05-0724	21.04	22.43
Shoe-Box-Large	400	470	05-0975	20.07	21.40
Shoe-Box-Small	400	450	05-0979	15.57	16.60
Tear Drop-Large Shade Type III	400	450	05-3336	24.38	26.00
Tear Drop-Large Type III	400	470	05-7096	28.90	30.81
Power Flood	750	839	05-0721	25.49	27.18
Induction					
Cobra-Head Type III	40	40	05-0901	8.89	9.48
Cobra-Head Type III	80	80	05-0902	9.08	9.68
Cobra-Head Type III	150	150	05-0903	12.96	13.82
Cobra-Head Type III	250	260	05-0904	14.50	15.46
Metal Halide					
Hagerstown Green Type V	100	130	05-3196	27.50	29.32
Capitol Black Type V	100	130	05-3206	27.81	29.65
Signature Black Type V	100	130	05-3215	28.27	30.14
Tear Drop – Type V	100	130	05-3281	27.50	29.32
Liberty I Type III	100	130	05-3351	26.57	28.33

(Charges are for illustrative purposes only see Streetlight Appendix)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 181**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Standard Luminaires (continued)

Metal Halide (cont'd)	Lamp	Wattage Including	PSE&G Part		Charge Including
Luminaire Type	Wattage	Ballast	Number	Charge	SUT
Granville Black Type III	100	130	05-6038	$ 25.17	$ 26.84
Granville wR&B Type III	100	130	05-6040	25.56	27.25
Granville Type III	100	130	05-6042	25.72	27.42
Hallbrook – Type III	100	130	05-6056	28.99	30.91
Tear Drop – Type III	100	130	05-7102	27.50	29.32
Villager	150	170	05-8060	30.26	32.26
Contempo – Type II	150	170	05-8062	27.16	28.96
Imperial – Type III	150	170	05-8141	28.71	30.61
Hagerstown	150	170	05-8151	27.86	29.71
Capitol Type V	150	170	05-8162	28.71	30.61
Signature Black Type IV	150	165	05-8173	28.71	30.61
Architectural Type III	150	170	05-8181	26.93	28.71
Trenton Type V	150	170	05-8197	25.15	26.82
Tear Drop – Type III	150	170	05-8198	27.86	29.71
Granville Leaf Black Type III	150	170	05-8215	24.34	25.95
Deluxe Acorn	150	170	05-8224	25.38	27.06
Liberty I Type III	150	170	05-8230	26.93	28.71
Villager Type III	150	170	05-8252	30.26	32.26
Franklin Park Type V	150	170	05-8312	27.86	29.71
Pima	150	150	05-8393	26.93	28.71
Techtra – Type V	150	170	05-8441	30.72	32.76
Tear Drop – Type V	150	170	05-8658	27.86	29.71
New London Type III	150	170	05-8190	29.56	31.52
Contempo – Type V	250	280	05-8064	29.89	31.87
Signature Black Type III	250	275	05-8170	29.82	31.80
Tear Drop – Small	250	300	05-8211	28.96	30.88
Tear Drop – Type III	250	280	05-8622	29.12	31.05
Tear Drop – Type III	250	280	05-8664	31.44	33.52
Tear Drop – Large Type V	250	280	05-8668	31.05	33.11
Newarker – Type V	250	280	05-8680	29.82	31.80
Floodlight	320	350	05-8003	12.49	13.32
Cobra – Head Type III	320	350	05-8018	12.65	13.49
Tear Drop - Large Type III	320	350	05-8063	31.53	33.62
LED					
Floodlight	0	140	05-9900	16.31	17.39
Franklin Park	80	90	05-9999	31.86	33.97
Trenton	85	85	05-9930	28.61	30.51
Contempo – Type II	85	90	05-9940	31.55	33.64
Signature	85	100	05-9960	31.63	33.73
Newarker	85	95	05-9970	31.63	33.73
Franklin Park	86	90	05-9920	37.57	40.06
Tear Drop-Large w/Brim	125	90	05-9950	39.53	42.15
Tear Drop-Large	125	129	05-9951	30.47	32.49
Floodlight	129	141	05-0734	12.32	13.14

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 182**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Specialty Luminaires

All luminaires not listed above as Standard Luminaires, all non-standard installations of Standard Luminaires, and any luminaire where the customer makes a contribution toward the total installed cost are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.554% (1.657% including SUT) for all Cobra-Head, Floodlights and Town and Country luminaires, and 1.171% (1.249% including SUT) for all other luminaire types. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable to Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable to All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 183**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
1,000 Lumens NEMA Head	105	105	00-0052	$ 3.87	$ 4.13
2,500 Lumens NEMA Head	205	205	00-0054	5.81	6.19
4,000 Lumens NEMA Head	327	327	00-0055	6.36	6.78
6,000 Lumens NEMA Head	448	448	00-0056	6.43	6.86
10,000 Lumens NEMA Head	690	690	00-0057	5.88	6.27
15,000 Lumens NEMA Head	860	860	00-0058	8.24	8.79
High Pressure Sodium					
Offset Flood	250	300	05-1000	32.31	34.45
Metal Halide					
Hagerstown Black Type V	100	130	05-3195	25.13	26.79
Capitol Type V	175	210	05-3207	27.84	29.68
Hagerstown Type V	175	210	05-3197	27.97	29.82
Holophane GV Type III	175	210	05-3293	25.58	27.27
Old Boston Lantern Type II	175	210	05-3186	28.99	30.91
Post-Top Acorn	175	210	05-0965	19.39	20.67
Signature Type IV & Type V	175	210	05-3217	29.74	31.71
Signature Arch Green	175	210	05-3219	29.74	31.71
Trenton Type V	175	210	05-3272	23.59	25.15
Vero-Green (No Cage)	175	210	05-3545	25.49	27.18
Cobra-Head Vandal Resistant Shield	250	300	05-3503	23.56	25.12
Signature Type V	250	300	05-3213	30.99	33.04
Trenton Type III	250	300	05-3386	27.20	29.00
Cobra-Head Cut-Off	400	460	05-0930	17.58	18.74
Cobra-Head Type III	400	465	05-0916	17.58	18.74
Floodlight	400	460	05-0728	19.46	20.75
Gray Narrow Beam Floodlight	400	460	05-0729	19.46	20.75
Shoe-Box-Large	400	465	05-0976	20.89	22.27
Floodlight	1000	1080	05-0421	26.73	28.50
Mercury Vapor					
Cobra-Head	100	118	05-0921	5.93	6.32
Post-Top Town & Country	100	118	05-0935	5.93	6.32
Post-Top Town & Country Type IV	100	118	05-0936	5.93	6.32
Cobra-Head	175	210	05-0920	7.53	8.03
Post-Top Town & Country	175	210	05-0937	6.00	6.40
Post-Top Town & Country IV	175	210	05-0938	6.00	6.40
Cobra-Head	250	290	05-0919	9.32	9.94
Cobra-Head	400	432	05-0918	10.03	10.69
Floodlight	400	453	05-0422	14.61	15.58
Cobra-Head	1000	1085	05-0768	13.11	13.98
Floodlight	1000	1075	05-0420	23.10	24.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 184**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006894	$ 0.007351

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 185**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL.

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Classic I Black	10 ft.	04-1292	$ 27.39	$ 29.20
Aluminum	Windsor Black	11.5 ft.	04-1269	28.16	30.02
Aluminum	Classic I Black	12 ft.	04-1280	26.37	28.12
Aluminum	Classic I Green	12 ft.	04-1290	29.35	31.29
Aluminum	Colonial Black	12 ft.	04-1264	20.96	22.34
Aluminum	Colonial Fluted Black	12 ft.	04-4036	22.39	23.88
Aluminum	Heritage Black	12 ft.	04-3499	29.95	31.93
Aluminum	Rockford Harbor Fluted Black	12 ft.	04-6015	30.86	32.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 186**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles – Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Westwood Black	12 ft.	04-3260	$24.34	$25.95
Aluminum	Classic II	12 ft.	04-1285	36.35	38.76
Aluminum	Journal Square	12 ft.	04-4059	40.49	43.17
Aluminum	Colonial Fluted Black	13 ft.	04-4440	25.68	27.38
Aluminum	Classic I Black	14 ft.	04-1281	29.24	31.18
Aluminum	Classic I Green	14 ft.	04-1291	27.00	28.79
Aluminum	Classic II Black	14 ft.	04-1286	27.55	29.38
Aluminum	Colgate I Black	14 ft.	04-1262	26.87	28.65
Aluminum	Colonial Fluted Black	14 ft.	04-1261	20.80	22.17
Aluminum	Colonial Round Black	14 ft.	04-1265	21.78	23.22
Aluminum	Heritage Black	14 ft.	04-3500	30.16	32.16
Aluminum	Montclair Black	14 ft.	04-4085	29.44	31.39
Aluminum	Round Black	14 ft.	04-1284	25.66	27.36
Aluminum	Square Bronze	14 ft.	04-1251	18.57	19.80
Aluminum	Heritage Gray	14 ft.	04-3503	39.30	41.90
Aluminum	Classic I Black	14.5 ft.	04-1282	25.90	27.62
Aluminum	Classic II	15 ft.	04-1287	18.68	19.91
Aluminum	Classic I Black	16 ft.	04-1283	27.60	29.43
Aluminum	Colonial Fluted	16 ft.	04-1272	31.19	33.26
Aluminum	Colonial Fluted	16 ft.	04-4084	29.96	31.94
Aluminum	Contemporary Black	16 ft.	04-4073	33.16	35.36
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Hudson Black	16 ft.	04-4083	37.57	40.06
Aluminum	Square Bronze	16 ft.	04-4006	23.80	25.38
Aluminum	Round	18 ft.	04-4017	31.63	33.73
Aluminum	Square 5 inch	20 ft.	04-1257	22.65	24.15
Aluminum	Tall Decorative	20 ft.	04-4091	41.60	44.36
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	26.08	27.81
Aluminum	Octagon Round	25 ft.	04-0198	55.08	58.73
Aluminum	Decorative Black	25 ft.	04-3262	44.26	47.19
Aluminum	Fluted	30 ft.	04-7098	64.33	68.59
Aluminum	Square Black	30 ft.	04-1254	33.29	35.50
Aluminum	Montclair Black	36 ft.	04-4090	36.84	39.28

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 187**

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
(Continued)

Standard Lighting Poles - Continued

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Square Bronze	30 ft.	04-1250	$ 31.19	$ 33.26
Aluminum	Round	35 ft.	04-1230	27.33	29.14
Cast Aluminum	Colonial Fluted	12 ft.	04-1260	19.94	21.26
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	*8.57	*9.14
Fiberglass	Round Bronze	20 ft.	04-0203	**9.00	**9.60
Fiberglass	Round Bronze	25 ft.	04-0204	19.39	20.67
Laminated Wood	Laminated Wood	30 ft.	04-0225	12.56	13.39
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	14.70	15.67
Pine	Center Bored	30 ft.	04-0350	8.00	8.53
Pine	Round	30 ft.	04-0302	*9.24	*9.85
Pine	Round	35 ft.	04-0304	*10.92	*11.64
Pine	Round Class IV	40 ft.	04-0306	***12.51	***13.34
Pine	Round Class III	45 ft.	04-0308	****13.33	****14.22

***** The charge for indicated poles installed prior to August 1, 2003 is $0.00 ($0.00 including SUT).
****** The charge for indicated poles installed prior to August 1, 2003 is $2.48 ($2.64 including SUT).
******* The charge for indicated poles installed prior to August 1, 2003 is $4.07 ($4.34 including SUT).
******** The charge for indicated poles installed prior to August 1, 2003 is $6.79 ($7.24 including SUT).

Specialty Lighting Poles and Miscellaneous Devices:

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, any pole where the customer makes a contribution toward the total installed cost, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost less any customer contribution (net of tax gross up) times a factor equal to 1.097% (1.170% including SUT). This Capital Recovery Charge shall remain unchanged over the remaining life of the pole. In underground zones the total installed cost excludes the cost of underground conduits, conductors, manholes and handholes, but includes the cost of equivalent overhead conductors.

(2) A Maintenance Charge that varies by item type and is equal to the following:

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 188**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 189**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Five years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs net of any customer contribution.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable whether or not due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement. Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) Underground Construction:

(b-1) Underground construction will be provided at no additional charge in underground zones designated by Public Service for all public street lighting applications and for nonpublic street lighting applications up to 100 feet distant from the public street as measured at right angles to the curb. Where underground construction is desired for all other applications and in other areas, the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes.

(b-2) In a underground zone designated by Public Service, a standard 30 foot aluminum street lighting pole, or credit equivalent, will be provided for each luminaire utilized for public street lighting by a body politic at no charge. The installation of these poles will be provided with a minimum space between poles of 150 feet when measured along the curb line.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 190**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(b-3) In subdivisions subject to the Regulations for Residential Electric Underground Extensions in N.J.A.C. 14:3-8 et seq., there will be no monthly charge to the local municipality for standard street lighting poles utilized for public street lighting that have been included in the charges paid by the developer of the subdivision as determined under tariff section Regulation for Residential Underground Extension.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

Body Politic customers may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Miscellaneous Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 191**

RATE SCHEDULE BPL

BODY POLITIC LIGHTING SERVICE

(Continued)

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 192
Original Sheet No. 193
Original Sheet No. 194

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 195**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

APPLICABLE TO USE OF SERVICE FOR:

This rate class is closed and in the process of elimination. Firm delivery service and maintenance for dusk to dawn street lighting and area lighting to a body politic served from Publicly-Owned Lighting Facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

MAINTENANCE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 1.87	$ 1.99
Cobra-Head Cut-Off Type IV	50	58	05-0990	1.87	1.99
Post-Top Town & Country	50	58	05-0946	1.87	1.99
Cobra-Head	100	117	05-0940	1.87	1.99
Post-Top Town & Country II	100	117	05-0948	1.87	1.99
Post-Top Town & Country IV	100	117	05-0949	1.87	1.99
Cobra-Head	150	171	05-0941	1.87	1.99
Post-Top Acorn	150	171	05-0964	2.61	2.78
Post-Top Town & Country II	150	171	05-0950	1.87	1.99
Shoe-Box-Large Round	150	171	05-0971	2.61	2.78
Shoe-Box-Large Square	150	171	05-0971	2.61	2.78
Cobra-Head	250	300	05-0928	1.87	1.99
Cobra-Head Cut-Off	250	300	05-0993	1.87	1.99
Shoe-Box-Large	250	300	05-0970	2.61	2.78
Shoe-Box-Large Round	250	300	05-0970	2.61	2.78
Shoe-Box-Large Square	250	300	05-0970	2.61	2.78
Cobra-Head Vandal Resistant Shield	250	300	05-3502	1.87	1.99
Cobra-Head	400	450	05-0925	1.87	1.99
Cobra-Head Cut-Off	400	450	05-0929	1.87	1.99
Shoe-Box-Large	400	470	05-0975	2.61	2.78

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 196**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	Equivalent PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	N/A	$ 5.38	$ 5.74
1,000 Lumens NEMA Head	105	105	N/A	5.38	5.74
2,500 Lumens NEMA Head	205	205	N/A	5.38	5.74
4,000 Lumens NEMA Head	327	327	N/A	5.38	5.74
6,000 Lumens NEMA Head	448	448	N/A	5.38	5.74
10,000 Lumens NEMA Head	690	690	N/A	5.38	5.74
Metal Halide					
Acorn	175	210	N/A	4.06	4.33
Floodlight	1000	1080	N/A	6.11	6.51
Mercury Vapor					
Cobra-Head	175	210	N/A	1.08	1.15
Post-Top Town & Country Type IV	175	210	N/A	0.59	0.63
Cobra-Head	250	290	N/A	0.59	0.63
Cobra-Head	400	432	N/A	0.59	0.63

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 197**

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.006931	$ 0.007390

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 198**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:
a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

The BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule BPL-POF.

BILLING DETERMINANTS:

Kilowatt-hours:

The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 199**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

Generation Obligation:

The customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

The customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

One year for all new lamps and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service from Publicly-Owned Facilities:** Service under this Rate Schedule is only available where Public Service has paid no part of the cost of the distribution facilities, lamps, luminaires and all other associated equipment beyond the point of connection to the Public Service distribution system, such point of connection to be designated by Public Service. The complete lighting installation shall meet with the approval of Public Service for operation and maintenance. Public Service will clean refractors or globes, replace lamps, locate cable faults and make minor cable and socket repairs. Replacement of defective cable, painting or otherwise maintaining posts or luminaires or any other associated equipment shall be done only at the expense of the customer. In the event of repeated damage to the equipment, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 200**

RATE SCHEDULE BPL-POF

BODY POLITIC LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES

(Continued)

(b) **Service to Indicating Lamps:** Service to indicating lamps used for marking location of fire and police boxes, fixed warning or obstruction lights, or similar purposes will be provided where all necessary materials and labor for indicating lamp installations is furnished and installed by and at the expense of the customer. Service to indicating lamps will be furnished only if practicable and safe from the standpoint of Public Service.

(c) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(c-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(c-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC

Original Sheet No. 201
Original Sheet No. 202

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 203**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Luminaires, poles and appurtenances, maintenance and firm delivery service for dusk to dawn private street lighting and outdoor area lighting from Company owned lighting facilities. Customers may either purchase electric supply from a Third Party Supplier (TPS) or from Public Service's Basic Generation Service default service as detailed in this rate schedule.

LUMINAIRE CHARGES (Monthly Charge Per Unit):

Standard Luminaires

High Pressure Sodium Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Cobra-Head	50	58	05-0926	$ 8.72	$ 9.30
Cobra-Head Cut-Off	50	58	05-0990	9.34	9.95
Dayform Traditionaire Type III	50	58	05-3410	24.03	25.62
Post-Top Town & Country	50	58	05-0946	8.72	9.30
Post-Top Town & Country Black Type V	50	58	05-0947	8.72	9.30
Cobra-Head	70	83	05-0927	10.76	11.47
Traditional Bollard Type V	70	83	05-3400	23.12	24.65
Capitol Type V	100	130	05-3200	26.92	28.71
Cobra-Head Cut-Off Type III	100	117	05-0991	21.03	22.43
Cobra-Head	100	117	05-0940	12.86	13.71
Dayform Traditionaire Type III	100	117	05-3412	25.73	27.44
Deluxe Acorn	100	117	05-0967	22.55	24.05
Granville Black Type III	100	117	05-6037	27.88	29.73
Post-Top Acorn	100	117	05-0963	20.93	22.31
Post-Top Town & Country	100	117	05-0948	12.98	13.84
Post-Top Town & Country Type IV	100	117	05-0949	13.73	14.64
Profiler Type III	100	117	05-4593	21.69	23.13
Architectural Type III	150	190	05-3222	25.26	26.93
Cobra-Head	150	171	05-0941	13.16	14.03
Dayform Traditionaire Type III	150	171	05-3415	21.99	23.44
Dayform Traditionaire Type V	150	171	05-3317	27.17	28.97
Deluxe Acorn	150	177	05-0968	22.55	24.05
Edison III Type III	150	177	05-3326	26.88	28.66
Floodlight	150	171	05-0722, 05-0727	16.16	17.23
Franklin Park Type IV	150	177	05-4055	27.41	29.22
Old Boston Type V	150	171	05-0995	22.06	23.52
Post-Top Acorn	150	177	05-0964	22.04	23.50
Post-Top Town & Country	150	171	05-0950	16.10	17.16
Richmond Black Type III	150	177	05-4328	27.08	28.87
Shoe-Box-Small	150	171	05-0971	18.58	19.81
Signature Type V	150	171	05-3212	27.99	29.84
Trenton Type III	150	190	05-3263	25.26	26.93
Trenton Type V	150	177	05-3268	23.84	25.42
Hagerstown Type V	150	171	05-3192	33.45	35.67
Swan – Type V	150	177	05-4103	31.33	33.41
Cobra-Head	250	300	05-0928	14.43	15.39
Cobra-Head Cut-Off	250	300	05-0993	17.63	18.80
Floodlight	250	300	05-0723, 05-0726	19.60	20.90

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 204**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Standard Luminaires (continued)

Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	Charge	Charge Including SUT
High Pressure Sodium (cont'd)					
Shoe-Box-Large	250	300	05-0970	$ 20.79	$ 22.17
Shoe-Box-Small	250	300	05-0973	20.79	22.17
Cobra-Head	400	450	05-0925	21.32	22.73
Cobra-Head Cut-Off	400	450	05-0929	20.75	22.13
Concourse Type III	400	450	05-3018	32.77	34.94
Expressway Flood	400	450	05-1001	36.63	39.06
Floodlight	400	449	05-0724,05-0725	26.32	28.06
Galleria Type AS	400	465	05-3111	32.02	34.15
Shoe Box-Large	400	470	05-0975	24.04	25.63
Shoe-Box-Small	400	450	05-0979	23.98	25.57
Power Flood	750	839	05-0721	34.02	36.27
Induction					
Cobra-Head Type III	40	40	05-0901	11.78	12.57
Cobra-Head Type III	80	80	05-0902	13.19	14.06
Cobra-Head Type III	150	150	05-0903	18.06	19.26
Cobra-Head Type III	250	260	05-0904	21.82	23.26
Metal Halide					
Signature Black Type V	100	130	05-3215	35.14	37.47
Classic Bollard	100	130	05-3423	41.08	43.80
Granville Black Type III	100	130	05-6038	31.29	33.36
Franklin Park Type V	150	170	05-8312	34.63	36.92
Hagarstown w/Cutoff	150	190	05-8316	36.18	38.58
Tear Drop - Type III	250	280	05-8664	38.90	41.48
Floodlight	320	350	05-8003	15.45	16.47
Cobra-Head Type III	320	350	05-8018	15.66	16.70
Profiler Type III	320	350	05-8550	28.55	30.44
LED					
Floodlight	0	140	05-9900	20.95	22.34
Floodlight	129	141	05-0734	15.97	17.03
Ecoform – Type III	158	173	05-6033	26.67	28.44

Specialty Luminaires

All luminaires not listed above as Standard Luminaires and all non-standard installations of Standard Luminaires are deemed Specialty Luminaires. The Monthly Charge Per Unit for all Specialty Luminaires is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 2.004% (2.137% including SUT) for all Cobrahead, Floodlights and Town and Country luminaires, and 1.634% (1.742% including SUT) for all other luminaire types. Customers requesting installation of lighting facilities related to construction

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 205**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires. These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the luminaire.

(2) A Maintenance Charge that varies by luminaire type and size and is equal to the following:

(2-a) **Applicable To Cobra Head, Floodlights And Town And Country Luminaires:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 2.67	$ 2.85
Metal Halide	50 watts and 100 watts	3.27	3.49
	175 watts	3.98	4.24
	250 watts	4.07	4.34
	400 watts	3.58	3.82
	1000 watts	6.48	6.91
Mercury Vapor	All wattages	1.53	1.63
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(2-b) **Applicable To All Other Luminaire Types:**

Lamp Type	Lamp Wattage	Charge	Charge Including SUT
High Pressure Sodium	All wattages	$ 3.34	$ 3.56
Metal Halide	50 watts and 100 watts	3.94	4.20
	175 watts	4.64	4.95
	250 watts	4.74	5.05
	400 watts	4.25	4.53
	1000 watts	7.14	7.62
Mercury Vapor	All wattages	2.19	2.34
Induction	All wattages	1.28	1.37
LED	All wattages	1.10	1.17

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 206**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

Closed Luminaires

Luminaire Type	Lamp Wattage	Wattage including Ballast	PSE&G Part Number	Charge	Charge Including SUT
Filament					
600 Lumens NEMA Head	58	58	00-0081	$ 4.42	$ 4.71
1,000 Lumens NEMA Head	105	105	00-0083	4.63	4.94
2,500 Lumens NEMA Head	205	205	00-0084	7.04	7.50
4,000 Lumens NEMA Head	327	327	00-0085	7.87	8.39
6,000 Lumens NEMA Head	448	448	00-0086	8.15	8.69
10,000 Lumens NEMA Head	690	690	00-0087	7.94	8.47
15,000 Lumens NEMA Head	860	860	00-0088	10.93	11.65
High Pressure Sodium					
Offset Flood	250	300	05-1000	36.84	39.28
Metal Halide					
Vandal Resistant Bollard Type V	100	130	05-3409	29.07	30.99
Bishop Crook	175	210	05-0911	36.42	38.83
Hagarstown w/ Cut-Off Type V	175	210	05-4072	37.65	40.15
Hagerstown Type V	175	210	05-3197	32.22	34.35
Manor Lantern Type III	175	210	05-3615	33.39	35.60
Post Top Acorn	175	210	05-0965	22.52	24.01
Signature Type IV & Type V	175	210	05-3217	34.22	36.49
Cobra Head Cut-Off	400	460	05-0930	21.17	22.57
Floodlight	400	460	05-0728	23.37	24.91
Gray Narrow Beam Floodlight	400	460	05-0729	23.37	24.91
Profiler Type III	400	465	05-5025	33.20	35.40
Shoe-Box-Large	400	465	05-0976	24.91	26.56
Floodlight	1000	1080	05-0421	31.89	34.00
Mercury Vapor					
Cobra-Head	100	118	05-0921	6.98	7.44
Post-Top Town & Country	100	118	05-0935	6.98	7.44
Post-Top Town & Country Type IV	100	118	05-0936	6.98	7.44
Cobra-Head	175	210	05-0920	8.99	9.59
Post-Top Town & Country	175	210	05-0937	8.03	8.56
Post-Top Town & Country Type IV	175	210	05-0938	8.03	8.56
Cobra-Head	250	290	05-0919	11.20	11.94
Cobra-Head	400	432	05-0918	12.50	13.33
Floodlight	400	453	05-0422	17.68	18.85
Cobra-Head	1000	1085	05-0768	17.12	18.26
Floodlight	1000	1075	05-0420	28.67	30.57

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 207**

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
(Continued)

DELIVERY CHARGES:

Distribution Charge per Kilowatt-hour:

Charge	Charge Including SUT
$ 0.007355	$ 0.007842

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 72 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Non-utility Generation Charge:

This charge shall recover above market costs associated with non-utility generation and other generation related costs as may be approved by the Board. Refer to the Non-utility Generation Charge sheet of this Tariff for the current charge.

Solar Pilot Recovery Charge:

This charge is designed to recover the revenue requirements associated with the Public Service Solar Pilot Program per the Board Order in Docket No. EO07040278 less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. Refer to the Solar Pilot Recovery Charge sheet of this tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current credit.

Zero Emission Certificate Recovery Charge:

This charge provides for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board"). Refer to the Zero Emission Certificate Recovery Charge sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Distribution Charge, Societal Benefits Charge, Non-utility Generation Charge, the Solar Pilot Recovery Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Zero Emission Certificate Recovery Charge, and the Distribution Adjustment Charge shall be combined for billing.

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 208**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

ELECTRIC SUPPLY CHARGES:

A customer may choose to receive electric supply from either:

a) A TPS as described in Section 14 of this Tariff, or
b) Public Service through its Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

Third Party Supply:

A customer that receives electric supply from a TPS will be charged for electric supply according to any agreement between the customer and the TPS. The customer will not be charged for electric supply by Public Service.

Basic Generation Service:

Customers that do not receive electric supply from a TPS will be supplied under the Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) default service.

For unmetered lighting, the BGS Energy Charge and the BGS Reconciliation Charge, as applicable, will be applied to all kilowatt-hours billed each month. Refer to the Basic Generation Service sheets of this Tariff for the current charges applicable to Rate Schedule PSAL.

For lighting and all other associated equipment in which Public Service has determined metering is required, the electric supply charges will be charged under Rate Schedule General Lighting and Power (GLP). The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 209**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

LIGHTING POLE AND MISCELLANEOUS DEVICE CHARGES (Monthly Charge Per Unit):

Only poles installed, owned and maintained by Public Service as part of the electric distribution system exclusively for the purpose of providing lighting service under Rate Schedules BPL or PSAL are designated as Lighting Poles.

Standard Lighting Poles

Pole Type	Style	Height	PSE&G Part Number	Charge	Charge Including SUT
Aluminum	Windsor Black	11.5 ft.	04-1269	$ 31.26	$ 33.33
Aluminum	Classic I Black	12 ft.	04-1280	31.79	33.90
Aluminum	Classic II	12 ft.	04-1285	30.81	32.85
Aluminum	Colonial Fluted	12 ft.	04-1260	25.18	26.85
Aluminum	Contemporary Black	12 ft.	04-0353	30.77	32.81
Aluminum	Montclair Black	12 ft.	04-1273	34.75	37.05
Aluminum	Wadsworth Black	12 ft.	04-6011	26.35	28.09
Aluminum	Westwood Black	12 ft.	04-3260	24.34	25.95
Aluminum	Classic I Black	14 ft.	04-1281	32.04	34.17
Aluminum	Classic II Black	14 ft.	04-1286	32.73	34.90
Aluminum	Colgate I Black	14 ft.	04-1262	35.55	37.90
Aluminum	Colonial Fluted Black	14 ft.	04-1261	26.29	28.03
Aluminum	Colonial Round Black	14 ft.	04-1265	26.66	28.43
Aluminum	Heritage Black	14 ft.	04-3500	32.72	34.88
Aluminum	Square 5 inch	14 ft.	04-1256	27.35	29.16
Aluminum	Square Bronze	14 ft.	04-1251	22.29	23.77
Aluminum	Wadsworth Black	14 ft.	04-6009	26.78	28.55
Aluminum	Colonial Fluted	16 ft.	04-4084	34.14	36.40
Aluminum	Contemporary Black	16 ft.	04-4073	35.55	37.90
Aluminum	Heritage Black	16 ft.	04-3501	39.53	42.15
Aluminum	Square 5 inch	20 ft.	04-1257	28.66	30.56
Aluminum	Square Bronze	20 ft.	04-1252	24.21	25.82
Aluminum	Round	25 ft.	04-1211	33.68	35.91
Aluminum	Square Bronze	25 ft.	04-1258	33.07	35.26
Aluminum	Square Green 5 inch	25 ft.	04-5025	32.25	34.39
Aluminum	Square Bronze	30 ft.	04-1250	38.96	41.54
Aluminum	Round	35 ft.	04-1230	34.17	36.43
Aluminum	Colonial Fluted	10 ft.	04-1247	19.43	20.72
Aluminum	Classic 1 Black	14.5 ft.	04-1282	35.79	38.16
Fiberglass	Smooth Tapered Black	17 ft.	04-0201	8.57	9.14
Fiberglass	Round Bronze	20 ft.	04-0203	10.67	11.38
Fiberglass	Smooth Tapered Black	20 ft.	04-0205	31.66	33.76
Fiberglass	Round Bronze	25 ft.	04-0204	12.61	13.45
Laminated Wood	Natural	25 ft.	04-0195	13.25	14.13
Laminated Wood	Laminated Wood	30 ft.	04-0225	18.64	19.88
Laminated Wood	Laminated Wood Gray	30 ft.	04-0197	21.76	23.20
Pine	Center Bored	30 ft.	04-0350	17.25	18.40
Pine	Round	30 ft.	04-0302	9.24	9.85
Pine	Round	35 ft.	04-0304	10.92	11.64
Pine	Round Class IV	40 ft.	04-0306	13.96	14.88
Pine	Round Class III	45 ft.	04-0308	16.75	17.86

(Charges are for illustrative purposes only see Streetlight Appendix)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 210**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Specialty Lighting Poles and Miscellaneous Devices

All poles not listed above as Standard Lighting Poles, all non-standard installations of standard lighting poles, and all shrouds, brackets and other miscellaneous devices are deemed Specialty Lighting Poles and Miscellaneous Devices. The Monthly Charge Per Unit for Specialty Lighting Poles and Miscellaneous Devices is equal to the sum of the Capital Recovery Charge and Maintenance Charge set forth as follows:

(1) A Capital Recovery Charge equal to the actual total installed cost times a factor equal to 1.635% (1.743% including SUT). Customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a body politic upon completion of the project may elect to contribute to the total installed cost of Specialty Lighting Poles and Miscellaneous Devices.

These contributions, if made, are to be in accordance with Special Provisions (d) and the Capital Recovery Charge applicable is equal to the actual total installed cost less any customer contribution (net of tax gross up) times the applicable factor indicated herein. This Capital Recovery Charge will remain unchanged over the remaining life of the pole.

(2) A Maintenance Charge that varies by item type and is equal to the following*:

Pole and Device Type	Charge	Charge Including SUT
Pine wood pole	$ 0.50	$ 0.54
Laminated wood pole	0.00	0.00
Aluminum pole	0.00	0.00
Fiberglass pole	0.00	0.00
Shrouds, Brackets & Other Miscellaneous Devices	0.00	0.00

* Maintenance Charges for poles and devices that are not otherwise described in (2) above, shall be determined by the Company on a case by case basis.

BILLING DETERMINANTS FOR UNMETERED LIGHTING:

Kilowatt-hours:

For lighting and all other associated equipment in which demand and usage are constant on a monthly basis, estimates of kilowatts and kilowatt-hours will be utilized. The kilowatt-hour estimate is determined for each lamp by dividing total wattage including ballast by 1,000 and multiplying the result by the monthly burning hours as follows:

January	447	July	281
February	374	August	312
February (leap-year)	387	September	343
March	372	October	397
April	317	November	421
May	292	December	456
June	263		

For lighting and all other associated equipment in which demand and usage are not constant on a monthly basis, the service will be metered and billed under Rate Schedule GLP unless Public Service at its sole discretion determines otherwise.

(Charges are for illustrative purposes only see Streetlight Appendix)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 211**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

Generation Obligation:

For unmetered service, the customer's Generation Obligation, in kilowatts, is determined by Public Service no less frequently than once a year. The Generation Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. The Generation Obligation for customers taking service in a new building or premise, as determined by Public Service, is based upon the load requirements, as estimated by Public Service, of the customer's building or premise. The Generation Obligation represents the generator capacity that PJM requires an electric supplier to have available to provide electric supply to a customer.

Transmission Obligation:

For unmetered service, the customer's Transmission Obligation, in kilowatts, is determined in a similar manner to the Generation Obligation described above. The Transmission Obligation represents the level of transmission network service that must be procured by the Customer's electric supplier from PJM to provide service to the customer.

Costs associated with the Generation and Transmission Obligations are included in the charges for Basic Generation Service and may affect the price offered by a Third Party Supplier.

Allowance for Lamp Outages:

Charges reflect an outage allowance based upon normal and abnormal operating conditions. No further allowance will be made.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 9.12 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 212**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

TERM:

For all Standard Luminaires and Standard Lighting Poles: One year and thereafter until terminated by five days' notice, unless underground construction is utilized, where the term shall be five years and thereafter until terminated by five days' notice.

For all Specialty Luminaires and Specialty Lighting Poles and Miscellaneous Devices and all Underground Lighting Installations: Ten years and thereafter until terminated by five days' notice. Customers shall be required to make a payment for all such lighting facilities removed prior to five years from the installation date equal to the cost of removal less salvage plus 75% of the original installed costs; for facilities removed from the fifth to tenth year after installation such payment shall equal the cost of removal less salvage plus 50% of the original installed costs.

Customers who transfer from third party supply to Basic Generation Service may be subject to additional limitations regarding the term of Basic Generation Service as detailed in Section 14 of the Standard Terms and Conditions of this Tariff.

SPECIAL PROVISIONS:

(a) **Service to Customers:** Public Service will furnish and install the lamp, luminaire, bracket, pole, wiring and associated equipment, make necessary lamp renewals, otherwise maintain the installation, and repair or replace all equipment rendered inoperable due to willful or accidental damage. In the event of repeated damage to its facilities, whether willful or accidental, Public Service reserves the right to discontinue such lighting service or require the customer to be responsible for the continued cost of repair or replacement.

Lighting service will be furnished only if practicable for installation and maintenance, safe from the standpoint of Public Service, and will not be supplied where the introduction of such lighting would create an unusual hazard.

(b) **Underground Construction:** Where underground construction is desired the customer shall pay the cost of such underground construction for all conduits, conductors, manholes and handholes. In designated underground zones, up to 100 feet of underground secondary service facilities as measured at right angles to the curb to the nearest pole utilized for lighting service under this Rate Schedule shall be exempt from this provision and will be provided by Public Service at no charge.

(c) Changes in size, type or location:

(c-1) Customers may be required to make a payment toward the costs of installation, removal, relocation and/or changes in lamp size for conversion from one light source to another when the age of the luminaires to be converted is less than 20 years.

Payment shall be based on the unamortized installed cost plus the removal cost less salvage.

Customers will be required to make a payment based on actual cost of the requested work for the temporary replacement and/or relocation of an existing light to a new location and the subsequent movement of the light back to its old location.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 213**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(c-2) A request to install a new light at the same location within 12 months of the removal of an existing light will be considered a replacement of the existing light. A charge may be assessed for any lamp ordered reconnected or reinstalled when the elapsed time is less than 12 months from the request for disconnect.

(c-3) Public Service reserves the right to limit the number of lamp conversions in any year to no more than 5% of the total lamps served at the end of the previous year.

(d) **Replacement of Obsolete Equipment:** Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers.

(e) **Customer Contributions:** The making of a payment to Public Service shall not give the customer any interest in the facilities, the ownership being vested exclusively in Public Service.

PSAL customers requesting installation of lighting facilities related to construction projects where the customer of record and responsibility for the monthly payments will be transferred to a Body Politic upon completion of the project may elect to contribute to the total installed cost of Specialty Luminaires, Specialty Lighting Poles or Maintenance Devices in addition to that which may be required in accordance with Special Provision (b). Public Service may limit the contribution option between zero and the maximum contribution. Such contribution shall be up to a maximum of:

(e-1) The installed cost less $600.00, grossed up for income tax effects, of any luminaire with an installed cost greater than $1,200.00;

(e-2) The installed cost less $600.00, grossed up for income tax effects, of any pole with an installed cost greater than $1,200.00; or

(e-3) The installed cost, grossed up for income tax effects, of any shroud, bracket or other Miscellaneous Devices.

(f) **Unit Life:** Luminaires, poles and all other associated lighting equipment will be removed when replacement parts are required but no longer generally available. At that time the customer may elect for Public Service to install replacement equipment that will be considered as an installation of new facilities and priced at the then current applicable charges.

(g) **TPS Supply:** Customers who desire to purchase their electric supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for electric supply. This package will be provided to the customer at no charge by Public Service.

(g-1) The customer must contract with a TPS to arrange for deliveries to Public Service of the electric supply. A customer is limited to one TPS for electric supply for each account for which the customer receives delivery service.

(g-2) The customer's TPS is required to notify Public Service of the customer's selection prior to 13 days before the customer's scheduled Public Service meter reading date for deliveries to commence on such scheduled meter reading date, and such selection shall remain in effect for the entire billing month. Customer can change TPSs effective only on the date of the customer's scheduled Public Service meter reading date.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 ELECTRIC **Original Sheet No. 214**

RATE SCHEDULE PSAL

PRIVATE STREET AND AREA LIGHTING SERVICE

(Continued)

(h) **Metered Service:** Usage based charges for lighting and all other associated equipment in which Public Service has determined metering is required will be served under Rate Schedule General Lighting and Power (GLP). Associated luminaire and maintenance charges will continue to be served under this rate schedule. The determination of the need for metering shall be at the sole discretion of Public Service giving due consideration to the particular service factors at issue, as well as, whether demand and usage is not constant on a monthly basis.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P. L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 16 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

BPL Proposed Standard Luminaire Charges

Tariff Status	Light Source	Luminaire Type	Lamp Wattage	Wattage Including Ballast	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
Standard (Open)	LED	Cobra Head	20	22	05-3438	$7.90	**$8.42**
Standard (Open)	LED	Cobra Head	36	39	05-3285	$11.46	**$12.22**
Standard (Open)	LED	Cobra Head	56	62	05-3286	$11.90	**$12.69**
Standard (Open)	LED	Cobra Head	73	81	05-3287	$12.56	**$13.39**
Standard (Open)	LED	Cobra Head	107	118	05-3288	$16.90	**$18.02**
Standard (Open)	LED	Cobra Head	180	199	05-3289	$18.70	**$19.94**
Standard (Open)	LED	Floodlight	85	90	05-4090	$10.66	**$11.37**
Standard (Open)	LED	Floodlight	129	140	05-4091	$11.55	**$12.32**
Standard (Open)	LED	Floodlight	266	292	05-1091	$18.40	**$19.62**
Standard (Open)	LED	Town & Country	12	15	05-0905	$21.69	**$23.13**
Standard (Open)	LED	Town & Country	39	43	05-0906	$21.69	**$23.13**
Standard (Open)	LED	Town & Country	64	71	05-0907	$21.84	**$23.29**
Standard (Open)	LED	Traditionaire	23	27	05-3434	$23.15	**$24.68**
Standard (Open)	LED	Traditionaire	46	51	05-3435	$23.15	**$24.68**
Standard (Open)	LED	Traditionaire	77	85	05-3436	$23.15	**$24.68**
Standard (Open)	LED	Shoebox	100	110	05-3165	$19.44	**$20.72**
Standard (Open)	LED	Shoebox	130	145	05-3166	$20.57	**$21.93**
Standard (Open)	LED	Shoebox	160	180	05-3167	$20.93	**$22.32**
Open	LED	NEMA Head	20	25	05-9952	$9.68	**$10.32**
Open	LED	NEMA Head Cobra	20	30	05-9953	$9.73	**$10.37**
Open	LED	PIMA Black T-5	52	56	05-4098	$33.59	**$35.82**
Open	LED	Roadway With Brim	58	60	05-9990	$7.45	**$7.94**
Open	LED	Tear Drop Black	75	84	05-7200	$34.90	**$37.21**
Open	LED	Trenton	85	85	05-9930	$28.73	**$30.63**
Open	LED	Franklin Park	80	90	05-9999	$31.99	**$34.11**
Open	LED	Contempo - Type II	85	90	05-9940	$31.68	**$33.78**
Open	LED	Franklin Park	86	90	05-9920	$37.73	**$40.23**
Open	LED	Tear Drop-Large w/ Brim	125	90	05-9950	$39.69	**$42.32**
Open	LED	PIMA	80	87	05-4082	$22.17	**$23.64**
Open	LED	Deluxe Acorn Black	85	94	05-4071	$22.26	**$23.73**
Open	LED	Newarker	85	95	05-9970	$31.76	**$33.86**
Open	LED	Signature Black T-3	88	95	05-3211	$34.98	**$37.30**
Open	LED	Signature	85	100	05-9960	$31.76	**$33.86**
Open	LED	Tear Drop-Large	125	129	05-9951	$30.58	**$32.61**
Open	LED	Floodlight	0	141	05-9900	$16.35	**$17.43**
Open	LED	Floodlight	129	141	05-0734	$12.34	**$13.16**
Open	LED	Ecoform Black	158	173	05-6031	$23.54	**$25.10**
Open	LED	Ecoform - Type III	158	173	05-6033	$24.05	**$25.64**
Open	LED	Floodlight	266	292	05-1095	$18.40	**$19.62**
Open	LED	Floodlight	363	400	05-0423	$17.79	**$18.97**
Closed	FLU	Fluorescent	400	510	00-0102	$16.33	**$17.41**
Closed	HPS	Cobra-Head	50	58	05-0926	$9.72	**$10.36**
Closed	HPS	Cobra-Head Cut-Off	50	58	05-0990	$8.24	**$8.79**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$19.98	**$21.30**
Closed	HPS	Post-Top Town & Country Black Type V	50	58	05-0947	$19.98	**$21.30**
Closed	HPS	Cobra-Head	70	83	05-0927	$9.77	**$10.42**
Closed	HPS	Franklin Park Type V	70	83	05-4054	$20.61	**$21.98**
Closed	HPS	Maplwood Lantern Type III	100	110	05-3300	$32.26	**$34.40**
Closed	HPS	Acorn Decorative	100	117	05-0969	$21.20	**$22.60**
Closed	HPS	Cobra-Head	100	117	05-0940	$10.54	**$11.24**
Closed	HPS	Cobra Head Cut-Off Type III	100	117	05-0991	$15.52	**$16.55**
Closed	HPS	Deluxe Acorn	100	117	05-0967	$19.96	**$21.28**
Closed	HPS	Franklin Park Type IV	100	117	05-3328	$21.940	**$23.39**
Closed	HPS	New Oxford Black Type III	100	117	05-3260	$22.37	**$23.85**
Closed	HPS	Post-Top Acorn	100	117	05-0963	$18.27	**$19.48**
Closed	HPS	Post-Top Town & Country	100	117	05-0948	$11.39	**$12.14**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$12.00	**$12.80**
Closed	HPS	Profiler Type III	100	117	05-4593	$16.11	**$17.18**
Closed	HPS	Tear Drop Small Shade B	100	117	05-3338	$21.01	**$22.40**
Closed	HPS	Villager Type III	100	117	05-3373	$29.30	**$31.24**
Closed	HPS	Hagerstown Type V	100	130	05-3190	$23.140	**$24.67**
Closed	HPS	Signature Type V	100	130	05-3210	$24.52	**$26.14**
Closed	HPS	Tear Drop-Small Type III	100	130	05-7097	$25.95	**$27.67**
Closed	HPS	Acorn Scroll	150	171	05-0966	$25.27	**$26.94**

BPL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Capitol Type V	150	171	05-3202	$20.99	**$22.38**
Closed	HPS	Cobra-Head	150	171	05-0941	$11.03	**$11.76**
Closed	HPS	Cobra-Head Cut-Off Type II	150	171	05-0994	$13.93	**$14.85**
Closed	HPS	Dayform Traditionaire Type III	150	171	05-3415	$19.86	**$21.18**
Closed	HPS	Deluxe Acorn II Type V	150	171	05-3320	$18.18	**$19.38**
Closed	HPS	Floodlight	150	171	05-0722	$13.70	**$14.61**
Closed	HPS	Floodlight	150	171	05-0727	$13.70	**$14.61**
Closed	HPS	Franklin Park Type IV	150	171	05-4055	$19.45	**$20.74**
Closed	HPS	Liberty II Type V	150	171	05-3360	$25.99	**$27.71**
Closed	HPS	Old Boston Lantern Type II	150	171	05-3172	$21.25	**$22.66**
Closed	HPS	Post-Top Town & Country	150	171	05-0950	$14.16	**$15.10**
Closed	HPS	Shoe-Box-Small	150	171	05-0971	$16.26	**$17.34**
Closed	HPS	Signature Green Type V	150	171	05-3218	$22.54	**$24.03**
Closed	HPS	Villager Type III	150	171	05-3176	$22.59	**$24.09**
Closed	HPS	Acorn Scroll	150	171	05-0960	$28.43	**$30.31**
Closed	HPS	Vandal Resistant Type III	150	171	05-3501	$14.15	**$15.09**
Closed	HPS	Acorn Decorative	150	177	05-0984	$23.31	**$24.85**
Closed	HPS	Deluxe Acorn	150	177	05-0968	$19.98	**$21.30**
Closed	HPS	Edison III Type III	150	177	05-3326	$18.84	**$20.09**
Closed	HPS	Post-Top Acorn	150	177	05-0964	$18.82	**$20.07**
Closed	HPS	Architectural Type III	150	190	05-3222	$21.61	**$23.04**
Closed	HPS	Hagerstown Type V	150	190	05-3192	$24.72	**$26.36**
Closed	HPS	Hagarstown Type V	150	190	05-3193	$24.72	**$26.36**
Closed	HPS	Holophane RSL Type V	150	190	05-0931	$21.61	**$23.04**
Closed	HPS	Journal SQ 20" Globe Type V	150	190	05-4050	$22.48	**$23.97**
Closed	HPS	Signature Type V	150	190	05-3212	$25.95	**$27.67**
Closed	HPS	Trenton Type III	150	190	05-3263	$21.63	**$23.06**
Closed	HPS	Trenton Type V	150	190	05-3268	$21.61	**$23.04**
Closed	HPS	Cobra-Head	250	300	05-0928	$11.83	**$12.61**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$14.36	**$15.31**
Closed	HPS	Cobra-Head Vandal Resistant Shield	250	300	05-3502	$17.37	**$18.52**
Closed	HPS	Concourse Type IV	250	300	05-3017	$15.61	**$16.64**
Closed	HPS	Floodlight	250	300	05-0726	$16.47	**$17.56**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$19.78	**$21.09**
Closed	HPS	Shoe-Box-Small	250	300	05-0973	$17.54	**$18.70**
Closed	HPS	Signature Type V	250	300	05-3379	$33.16	**$35.36**
Closed	HPS	Trenton Type V	250	300	05-3270	$18.45	**$19.67**
Closed	HPS	Offset Flood	250	300	05-1000	$33.22	**$35.42**
Closed	HPS	Floodlight	400	449	05-0725	$21.04	**$22.43**
Closed	HPS	Floodlight Bronze	400	449	05-0724	$21.04	**$22.43**
Closed	HPS	Cobra-Head	400	450	05-0925	$17.77	**$18.95**
Closed	HPS	Cobra-Head Cut-Off	400	450	05-0929	$17.32	**$18.47**
Closed	HPS	Cobra-Head Type II	400	450	05-0933	$17.77	**$18.95**
Closed	HPS	Expressway Flood	400	450	05-1001	$31.02	**$33.08**
Closed	HPS	Shoe-Box-Small	400	450	05-0979	$16.12	**$17.19**
Closed	HPS	Tear Drop-Large Shade Type III	400	450	05-3336	$25.15	**$26.82**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$20.07	**$21.40**
Closed	HPS	Tear Drop-Large Type III	400	470	05-7096	$28.91	**$30.83**
Closed	HPS	Power Flood	750	839	05-0721	$25.49	**$27.18**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0052	$6.99	**$7.45**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0054	$7.53	**$8.03**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0055	$7.53	**$8.03**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0056	$7.53	**$8.03**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0057	$7.53	**$8.03**
Closed	INC	15,000 Lumens NEMA Head	860	860	00-0058	$8.74	**$9.32**
Closed	IND	Cobra-Head Type III	40	40	05-0901	$10.41	**$11.10**
Closed	IND	Cobra-Head Type III	80	80	05-0902	$11.15	**$11.89**
Closed	IND	Cobra-Head Type III	150	150	05-0903	$12.98	**$13.84**
Closed	IND	Cobra-Head Type III	250	260	05-0904	$14.50	**$15.46**
Closed	MH	Hagerstown Green Type V	100	130	05-3196	$27.60	**$29.43**
Closed	MH	Capitol Black Type V	100	130	05-3206	$27.91	**$29.76**
Closed	MH	Signature Black Type V	100	130	05-3215	$28.37	**$30.25**
Closed	MH	Tear Drop - Type V	100	130	05-3281	$27.60	**$29.43**
Closed	MH	Liberty I Type III	100	130	05-3351	$26.66	**$28.43**
Closed	MH	Granville Black Type III	100	130	05-6038	$25.26	**$26.93**

BPL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	MH	Granville w R&B Type III	100	130	05-6040	$25.65	**$27.35**
Closed	MH	Granville Typre III	100	130	05-6042	$25.81	**$27.52**
Closed	MH	Hallbrook - Type III	100	130	05-6056	$29.10	**$31.03**
Closed	MH	Tear Drop - Type III	100	130	05-7102	$27.60	**$29.43**
Closed	MH	Hagerstown Black Type V	100	130	05-3195	$25.80	**$27.51**
Closed	MH	Pima	150	150	05-8393	$27.02	**$28.81**
Closed	MH	Signature Black Type IV	150	165	05-8173	$28.81	**$30.72**
Closed	MH	Villager	150	170	05-8060	$30.36	**$32.37**
Closed	MH	Contempo - Type II	150	170	05-8062	$27.25	**$29.06**
Closed	MH	Imperial - Type III	150	170	05-8141	$28.80	**$30.71**
Closed	MH	Hagerstown	150	170	05-8151	$27.95	**$29.80**
Closed	MH	Capitol Type V	150	170	05-8162	$28.81	**$30.72**
Closed	MH	Architectural Type III	150	170	05-8181	$27.02	**$28.81**
Closed	MH	Trenton Type V	150	170	05-8197	$25.23	**$26.90**
Closed	MH	Tear Drop - Type III	150	170	05-8198	$27.95	**$29.80**
Closed	MH	Granville Leaf Black Type III	150	170	05-8215	$24.41	**$26.03**
Closed	MH	Deluxe Acorn	150	170	05-8224	$25.46	**$27.15**
Closed	MH	Liberty I Type III	150	170	05-8230	$27.02	**$28.81**
Closed	MH	Villager Type III	150	170	05-8252	$30.36	**$32.37**
Closed	MH	Franklin Park Type V	150	170	05-8312	$27.95	**$29.80**
Closed	MH	Techtra - Type V	150	170	05-8441	$30.83	**$32.87**
Closed	MH	Tear Drop - Type V	150	170	05-8658	$27.95	**$29.80**
Closed	MH	New London Type III	150	170	05-8190	$29.66	**$31.62**
Closed	MH	Capitol Type V	175	210	05-3207	$28.61	**$30.51**
Closed	MH	Hagerstown Type V	175	210	05-3197	$28.74	**$30.64**
Closed	MH	Holophane GV Type III	175	210	05-3293	$26.29	**$28.03**
Closed	MH	Old Boston Lantern Type II	175	210	05-3186	$29.79	**$31.76**
Closed	MH	Post-Top Acorn	175	210	05-0965	$19.95	**$21.27**
Closed	MH	Signature Type IV & Type V	175	210	05-3217	$30.55	**$32.57**
Closed	MH	Signature-Arch Green	175	210	05-3219	$30.55	**$32.57**
Closed	MH	Trenton Type V	175	210	05-3272	$24.25	**$25.86**
Closed	MH	Vero-Green (No Cage)	175	210	05-3545	$26.20	**$27.94**
Closed	MH	Signature Black Type III	250	275	05-8170	$29.89	**$31.87**
Closed	MH	Contempo - Type V	250	280	05-8064	$29.96	**$31.94**
Closed	MH	Tear Drop - Type III	250	280	05-8622	$29.18	**$31.11**
Closed	MH	Tear Drop - Type III	250	280	05-8664	$31.51	**$33.60**
Closed	MH	Tear Drop-Large Type V	250	280	05-8668	$31.12	**$33.18**
Closed	MH	Newarker - Type V	250	280	05-8680	$29.89	**$31.87**
Closed	MH	Tear Drop-Small	250	300	05-8211	$29.06	**$30.99**
Closed	MH	Cobra-Head Vandal Resistant Shield	250	300	05-3503	$24.25	**$25.86**
Closed	MH	Signature Type V	250	300	05-3213	$31.87	**$33.98**
Closed	MH	Trenton Type III	250	300	05-3386	$27.98	**$29.83**
Closed	MH	Floodlight	320	350	05-8003	$12.49	**$13.32**
Closed	MH	Cobra-Head Type III	320	350	05-8018	$13.67	**$14.58**
Closed	MH	Tear Drop-Large Type III	320	350	05-8063	$31.58	**$33.67**
Closed	MH	Cobra-Head Cut-Off	400	460	05-0930	$26.11	**$27.84**
Closed	MH	Floodlight	400	460	05-0728	$20.10	**$21.43**
Closed	MH	Gray Narrow Beam Floodlight	400	460	05-0729	$20.10	**$21.43**
Closed	MH	Cobra-Head Type III	400	465	05-0916	$18.18	**$19.38**
Closed	MH	Shoe-Box-Large	400	465	05-0976	$21.57	**$23.00**
Closed	MH	Floodlight	1000	1080	05-0421	$27.76	**$29.60**
Closed	MV	Cobra-Head	100	118	05-0921	$9.94	**$10.60**
Closed	MV	Post-Top Town & Country	100	118	05-0935	$18.98	**$20.24**
Closed	MV	Post-Top Town & Country Type IV	100	118	05-0936	$18.98	**$20.24**
Closed	MV	Cobra-Head	175	210	05-0920	$9.94	**$10.60**
Closed	MV	Post-Top Town & Country	175	210	05-0937	$16.90	**$18.02**
Closed	MV	Post-Top Town & Country Type IV	175	210	05-0938	$16.90	**$18.02**
Closed	MV	Cobra-Head	250	290	05-0919	$12.18	**$12.99**
Closed	MV	Cobra-Head	400	432	05-0918	$10.43	**$11.12**
Closed	MV	Floodlight	400	453	05-0422	$15.13	**$16.13**
Closed	MV	Floodlight	1000	1075	05-0420	$24.04	**$25.63**
Closed	MV	Cobra-Head	1000	1085	05-0768	$13.81	**$14.72**

BPL-POF Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Cobra-Head	50	58	05-0926	$2.27	**$2.42**
Closed	HPS	Cobra-Head	50	58	05-0990	$2.27	**$2.42**
Closed	HPS	Cobra-Head Cut-Off Type IV	50	58	05-0990	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$2.27	**$2.42**
Closed	HPS	Cobra-Head	100	117	05-0940	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type II	100	117	05-0948	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$2.27	**$2.42**
Closed	HPS	Cobra-Head	150	171	05-0941	$2.27	**$2.42**
Closed	HPS	Cobra-Head	150	171	05-0926	$2.27	**$2.42**
Closed	HPS	Post-Top Town & Country Type II	150	171	05-0950	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large Square	150	171	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large Round	150	171	05-0970	$3.15	**$3.36**
Closed	HPS	Cobra-Head	250	300	05-0928	$2.27	**$2.42**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large Round	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$3.15	**$3.36**
Closed	HPS	Vandal Resistant	250	300	05-3502	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Cobra-Head	400	450	05-0925	$2.27	**$2.42**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$3.15	**$3.36**
Closed	HPS	Shoe-Box-Large	400	450	05-0975	$3.15	**$3.36**
Closed	INC	600 Lumens NEMA Head	58	58	00-0074	$6.44	**$6.87**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0075	$6.44	**$6.87**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0077	$6.44	**$6.87**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0078	$6.44	**$6.87**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0079	$6.44	**$6.87**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0080	$6.44	**$6.87**
Closed	MH	Acorn	175	210	05-0964	$4.85	**$5.17**
Closed	MH	Floodlight	1000	1080	00-0043	$7.31	**$7.79**
Closed	MV	Cobra-Head	175	210	00-0002	$1.43	**$1.52**
Closed	MV	Post-Top Town & Country Type IV	175	210	00-0004	$0.75	**$0.80**
Closed	MV	Cobra-Head	250	290	05-0928	$0.75	**$0.80**
Closed	MV	Cobra-Head	400	432	05-0926	$0.75	**$0.80**

PSAL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Standard (Open)	LED	Cobra Head	20	22	05-3438	$11.13	**$11.87**
Standard (Open)	LED	Cobra Head	36	39	05-3285	$18.99	**$20.25**
Standard (Open)	LED	Cobra Head	56	62	05-3286	$19.05	**$20.31**
Standard (Open)	LED	Cobra Head	73	81	05-3287	$19.90	**$21.22**
Standard (Open)	LED	Cobra Head	107	118	05-3288	$19.90	**$21.22**
Standard (Open)	LED	Cobra Head	180	199	05-3289	$22.23	**$23.70**
Standard (Open)	LED	Floodlight	85	90	05-4090	$14.58	**$15.55**
Standard (Open)	LED	Floodlight	129	140	05-4091	$15.68	**$16.72**
Standard (Open)	LED	Floodlight	266	292	05-1091	$24.03	**$25.62**
Standard (Open)	LED	Town & Country	12	15	05-0905	$28.31	**$30.19**
Standard (Open)	LED	Town & Country	39	43	05-0906	$28.31	**$30.19**
Standard (Open)	LED	Town & Country	64	71	05-0907	$28.50	**$30.39**
Standard (Open)	LED	Traditionaire	23	27	05-3434	$30.13	**$32.13**
Standard (Open)	LED	Traditionaire	46	51	05-3435	$30.13	**$32.13**
Standard (Open)	LED	Traditionaire	77	85	05-3436	$30.13	**$32.13**
Standard (Open)	LED	Shoebox	100	110	05-3165	$25.51	**$27.20**
Standard (Open)	LED	Shoebox	130	145	05-3166	$26.91	**$28.70**
Standard (Open)	LED	Shoebox	160	180	05-3167	$28.01	**$29.87**
Open	LED	Franklin Park	86	90	05-9920	$45.05	**$48.03**
Open	LED	Franklin Park	80	93	05-9999	$45.05	**$48.03**
Open	LED	Signature	85	93	05-9960	$44.86	**$47.83**
Open	LED	Floodlight	85	93	05-0733	$54.10	**$57.68**
Open	LED	Deluxe Acorn Black	85	94	05-4071	$31.70	**$33.80**
Open	LED	HAGERSTOWN Black T-4	87	95	05-8317	$45.05	**$48.03**
Open	LED	Floodlight	0	140	05-9900	$21.01	**$22.40**
Open	LED	Floodlight	129	141	05-0734	$16.00	**$17.06**
Open	LED	Ecoform - Type III	158	173	05-6033	$26.75	**$28.52**
Open	LED	Floodlight	266	292	05-1095	$24.03	**$25.62**
Open	LED	Floodlight	363	400	05-0423	$23.42	**$24.97**
Closed	FLU	Fluorescent	400	510	00-0102	$21.75	**$23.20**
Closed	HPS	Dayform Traditionaire Black Type III	50	58	05-3410	$24.13	**$25.73**
Closed	HPS	Cobra-Head Cut-Off	50	58	05-0990	$9.59	**$10.23**
Closed	HPS	Post-Top Town & Country Black Type V	50	58	05-0947	$28.26	**$30.13**
Closed	HPS	Post-Top Town & Country	50	58	05-0946	$28.26	**$30.13**
Closed	HPS	Cobra-Head	50	58	05-0926	$19.51	**$20.80**
Closed	HPS	Traditional Bollard Type V	70	83	05-3400	$23.21	**$24.75**
Closed	HPS	Cobra-Head	70	83	05-0927	$19.51	**$20.80**
Closed	HPS	Granville Black Type III	100	117	05-6037	$27.98	**$29.83**
Closed	HPS	Profiler Type III	100	117	05-4593	$21.76	**$23.20**
Closed	HPS	Dayform Traditionaire Type III	100	117	05-3412	$25.82	**$27.53**
Closed	HPS	Cobra Head Cut-Off Type III	100	117	05-0991	$21.59	**$23.02**
Closed	HPS	Deluxe Acorn	100	117	05-0967	$23.15	**$24.68**
Closed	HPS	Post-Top Acorn	100	117	05-0963	$21.49	**$22.91**
Closed	HPS	Post-Top Town & Country Type IV	100	117	05-0949	$14.11	**$15.04**
Closed	HPS	Post-Top Town & Country	100	117	05-0948	$13.34	**$14.22**
Closed	HPS	Cobra-Head	100	117	05-0940	$19.51	**$20.80**
Closed	HPS	Capitol Type V	100	130	05-3200	$27.63	**$29.46**
Closed	HPS	Dayform Traditionaire Type III	150	171	05-3415	$28.67	**$30.57**
Closed	HPS	Dayform Traditionaire Type V	150	171	05-3317	$27.65	**$29.48**
Closed	HPS	Signature Type V	150	171	05-3212	$28.75	**$30.65**
Closed	HPS	Hagerstown Type V	150	171	05-3192	$33.94	**$36.19**
Closed	HPS	Old Boston Type V	150	171	05-0995	$22.67	**$24.17**
Closed	HPS	Shoe-Box-Small	150	171	05-0971	$28.81	**$30.72**
Closed	HPS	Post-Top Town & Country	150	171	05-0950	$16.56	**$17.65**
Closed	HPS	Cobra-Head	150	171	05-0941	$19.51	**$20.80**
Closed	HPS	Floodlight	150	171	05-0727	$16.18	**$17.26**
Closed	HPS	Floodlight	150	171	05-0722	$16.62	**$17.72**
Closed	HPS	Richmond Black Type III	150	177	05-4328	$27.81	**$29.66**
Closed	HPS	Swan - Type V	150	177	05-4103	$31.43	**$33.51**

PSAL Proposed Standard Luminaire Charges							
Tariff Status	**Light Source**	**Luminaire Type**	**Lamp Wattage**	**Wattage Including Ballast**	**PSE&G Part Number**	**New Charge (w/o SUT)**	**New Charge (w/SUT)**
Closed	HPS	Franklin Park Type IV	150	177	05-4055	$28.15	**$30.02**
Closed	HPS	Edison III Type III	150	177	05-3326	$26.96	**$28.74**
Closed	HPS	Trenton Type V	150	177	05-3268	$24.49	**$26.11**
Closed	HPS	Deluxe Acorn	150	177	05-0968	$23.17	**$24.70**
Closed	HPS	Post-Top Acorn	150	177	05-0964	$22.65	**$24.15**
Closed	HPS	Trenton Type III	150	190	05-3263	$25.95	**$27.67**
Closed	HPS	Architectural Type III	150	190	05-3222	$25.95	**$27.67**
Closed	HPS	Offset Flood	250	300	05-1000	$37.85	**$40.36**
Closed	HPS	Cobra-Head Cut-Off	250	300	05-0993	$17.63	**$18.80**
Closed	HPS	Shoe-Box-Small	250	300	05-0973	$21.40	**$22.82**
Closed	HPS	Shoe-Box-Large	250	300	05-0970	$28.81	**$30.72**
Closed	HPS	Cobra-Head	250	300	05-0928	$19.51	**$20.80**
Closed	HPS	Floodlight	250	300	05-0726	$19.60	**$20.90**
Closed	HPS	Floodlight	250	300	05-0723	$20.18	**$21.52**
Closed	HPS	Floodlight	400	449	05-0725	$27.12	**$28.91**
Closed	HPS	Floodlight Bronze	400	449	05-0724	$26.32	**$28.06**
Closed	HPS	Concourse Type III	400	450	05-3018	$32.78	**$34.95**
Closed	HPS	Expressway Flood	400	450	05-1001	$36.67	**$39.09**
Closed	HPS	Shoe-Box-Small	400	450	05-0979	$24.72	**$26.36**
Closed	HPS	Cobra-Head Cut-Off	400	450	05-0929	$20.75	**$22.12**
Closed	HPS	Cobra-Head	400	450	05-0925	$21.32	**$22.73**
Closed	HPS	Galleria Type AS	400	465	05-3111	$32.03	**$34.15**
Closed	HPS	Shoe-Box-Large	400	470	05-0975	$24.79	**$26.43**
Closed	HPS	Power Flood	750	839	05-0721	$34.02	**$36.27**
Closed	INC	600 Lumens NEMA Head	58	58	00-0081	$4.55	**$4.85**
Closed	INC	1,000 Lumens NEMA Head	105	105	00-0083	$4.78	**$5.09**
Closed	INC	2,500 Lumens NEMA Head	205	205	00-0084	$7.28	**$7.76**
Closed	INC	4,000 Lumens NEMA Head	327	327	00-0085	$8.17	**$8.71**
Closed	INC	6,000 Lumens NEMA Head	448	448	00-0086	$8.49	**$9.05**
Closed	INC	10,000 Lumens NEMA Head	690	690	00-0087	$8.35	**$8.90**
Closed	INC	15,000 Lumens NEMA Head	860	860	00-0088	$11.47	**$12.23**
Closed	IND	Cobra-Head Type III	40	40	05-0901	$12.09	**$12.89**
Closed	IND	Cobra-Head Type III	80	80	05-0902	$13.54	**$14.44**
Closed	IND	Cobra-Head Type III	150	150	05-0903	$18.10	**$19.30**
Closed	IND	Cobra-Head Type III	250	260	05-0904	$21.84	**$23.29**
Closed	MH	Granville Black Type III	100	130	05-6038	$31.40	**$33.48**
Closed	MH	Classic Bollard	100	130	05-3423	$41.24	**$43.97**
Closed	MH	Vandal Resistant Bollard Type V	100	130	05-3409	$29.84	**$31.81**
Closed	MH	Signature Black Type V	100	130	05-3215	$35.77	**$38.14**
Closed	MH	Franklin Park Type V	150	170	05-8312	$34.75	**$37.05**
Closed	MH	Hagarstown w/ Cutoff	150	190	05-8316	$37.14	**$39.60**
Closed	MH	Hagarstown w/ Cutoff Type V	175	210	05-4072	$38.66	**$41.22**
Closed	MH	Manor Lantern Type III	175	210	05-3615	$34.29	**$36.56**
Closed	MH	Signature Type IV & Type V	175	210	05-3217	$35.14	**$37.47**
Closed	MH	Hagerstown Type V	175	210	05-3197	$33.09	**$35.28**
Closed	MH	Post-Top Acorn	175	210	05-0965	$23.15	**$24.68**
Closed	MH	Bishops Crook	175	210	05-0911	$37.40	**$39.87**
Closed	MH	Tear Drop - Type III	250	280	05-8664	$39.96	**$42.60**
Closed	MH	Profiler Type III	320	350	05-8550	$28.58	**$30.47**
Closed	MH	Cobra-Head Type III	320	350	05-8018	$15.66	**$16.70**
Closed	MH	Floodlight	320	350	05-8003	$15.91	**$16.97**
Closed	MH	Cobra-Head Cut-Off	400	460	05-0930	$27.40	**$29.21**
Closed	MH	Gray Narrow Beam Floodlight	400	460	05-0729	$24.10	**$25.69**
Closed	MH	Floodlight	400	460	05-0728	$24.10	**$25.69**
Closed	MH	Profiler Type III	400	465	05-5025	$34.17	**$36.44**
Closed	MH	Shoe-Box-Large	400	465	05-0976	$25.68	**$27.38**
Closed	MH	Floodlight	1000	1080	05-0421	$33.02	**$35.21**
Closed	MV	Post-Top Town & Country Type IV	100	118	05-0936	$21.90	**$23.35**
Closed	MV	Post-Top Town & Country	100	118	05-0935	$21.90	**$23.35**
Closed	MV	Cobra-Head	100	118	05-0921	$19.38	**$20.66**
Closed	MV	Post-Top Town & Country Type IV	175	210	05-0938	$19.66	**$20.97**
Closed	MV	Post-Top Town & Country	175	210	05-0937	$19.66	**$20.97**
Closed	MV	Cobra-Head	175	210	05-0920	$19.38	**$20.66**
Closed	MV	Cobra-Head	250	290	05-0919	$19.38	**$20.66**
Closed	MV	Cobra-Head	400	432	05-0918	$19.38	**$20.66**
Closed	MV	Floodlight	400	453	05-0422	$18.26	**$19.47**
Closed	MV	Floodlight	1000	1075	05-0420	$29.72	**$31.69**
Closed	MV	Cobra-Head	1000	1085	05-0768	$17.88	**$19.07**

BPL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
ALUM	Classic I Black	10 ft.	04-1292	$28.76	**$30.67**
ALUM	Contemporary Black	10 ft.	04-4079	$38.52	**$41.07**
ALUM	Classic II Black	11 ft.	04-1301	$36.07	**$38.46**
ALUM	Windsor Black	11.5 ft.	04-1269	$29.57	**$31.53**
ALUM	Colonial Black	12 ft.	04-1264	$22.13	**$23.60**
ALUM	Rockford Harbor Fluted Black	12 ft.	04-6015	$32.40	**$34.55**
ALUM	Colonial Fluted Black	12 ft.	04-4036	$23.51	**$25.07**
ALUM	Heritage Black	12 ft.	04-3499	$31.45	**$33.53**
ALUM	Westwood Black	12 ft.	04-3260	$25.56	**$27.25**
ALUM	Classic I Green	12 ft.	04-1290	$30.82	**$32.86**
ALUM	Classic I Black	12 ft.	04-1280	$27.69	**$29.52**
ALUM	Colonial Fluted	12 ft.	04-1260	$22.09	**$23.55**
ALUM	Wadsworth Black	12 ft.	04-6011	$37.93	**$40.44**
ALUM	Contemporary Black	12 ft.	04-4435	$39.23	**$41.83**
ALUM	Montclair Green	12 ft.	04-4096	$37.54	**$40.03**
ALUM	Contemporary Black	12 ft.	04-4078	$39.23	**$41.83**
ALUM	Journal Square	12 ft.	04-4050	$39.23	**$41.83**
ALUM	Colonial Blue	12 ft.	04-4032	$34.32	**$36.59**
ALUM	Charleston Black	12 ft.	04-3302	$40.44	**$43.12**
ALUM	Montclair Black	12 ft.	04-1273	$38.96	**$41.54**
ALUM	Journal Square	12 ft.	04-4059	$42.51	**$45.33**
ALUM	Colonial Fluted Black	13 ft.	04-4440	$26.96	**$28.75**
ALUM	Colonial Round Black	14 ft.	04-1265	$22.87	**$24.39**
ALUM	Montclair Black	14 ft.	04-4085	$30.91	**$32.96**
ALUM	Heritage Black	14 ft.	04-3500	$31.67	**$33.77**
ALUM	Classic I Green	14 ft.	04-1291	$28.35	**$30.23**
ALUM	Classic II Black	14 ft.	04-1286	$28.93	**$30.85**
ALUM	Round Black	14 ft.	04-1284	$26.94	**$28.72**
ALUM	Classic I Black	14 ft.	04-1281	$30.70	**$32.73**
ALUM	Colgate I Black	14 ft.	04-1262	$28.21	**$30.08**
ALUM	Colonial Fluted Black	14 ft.	04-1261	$22.27	**$23.75**
ALUM	Square Bronze	14 ft.	04-1251	$19.50	**$20.79**
ALUM	Heritage Gray	14 ft.	04-3503	$41.27	**$44.00**
ALUM	Contemporary Black	14 ft.	04-4071	$39.58	**$42.20**
ALUM	Journal Square	14 ft.	04-4062	$40.77	**$43.47**
ALUM	Journal Square	14 ft.	04-4055	$39.58	**$42.20**
ALUM	Octagon Black	14 ft.	04-0199	$29.66	**$31.62**
ALUM	Classic I Black	14.5 ft.	04-1282	$27.20	**$29.00**
ALUM	Classic II	15 ft.	04-1287	$21.48	**$22.90**
ALUM	Contemporary Black	15 ft.	04-4072	$39.72	**$42.35**
ALUM	Colonial Fluted	16 ft.	04-4084	$31.46	**$33.54**
ALUM	Hudson Black	16 ft.	04-4083	$39.45	**$42.06**
ALUM	Contemporary Black	16 ft.	04-4073	$34.82	**$37.13**
ALUM	Square Bronze	16 ft.	04-4006	$24.99	**$26.65**
ALUM	Heritage Black	16 ft.	04-3501	$41.51	**$44.26**
ALUM	Classic I Black	16 ft.	04-1283	$28.98	**$30.90**
ALUM	Colonial Fluted	16 ft.	04-1272	$32.75	**$34.92**
ALUM	Classic II	16 ft.	04-1288	$36.49	**$38.91**
ALUM	Round	18 ft.	04-4017	$33.21	**$35.41**
ALUM	Classic II	18 ft.	04-1289	$36.63	**$39.06**
ALUM	Plainfield Black	19 ft.	04-4088	$46.59	**$49.68**
ALUM	Tall Decorative	20 ft.	04-4091	$43.68	**$46.57**
ALUM	Square 5 inch	20 ft.	04-1257	$23.78	**$25.36**
ALUM	Square Bronze	20 ft.	04-1252	$30.57	**$32.60**
ALUM	Decorative Black	25 ft.	04-3262	$46.47	**$49.55**
ALUM	Square Bronze	25 ft.	04-1258	$27.63	**$29.46**
ALUM	Round	25 ft.	04-1211	$35.36	**$37.70**
ALUM	Tall Decorative Black	25 ft.	04-4092	$38.95	**$41.53**
ALUM	Square	25 ft.	04-1276	$43.25	**$46.12**

BPL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)	
ALUM	Octagon Round	25 ft.	04-0198	$57.83	**$61.66**	
ALUM	Square Black	30 ft.	04-1254	$34.95	**$37.27**	
ALUM	Square Bronze	30 ft.	04-1250	$32.75	**$34.92**	
ALUM	Fluted	30 ft.	04-7098	$67.55	**$72.03**	
ALUM	Round	35 ft.	04-1230	$28.70	**$30.60**	
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$9.00	**$9.60**	
FIBERGLASS	Round Bronze	20 ft.	04-0203	$9.45	**$10.08**	
FIBERGLASS	Round Bronze	20 ft.	04-0203	$9.45	**$10.08**	
FIBERGLASS	Round Bronze	25 ft.	04-0204	$20.36	**$21.71**	
FIBERGLASS	Round Bronze	25 ft.	04-0204	$20.36	**$21.71**	
LAM WOOD	Laminated Wood Gray	30 ft.	04-0197	$15.83	**$16.88**	
LAM WOOD	Laminated Wood	30 ft.	04-0225	$14.44	**$15.40**	
PINE	Center Bored	30 ft.	04-0350	$9.20	**$9.81**	
PINE	Round	30 ft.	04-0302	$10.63	**$11.33**	
PINE	Round	35 ft.	04-0304	$12.56	**$13.39**	
PINE	Round Class IV	40 ft.	04-0306	$13.26	**$14.14**	
PINE	Round Class III	45 ft.	04-0308	$14.11	**$15.04**	
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$0.00	**$0.00**	*
FIBERGLASS	Round Bronze	20 ft.	04-0203	$2.64	**$2.81**	*
PINE	Round	30 ft.	04-0302	$0.00	**$0.00**	*
PINE	Round	35 ft.	04-0304	$0.00	**$0.00**	*
PINE	Round Class IV	40 ft.	04-0306	$4.35	**$4.64**	*
PINE	Round Class III	45 ft.	04-0308	$7.25	**$7.73**	*

* The charge for indicated poles installed prior to August 1, 2003

PSAL Proposed Tariff Changes to Standard Pole Charges

Pole Type	Style	Height	PSE&G Part Number	New Charge (w/o SUT)	New Charge (w/SUT)
ALUM	Colonial Fluted	10 ft.	04-1247	$22.34	**$23.82**
ALUM	Classic I Black	10 ft.	04-1292	$35.51	**$37.86**
ALUM	Windsor Black	11.5 ft.	04-1269	$35.95	**$38.33**
ALUM	Classic I Black	12 ft.	04-1280	$36.23	**$38.63**
ALUM	Classic II	12 ft.	04-1285	$35.43	**$37.78**
ALUM	Colonial Fluted	12 ft.	04-1260	$28.96	**$30.88**
ALUM	Contemporary Black	12 ft.	04-0353	$35.39	**$37.73**
ALUM	Montclair Black	12 ft.	04-1273	$39.59	**$42.21**
ALUM	Wadsworth Black	12 ft.	04-6011	$30.30	**$32.31**
ALUM	Westwood Black	12 ft.	04-3260	$27.99	**$29.84**
ALUM	Heritage Black	12 ft.	04-3499	$39.86	**$42.50**
ALUM	Classic I Black	14 ft.	04-1281	$36.51	**$38.93**
ALUM	Classic II Black	14 ft.	04-1286	$37.30	**$39.77**
ALUM	Colgate I Black	14 ft.	04-1262	$40.50	**$43.18**
ALUM	Colonial Fluted Black	14 ft.	04-1261	$30.23	**$32.23**
ALUM	Colonial Round Black	14 ft.	04-1265	$30.66	**$32.69**
ALUM	Heritage Black	14 ft.	04-3500	$37.63	**$40.12**
ALUM	Square 5 inch	14 ft.	04-1256	$31.45	**$33.53**
ALUM	Square Bronze	14 ft.	04-1251	$25.63	**$27.33**
ALUM	Wadsworth Black	14 ft.	04-6009	$30.80	**$32.84**
ALUM	Classic I Black	14.5 ft.	04-1282	$37.58	**$40.07**
ALUM	Colonial Fluted	16 ft.	04-4084	$39.26	**$41.86**
ALUM	Contemporary Black	16 ft.	04-4073	$40.50	**$43.18**
ALUM	Heritage Black	16 ft.	04-3501	$41.51	**$44.26**
ALUM	Classic II	18 ft.	04-1289	$36.63	**$39.06**
ALUM	Square 5 inch	20 ft.	04-1257	$32.96	**$35.14**
ALUM	Square Bronze	20 ft.	04-1252	$27.84	**$29.68**
ALUM	Round	25 ft.	04-1211	$35.61	**$37.97**
ALUM	Square Bronze	25 ft.	04-1258	$38.03	**$40.55**
ALUM	Square Green 5 inch	25 ft.	04-5025	$37.09	**$39.55**
ALUM	Square Bronze	30 ft.	04-1250	$44.39	**$47.33**
ALUM	Round	35 ft.	04-1230	$38.93	**$41.51**
FIBERGLASS	Smooth Tapered Black	17 ft.	04-0201	$9.00	**$9.60**
FIBERGLASS	Round Bronze	20 ft.	04-0203	$11.20	**$11.94**
FIBERGLASS	Smooth Tapered Black	20 ft.	04-0205	$33.24	**$35.44**
FIBERGLASS	Round Bronze	25 ft.	04-0204	$13.24	**$14.12**
LAM WOOD	Natural	25 ft.	04-0195	$15.24	**$16.25**
LAM WOOD	Laminated Wood	30 ft.	04-0225	$21.44	**$22.86**
LAM WOOD	Laminated Wood Gray	30 ft.	04-0197	$24.79	**$26.43**
PINE	Center Bored	30 ft.	04-0350	$19.84	**$21.15**
PINE	Round	30 ft.	04-0302	$10.63	**$11.33**
PINE	Round Class 2	35 ft.	04-0112	$23.75	**$25.32**
PINE	Round	35 ft.	04-0304	$12.56	**$13.39**
PINE	Round Class IV	40 ft.	04-0306	$16.05	**$17.11**
PINE	Round Class III	45 ft.	04-0308	$19.26	**$20.54**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 1**

TARIFF

FOR

GAS SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 3 through 6 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 2**

TABLE OF CONTENTS

Title Page ..... Sheet No. 1
Table of Contents ..... Sheet No. 2
Territory Served ..... Sheet Nos. 3 to 6, inclusive
Standard Terms and Conditions ..... Sheet Nos. 7 to 36, inclusive
Societal Benefits Charge ..... Sheet Nos. 41 and 42
Margin Adjustment Charge ..... Sheet No. 43
Green Programs Recovery Charge ..... Sheet No. 44
Conservation Incentive Program ..... Sheet Nos. 48 to 48C, inclusive
Tax Adjustment Credit ..... Sheet No. 51
Distribution Adjustment Charge ..... Sheet No. 52
Basic Gas Supply Service
- Commodity Charges Applicable to Rate Schedule RSG ..... Sheet No. 54
- Commodity Charges Applicable to Rate Schedules GSG, LVG, SLG and CSG ..... Sheet No. 55
- Commodity Charge Applicable to Rate Schedules TSG-NF and CSG ..... Sheet No. 56
- Commodity Charge Applicable to Rate Schedule CIG ..... Sheet No. 57
- Emergency Sales Service Charge Applicable to Rate Schedules RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG ..... Sheet No. 58

Commodity Charge Applicable to Rate Schedule RSG Off-Peak Use ..... Sheet No. 59
Infrastructure Improvement Program Charges ..... Sheet Nos. 60 and 61

Delivery Rate Schedules as listed below:

	Rate Schedule	Sheet Nos.
Residential Service	RSG	65-69
General Service	GSG	72-77
Large Volume Service	LVG	79-84
Street Lighting Service	SLG	87-90
Firm Transportation Gas Service	TSG-F	93-96
Non-Firm Transportation Gas Service	TSG-NF	99-103
Cogeneration Interruptible Service	CIG	107-111
Contract Service	CSG	112-112F

Third Party Supplier Requirements 114-123

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 3**

TERRITORY SERVED

BERGEN COUNTY

Allendale, Borough of
Alpine, Borough of
Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Closter, Borough of
Cresskill, Borough of
Demarest, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Franklin Lakes, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Harrington Park, Borough of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Mahwah, Township of
Maywood, Borough of
Midland Park, Borough of
Montvale, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Northvale, Borough of
Norwood, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Park Ridge, Borough of
Ramsey, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rockleigh, Borough of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Upper Saddle River, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 4**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
New Hanover, Township of
North Hanover, Township of
Palmyra, Borough of
Pemberton, Borough of
Pemberton, Township of
Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westampton, Township of
Willingboro, Township of
Woodland, Township of
Wrightstown, Borough of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Lawnside, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Tavistock, Borough of
Woodlynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Millburn, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
West Deptford, Township of
Westville, Borough of
Woodbury, City of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of
Union City, City of
Weehawken, Township of
West New York, Town of

HUNTERDON COUNTY

East Amwell, Township of
Readington, Township of
Tewksbury, Township of

MERCER COUNTY

East Windsor, Township of
Ewing, Township of
Hamilton, Township of
Hightstown, Borough of
Lawrence, Township of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Helmetta, Borough of
Highland Park, Borough of
Jamesburg, Borough of
Middlesex, Borough of
Milltown, Borough of
Monroe, Township of
New Brunswick, City of
North Brunswick, Township of
Old Bridge, Township of
Piscataway, Township of
Plainsboro, Township of
Sayreville, Borough of
South Amboy, City of
South Brunswick, Township of
South Plainfield, Borough of
South River, Borough of
Spotswood, Borough of

MONMOUTH COUNTY

Allentown, Borough of
Millstone, Township of
Roosevelt, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Butler, Borough of
Chatham, Borough of
Chatham, Township of
Chester, Borough of
Chester, Township of
Denville, Township of
East Hanover, Township of
Florham Park, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

MORRIS COUNTY (continued)

Hanover, Township of
Harding, Township of
Jefferson, Township of
Kinnelon, Borough of
Long Hill, Township of
Madison, Borough of
Mendham, Borough of
Mendham, Township of
Morris, Township of
Morris Plains, Borough of
Morristown, Town of
Parsippany-Troy Hills, Township of
Pequannock, Township of
Randolph, Township of
Riverdale, Borough of

OCEAN COUNTY

Plumsted, Township of

PASSAIC COUNTY

Bloomingdale, Borough of
Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Pompton Lakes, Borough of
Prospect Park, Borough of
Ringwood, Borough of
Totowa, Borough of
Wanaque, Borough of
Wayne, Township of
West Milford, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bedminster, Township of
Bernards, Township of
Bernardsville, Borough of
Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Far Hills, Borough of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Peapack-Gladstone, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

UNION COUNTY

Berkeley Heights, Township of
New Providence, Borough of
Plainfield, City of
Springfield, Township of
Summit, City of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 7**

STANDARD TERMS AND CONDITIONS - INDEX

		Sheet No.
1.	**General**	**9**
2.	**Obtaining Service**	**9**
	2.1. Application	9
	2.2. Initial Selection of Rate Schedule	9
	2.3. Deposit and Guarantee	10
	2.4. Permits	11
	2.5. Service Connections	11
	2.6. Temporary Service	11
3.	**Charges for Service**	**11**
	3.1. General	11
	3.2. Definitions	11
	3.3. Removal of Public Service Facilities	12
	3.4. Temporary Service	13
	3.5. Provision of Service	13
	3.6. Extensions-General Provisions	14
	3.7. Charges for Extensions	14
	3.8. Charges for Increased Load	17
4.	**Characteristics of Service**	**18**
	4.1. Standard Service Supply	18
	4.2. Heat Measurement and Billing Units	18
	4.3. Standard Pressure	18
5.	**Service Connections**	**18**
	5.1. General	18
	5.2. Change in Location of Existing Service Pipe	18
6.	**Meters and Associated Equipment**	**18**
	6.1. General	18
	6.2. Seals	19
	6.3. Protection of Meter and Service Equipment	19
	6.4. Public Service to Turn on Gas	19
	6.5. Change in Location of Meters and Associated Equipment	19
	6.6. Tampering	19
7.	**Customer's Installation**	**20**
	7.1. General	20
	7.2. Piping	20
	7.3. Gas Equipment and Appliances	20
	7.4. Back Pressure and Suction	20
	7.5. Maintenance of Customer's Installation	21
	7.6. Appliance Adjustments	21
	7.7. Adequacy and Safety of Installation	21
	7.8. Liability for Customer's Installation	21
8.	**Meter Reading and Billing**	**21**
	8.1. Measurement of Gas Used	21
	8.2. Correction for Pressure	22
	8.3. Metering on Customer's Premises	22
	8.4. Testing of Meters	23
	8.5. Metering Options	23
	8.6. Billing Adjustments	24
	8.7. Meter Reading and Billing Period	24
	8.8. Proration of Monthly Charges	24
	8.9. Averaged Bills	24
	8.10. Budget Plan (Equal Payment Plan)	25
	8.11. Billing of Charges in Tariff	25
	8.12. Payment of Bills	25
	8.13. Late Payment Charge	25
	8.14. Returned Check Charge	26
	8.15. Field Collection Charge	26
9.	**Leakage**	**26**
10.	**Access to Customer's Premises**	**26**
11.	**Discontinuance of Service**	**26**
	11.1. By Public Service	26
	11.2. At Customer's Request	28
12.	**Reconnection Charge**	**29**
13.	**Service Limitations**	**29**
	13.1. Continuity of Service	29
	13.2. Emergencies	29
	13.3. Unusual Conditions	29
14.	**Third Party Supplier Service Provisions**	**29**
	14.1. Third Party Supplier Gas Supply	29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

		Sheet No.
	14.2. Enrollment	29
	14.3. Selection or Change of Third Party Supplier	30
	14.4. Return to Public Service Basic Gas Supply Service Default Service	30
	14.5. Emergency Sales Service	31
	14.6. Customer Billing Process	32
	14.7. Third Party Supplier's Termination of Customer's Gas Supply	33
	14.8. Continuity of Service	33
	14.9. Regulatory Requirements	33
	14.10. Delivery Liability	33
	14.11. Delivery Control and Possession	33
15.	**New Jersey Authorized Taxes**	**33**
	15.1. New Jersey Sales and Use Tax	33
	15.2. New Jersey Corporation Business Tax	34
16.	**New Jersey Authorized Exemptions**	**35**
	16.1. Exemptions due to LCAPP Legislation	35
17.	**Termination, Change, or Modification of Provisions of Tariff**	**36**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as part of the Gas Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service", set forth the terms and conditions under which gas service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of gas service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution mains and services located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, P.O. Box 350, Trenton, New Jersey, 08625-0350 or 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. **Application:** An application for service may be made at any of the Customer Service Centers of Public Service in person, or by telephone, by the Company's website at www.pseg.com, or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of gas service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters in accordance with N.J.A.C. 14:3-3.2 (e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of gas to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13 Service Limitations, of these Standard Terms and Conditions.

2.2. **Initial Selection of Rate Schedule:** Public Service will assist in the selection of the available rate schedule which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customers may, upon written notice to Public Service within three months after service has begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 10**

STANDARD TERMS AND CONDITIONS
(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities ("Board"), and shall become effective on January 1 of the following year.

For residential customers, interest payments shall be made at least once during each 12-month period in which a deposit is held. Residential customers shall have the option of a credit to the customer's account or a separate check.

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS
(Continued)

2.4. **Permits**: Public Service, where necessary, will make application for any street opening permits for installing its gas facilities necessary to provide new or upgraded service to a customer and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. **Service Connections:** The customer may be required to make a contribution toward the cost of installing a service connection as set forth in Section 5 of these Standard Terms and Conditions.

2.6. **Temporary Service:** Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to Public Service the cost of the facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the revenue from Service Charges, Distribution Charges and Demand Charges received by Public Service during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

3. CHARGES FOR SERVICE

3.1. **General:** Charges for gas usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for gas usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard and Atypical Conditions, or for an Extension.

3.2. **Definitions:** The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded gas service from Public Service.

b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.

c) N.J.A.C. is the New Jersey Administrative Code.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 12**

STANDARD TERMS AND CONDITIONS
(Continued)

d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus Basic Gas Supply Service charges including SUT, assessed in accordance with this Tariff for Gas Service. For Rate CIG the Basic Gas Supply Service Charges is the Estimated Average Commodity Cost plus Losses and applicable SUT.

e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for gas transmission (non-FERC jurisdictional) and/or distribution, whether located on a public street or right of way, or on private property or private right of way, and includes the pipe, rights of way, land, valves, site restoration, regulators and metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the meter and includes the meter. The new plant and/or facilities installed constituting an Extension must be nominally physically continuous from the beginning to the end of the Extension.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional gas load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. Removal of Public Service Facilities: There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

3.4. **Temporary Service**: Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will not be supplied under Rate Schedule SLG.

3.5. **Provision of Service:** Gas service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon customer's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions:** Underground construction is the standard for all gas mains and services. Metering and regulating facilities are normally located above ground outside of buildings, unless required by Public Service operating conditions in which case they will be located inside.

3.5.2. **Atypical Conditions:** When special facilities are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such special facilities, grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges and Facilities Charges as may be equitable under the circumstances involved where: (1) large or special investment is necessary for the supply of service; (2) capacity required to serve Rate Schedules GSG or LVG customer's weather-sensitive or dual-fueled equipment is out of proportion to the use of gas service for occasional, intermittent, or low load factor purposes, or is for short durations. The assessment of any Minimum Charges will be based upon a minimum use requirement of 850 therms per year for each therm of applicable connected load. To the extent that total annual therm usage is less than 850 therms per therm of connected load, any deficiency will be assessed a Minimum Charge of $0.25 ($0.27 including SUT) per therm.

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the customer to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. The costs will be estimated based upon normal conditions, and may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 15**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.2. Multi-unit Developments: Where application for service is made for gas service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit, requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As each unit is connected, as determined by the setting and activation of the Public Service gas meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 16**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service gas meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 17**

STANDARD TERMS AND CONDITIONS
(Continued)

3.8. Charges for Increased Load: When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2 (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 18**

STANDARD TERMS AND CONDITIONS
(Continued)

4. CHARACTERISTICS OF SERVICE

4.1. **Standard Service Supply:** Public Service may commingle gas supplies from several sources. All gas delivered to any customer may be a mixture of gas manufactured or derived from natural sources, altered to remove impurities and to add desirable constituents. The heat content of delivered gas may vary between 950 and 1,150 Btu per cubic foot. The character of the gas will be of a nature which will allow an atmospheric burner to operate without repeated adjustment.

4.2. **Heat Measurement and Billing Units:** For billing purposes, the customer's gas use in cubic feet will be converted to therms, using the actual weighted average heating value, on a dry basis, of the gas distributed in the second preceding calendar month, where a therm is a unit of heat energy equivalent to 100,000 British thermal units (Btu). Metered usage in cubic feet at standard pressure will be corrected to atmospheric pressure by application of a 1.012 multiplier. Metered usage at higher than standard pressure will be corrected to atmospheric pressure by application of appropriate multipliers.

4.3. **Standard Pressure:** The standard pressure supplied at the meter outlet will be within the range of 4 to 7 inches water column pressure.

5. SERVICE CONNECTIONS

5.1. **General:** The Applicant shall consult Public Service as to the exact point at which the meter set will be located and connection to customer piping will be made before installing interior gas piping or starting any other work dependent upon the location of the service pipe.

Public Service will determine the location of the service pipe depending upon existing facilities in the street and other practical considerations.

Gas service will be supplied to each building or premises through a single service pipe except where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or volume of the customer's requirements, make it desirable to install more than one service pipe.

5.2. **Change in Location of Existing Service Pipe:** Any change requested by the customer in the location of the existing service pipe, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. METERS AND ASSOCIATED EQUIPMENT

6.1. **General**: A single meter will be furnished and installed by Public Service for each separately billed rate schedule under which a customer receives service. Public Service shall be consulted regarding meter locations. Meter installations shall be in conformance

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 19**

STANDARD TERMS AND CONDITIONS
(Continued)

with the standards of the fuel gas subcode of the "Uniform Construction Code" and the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. Where permitted, the meter shall be located outside. If the meter is not located outside solely due to the request of the customer, Public Service reserves the right to install remote metering equipment at the customer's expense. See Section 8.5 of these Standard Terms and Conditions. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

When requested by a customer, remote meter reading equipment may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

Additional meters will be installed only where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or the volume of the customer's requirements, make it desirable to install such additional meters.

6.2. **Seals:** Public Service may seal or lock any meters or enclosures containing meters and associated metering equipment. No person except a duly authorized employee of Public Service shall break or remove a Public Service seal or lock.

6.3. **Protection of Meter and Service Equipment:** Customer shall furnish and maintain a suitable space for the meter and associated equipment. Such space shall be as near as practicable to the point of entrance of the gas service pipe, adequately ventilated, dry (inside installation only) and free from corrosive vapors, not subject to extreme temperatures, readily accessible to duly authorized employees or agents of Public Service and shall otherwise conform to the standards of the fuel gas subcode of the "Uniform Construction Code" and to the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. The gas meter cannot be located behind fences or gates unless no other practical location can be identified. Customer shall not tamper with or remove meters or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or the customer's agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

6.4. **Public Service to Turn on Gas:** No person other than a duly authorized employee or agent of Public Service shall turn gas into any new system of piping or into any old system of piping from which the use of gas had been discontinued.

6.5. **Change in Location of Meters and Associated Equipment:** Any change requested by the customer in the existing location of meters and associated equipment, if approved by Public Service, will be made at the expense of the customer.

6.6. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such gas service under the applicable rate schedule including Basic Gas Supply Service default service, based

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 20**

STANDARD TERMS AND CONDITIONS
(Continued)

upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Gas Supply Service default service but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

7. CUSTOMER'S INSTALLATION

7.1. **General:** No material change in the total input rating, or method of operation of customer's equipment shall be made without previous written notice to Public Service. For the purpose of this paragraph a material change in total input rating is defined as a change of 50,000 Btu per hour input or 10%, whichever is larger. A material change in method of operation is defined as a 50% change in the customer's total annual gas consumption.

7.2. **Piping:** Gas piping installed on the customer's premises must conform to all requirements of municipal or other properly constituted public authorities, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and to the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.3. **Gas Equipment and Appliances:** All gas equipment and appliances shall be certified to applicable U.S. standards by a nationally recognized testing laboratory, and marked with the appropriate certification approval. The manner of installation of all gas equipment and appliances shall be in accordance with all local construction codes, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.4. **Back Pressure and Suction:** When the nature of customer's gas fired equipment, gas compressors or gas piping configuration is such that it may cause back pressure or suction in the piping system, meters or other associated equipment of Public Service, suitable protective devices as defined by the standards of the fuel gas subcode of the "Uniform Construction Code", fittings, valves or check valves shall be furnished, installed and maintained by the customer, subject to the inspection and approval by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 21**

STANDARD TERMS AND CONDITIONS
(Continued)

7.5. Maintenance of Customer's Installation: Customer's entire installation shall be maintained in the condition required by the municipal or other public authorities having jurisdiction and by Public Service.

7.6. Appliance Adjustments: Public Service will make, without additional charge, safety related adjustments to gas burners and certain associated equipment as determined by the Board to be necessary to the functioning of gas appliances in use on customer's premises. Other adjustments or repairs to such appliances may be made, or other services connected with the rendering of gas service may be performed, by Public Service at the customer's expense. Service procedures are detailed in "Servicing Equipment and Facilities on Customers' Premises," issued by Public Service and available on request.

7.7. Adequacy and Safety of Installation: Public Service shall not be required to supply gas service until the customer's installation shall have been approved by the authorities having jurisdiction. Public Service may withhold or discontinue its service whenever such installation or part thereof is deemed by Public Service to be unsafe, inadequate, or unsuitable for receiving service, or to interfere with or impair the continuity or quality of service to the customer or to others.

Public Service will assume no responsibility for the condition of customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or nonrejection, nor in any other way, does Public Service give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the customer.

7.8. Liability for Customer's Installation: Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customers' facilities or the equipment of others on customers' premises or by reason of the characteristics of the service that are in accord with Section 4.1 of these Standard Terms and Conditions. Public Service will not be liable for the use, care or handling of the gas service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customers' facilities.

8. METER READING AND BILLING

8.1. Measurement of Gas Used: Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

Where service through more than one meter is permitted by Public Service as outlined under Section 6.1 of these Standard Terms and Conditions, the cubic-foot use registered by the individual meters will be combined for billing purposes. In all other instances, each meter shall be billed separately.

Bills will be based upon registration of Public Service meters except as otherwise provided for in this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 22**

STANDARD TERMS AND CONDITIONS
(Continued)

8.2. Correction for Pressure: In any case where, pursuant to Section 4.3, Public Service measures the gas delivered to a customer under pressure greater than that exerted by a column of water seven inches in height, the cubic feet of gas registered by the meter or meters of Public Service shall be subject to correction for billing purposes by the application of a proper correction factor.

8.3. Metering on Customer's Premises:

8.3.1. General: The service and supply of gas by Public Service for the use of owners, landlords, tenants, or occupants of newly constructed or renovated residential units will be furnished to them as customers of Public Service through Public Service individual meters, except as noted below in Section 8.3.2.

The service and supply of gas by Public Service to owners, landlords, tenants, or occupants of industrial or commercial buildings or residential premises as noted below in section 8.3.2 may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs, apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying gas service from Public Service be permitted to resell it for a profit.

Where customer installs, or has installed a gas-fired pool heating device, service to such device must be limited to a separate line with a shutoff valve or a separate meter.

8.3.2. Sub-metering: The practice where a primary customer of Public Service or customer of record, through the use of direct metering devices, installed, operated and maintained at such customer's expense, monitors, evaluates, or measures their own gas consumption or the consumption of a tenant for accounting or conservations purposes.

Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Public Service owned meter. Gas sub-meters provide the customer-of-record the means to apportion among the end users the cost of gas service being supplied through the Public Service owned meter.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all gas consuming devices must be metered through a single sub-meter.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 23**

STANDARD TERMS AND CONDITIONS
(Continued)

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The customer shall contact Public Service prior to the installation of any sub-metering device to ascertain that it will not cause operating problems. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

8.4. **Testing of Meters:** At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

8.5. **Metering Options:** The following optional metering services are available to customers and are subject to the following charges as indicated in the following subsections:

8.5.1. **Gas Data Pulses and Remotes:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use, and remote metering equipment at the customer's request. Customers requesting these services are subject to a minimum term of one year:

Description	**Set-Up Charge – Data Pulses**		**Monthly Charge**
	Charges	Charges including SUT	
Residential Meter	$100.00	$ 106.63	$1.00
Large Diaphragm – Retrofit	$ 40.00	$ 42.65	$1.00
Large Diaphragm – Change			
Model 53 It	$100.00	$ 106.63	$2.00
Model 10 It	$130.00	$ 138.61	$2.00
Model 20 It	$130.00	$ 138.61	$2.00
Model 30 It	$340.00	$ 362.53	$3.00
Model 60 It	$650.00	$ 693.06	$3.00
Rotary without Instrument	$450.00	$ 479.81	$2.00
Rotary with Instrument	$100.00	$ 106.63	$2.00
Turbine	$100.00	$ 106.63	$2.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 24**

STANDARD TERMS AND CONDITIONS
(Continued)

8.5.2. Customer Usage Information: Where Public Service has an interval meter installed, twelve months of interval usage, where available, will be provided upon request of the customer. The historical interval data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.

Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical usage data on a next-day basis for those customers who request such service. The charges for this service shall include a set up charge of $107.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.

8.6. Billing Adjustments: Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RSG, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments shall be made in accordance with N.J.A.C. 14:3-4.6.

8.7. Meter Reading and Billing Period: All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

8.8. Proration of Monthly Charges: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts and Rate Schedules CIG, TSG-F, TSG-NF, and CSG, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts the minimum period for billing purposes shall be one month.

8.9. Averaged Bills: Where Public Service is unable to read the meter, Public Service may estimate the amount of gas supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in Accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue gas service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 25**

STANDARD TERMS AND CONDITIONS
(Continued)

8.10. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RSG and GSG (where GSG gas service is used for residential purposes in buildings of four or fewer units), shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve month period will be averaged over twelve months and may be paid in twelve equal monthly installments. Adjustments will be made in the twelfth month if actual charges are more or less than the budget amounts billed. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

8.11. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of gas service subsequent to the scheduled meter reading date for the immediately preceding month.

8.12. Payment of Bills: At least 15 days' time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow the customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

8.13. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedule RSG. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 26**

STANDARD TERMS AND CONDITIONS
(Continued)

and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by Public Service from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

8.14. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

8.15. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules: GSG, LVG, SLG, CIG, TSG-F, TSG-NF and CSG.

8.16. Customer's Responsibility to Cooperate with the Company: The charge provisions for extensions are predicated upon cooperation by the Customer in an effort to keep the Company's cost as low as possible. Additional costs resulting from the Customer's failure to cooperate, such as the paving of roads, parking areas or driveways prior to the installation of Company's facilities, shall be borne by the Customer.

9. LEAKAGE

Customer shall immediately give notice to Public Service at its office of any escape of gas in or about the customer's premises. If a leakage is suspected, immediately exit the building and move at least 350 feet away. Once the customer is at a safe distance, call PSE&G Emergency Service Line at 1-800-880-PSEG (7734) or 911 to report a potential gas leak. Customer will not be charged for reporting a potential gas leak.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized governmental officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) nonpayment of a valid bill due for service furnished at a present or previous location, however, nonpayment for business service shall not be a reason for discontinuance of residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 8.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 27**

STANDARD TERMS AND CONDITIONS
(Continued)

Public Service shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for nonpayment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $200.00; and/or 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for nonpayment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 8.12 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of nonpayment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for nonpayment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. and 4:00 P.M. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or on a holiday, absent such emergency.

Subject to the conditions set forth below, discontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. Discontinuance shall be prohibited for a period of 90 days initially when a customer submits a licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provision of N.J.A.C. 14:3-7.7.

1. The Board may extend the 90-day period for good cause upon the receipt of a written request from the customer. The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for nonpayment prior to submission of the licensed medical professional's statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 28**

STANDARD TERMS AND CONDITIONS
(Continued)

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are end-users, service will not be discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP), or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 29**

STANDARD TERMS AND CONDITIONS
(Continued)

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for non-payment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

13.2. Emergencies: Public Service may curtail or interrupt service to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of gas service it will supply or transport and may refuse such service to new customers, to existing customers for additional load, or to customers whose service agreements have expired if Public Service is or will be unable to obtain or does not have assured the necessary production raw materials, equipment and facilities to supply such gas or transportation service. In the case of transportation service, if Public Service, at its sole discretion, determines that such service would not be consistent with the best interest of its customers served under all rate schedules contained herein such service may be denied to applicants for such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Gas Supply: Customers served on Rate Schedules RSG, GSG, LVG, SLG, TSG-NF, and CSG may choose to receive gas supply from either a Third Party Supplier (TPS) or from Public Service through its Basic Gas Supply Service. Customers on these rate schedules who are not enrolled with a TPS will receive their gas supply from Public Service. Customers served on Rate Schedule TSG-F may only receive gas supply from a TPS. The customer's supply of gas is limited to one TPS for the account(s) at a particular customer facility or complex.

A TPS is either a retail energy provider that has been licensed by the Board or is a customer served under Rate Schedules TSG-NF and CSG that has elected to self supply and act as a TPS on their own behalf. All TPSs must execute an Application for Service, be accepted by Public Service, and conform with the Third Party Supplier Requirements section of this Tariff.

14.2. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding gas supply describes the process necessary for a customer to obtain a TPS for gas supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center. Once the customer has chosen a TPS, the customer must provide appropriate authorization as required by their designated supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 30**

STANDARD TERMS AND CONDITIONS
(Continued)

14.3. Selection or Change of Third Party Supplier: In order to be eligible to receive gas supply from a TPS, the customer must contract with a TPS to obtain gas supply for delivery to the customer by Public Service. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of gas supply on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month for Rate Schedules RSG, GSG, LVG, and SLG. Notification for customers on Rate Schedules TSG-F, TSG-NF, and CSG is required prior to the last business day of the month. Such selection shall remain in effect for the entire billing period.

For customers on Rate Schedule RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG, once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer, which will be sent within one business day. In the event of a dispute, assignment of a customer will not occur unless and until the dispute is resolved. This confirmation letter will include notification of the RSG customer's right to rescind their contract with their designated TPS which must be exercised within seven (7) days of mailing of the letter of confirmation. Once assignment has occurred, the TPS will be required to supply all of the gas supply on the Public Service customer's account.

14.4. Return to Public Service Basic Gas Supply Service Default Service: Customers may return to Public Service Basic Gas Supply Service default service for commodity supply under the conditions and procedures as outlined below.

14.4.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: Customers that subsequently choose to return to Basic Gas Supply Service default service must notify Public Service on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day. This confirmation letter will include notification of the customer's right to rescind their selection which must be exercised within seven (7) days of mailing of the letter of confirmation. GSG, LVG, and SLG customers not exercising their right of rescission within the seven (7) day period may be subject to renewable one-year terms on Basic Gas Supply Service default service.

If a customer's TPS notifies Public Service on or before the 10th calendar day of the month that it has terminated its supply relationship with the customer, such termination will become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 31**

STANDARD TERMS AND CONDITIONS
(Continued)

14.4.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): For customers that subsequently choose to return to Basic Gas Supply Service default service, the return will become effective on the first of the month following the customer's written notification to Public Service, provided that such notice was given prior to the last business day of the preceding month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day.

If a customer's TPS notifies Public Service that it has terminated its supply relationship with the customer, such termination will become effective on the first of the month after such notification, provided such notification was received no later than the next to last business day of the month. In the event that notification is received after the next to last business day of the month, such termination shall become effective the first of the second month following such notification. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3.

14.4.3. Customers on Rate Schedule TSG-F: Basic Gas Supply Service default service is not available for customers on Rate Schedule TSG-F.

14.5. Emergency Sales Service: Under certain conditions as specified below, Public Service may supply gas commodity on the Emergency Sales Service provision. Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

14.5.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, until the customer's next meter reading date the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its applicable Daily Contract Quantity (DCQ) therms. Thereafter, the customer will be placed on the applicable Public Service Basic Gas Supply Service default service. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

14.5.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, for the balance of the current month the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its therm usage. Commencing on the first of the following month the customer will be placed on the applicable Public Service Basic Gas Supply Service default service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 32**

STANDARD TERMS AND CONDITIONS
(Continued)

14.5.3. Customers on Rate Schedule TSG-F: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that the customer will be billed, in addition to all applicable delivery charges the Emergency Sales Service Charge for all of its therm usage.

14.6. Customer Billing Process: For TPS retail customers served under Rate Schedule RSG, GSG, LVG and SLG, Public Service will provide one combined bill containing both Public Service charges and TPS gas supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for third party supplied services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for third party supplied services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.6.1. Payment of Bills: Where Public Service provides billing service, the payment of bills, including TPS's charges for gas supply if billed by Public Service, will be made to Public Service and will be in accordance with Section 8, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

14.6.2. Late Payment Charges: A late payment charge in accordance with Section 8.13, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for gas supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for gas supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.6.3. Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges and all undisputed TPS charges for gas supply if such charges are billed by Public Service in accordance with Section 8, Meter Reading and Billing, and Section 14.6.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customer and TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 33**

STANDARD TERMS AND CONDITIONS
(Continued)

14.7. Third Party Supplier's Termination of Customer's Gas Supply: A TPS will not be permitted to physically connect or disconnect gas supply service to a customer.

14.8. Continuity of Service: Public Service shall have the right: (i) to require a TPS's gas supply sources to be disconnected from Public Service's gas system; (ii) to otherwise curtail, interrupt, or reduce a TPS's gas supply; or (iii) to disconnect a TPS's customer(s) in accordance with Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions.

14.9. Regulatory Requirements: Public Service will not be responsible for: making any arrangements necessary; obtaining from appropriate regulatory bodies any approvals necessary; any costs, charges and expenses including but not limited to the payment to appropriate governmental entities for any tax or assessment relative to the acquisition, transportation or use of customer's gas supply.

14.10. Delivery Liability: Public Service will not be liable in any way for any failure in whole or in part, temporary or permanent, to deliver gas under this Tariff for Gas Service to the extent such failure is due to customer's TPS's failure to deliver gas supplies to Public Service in accordance with the TPS Requirements. Public Service will not be liable in any way for errors in the calculation of the customer's DCQ and/or delivery requirement.

14.11. Delivery Control and Possession: After customer delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

15. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P.L. 2006, c. 44, as amended by P.L. 2009, c. 240 and P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Gas Service.

15.1. New Jersey Sales and Use Tax: In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

15.1.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b-1) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 34**

STANDARD TERMS AND CONDITIONS
(Continued)

b-2) Cogeneration facilities that are constructed after January 1, 2010.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Agencies or instrumentalities of the federal government.

e) International organizations of which the United States of America is a member.

f) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57.

15.1.2. Exemptions due to the Business Retention and Relocation Assistance Act: The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c. 303 (C.52:27H-60 *et seq.*) and P.L.1966, c. 30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

15.2. New Jersey Corporation Business Tax: In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 35**

STANDARD TERMS AND CONDITIONS

(Continued)

15.2.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the above tariff charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

16. NEW JERSEY AUTHORIZED EXEMPTIONS

The following exemptions are authorized by the State of New Jersey and are applied in accordance with P.L. 2011, c.9 (the "Long Term Capacity Agreement Pilot Program", "LCAPP Legislation"). The exemptions take effect January 28, 2011.

16.1. Exemptions due to LCAPP Legislation: Electric generators who use natural gas to generate electricity that is sold for resale will be exempt from a societal benefits charge pursuant to N.J.S.A. 48:3-60.1 or any other charge designed to recover the costs for social, energy efficiency, conservation, environmental or renewable energy on natural gas delivery service or commodity that is used to generate electricity that is sold for resale. This exemption includes the Societal Benefits Charge (SBC) and the Green Programs Recovery Charge (GPRC). Each customer's exemption will be effective upon completion of an Annual Certification form.

a) The Annual Certification form shall be a prerequisite for the exemption and shall be furnished to customers of record in December and returned to Public Service by the customer no later than January 15th of each year. The Annual Certification form shall certify the percentage of gas used at their New Jersey generation facilities during the immediately preceding calendar year to generate electricity that was sold for resale. This Certification will serve as the percentage of the customers' throughput that will be exempt from the SBC and the GPRC. This Certification will then be used for the succeeding annual period commencing in February. If the customer fails to return the form, then the SBC and the GPRC will be assessed on all of the customer's usage until a completed Annual Certification form is received to be effective after the next subsequent meter reading. If the customer returns a completed Annual Certification Form on or before January 15, then adjustments to customer's bills to reflect changes in the percentage of gas used to generate electricity for resale will be made on a prospective basis beginning in February.

b) In those cases where prior calendar year usage is not available, the customer will submit an Annual Certification form with an estimated percentage of gas that will be used at their New Jersey generation facilities for the current calendar year to generate electricity to be sold for resale. Once agreement has been reached with PSE&G regarding the estimated percentage, the completed Certification will serve as the percentage of the customers' throughput that will be exempt from the SBC and the GPRC effective after the next subsequent meter reading on a prospective basis for the remainder of the current calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 36**

STANDARD TERMS AND CONDITIONS
(Continued)

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 37
Original Sheet No. 38
Original Sheet No. 39
Original Sheet No. 40

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 41**

SOCIETAL BENEFITS CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Social Programs	$ 0.000000
Energy Efficiency and Renewables Programs	0.019520
Manufactured Gas Plant Remediation	0.008753
Universal Service Fund - Permanent	0.010800
Universal Service Fund - Lifeline	0.005800
Societal Benefits Charge	$ 0.044873
Societal Benefits Charge including New Jersey Sales and Use Tax (SUT)	$ 0.047846

Societal Benefits Charge

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under-over recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Ninth Revised Sheet No. 41 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 42**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This factor shall recover costs associated with existing social programs.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 43**

MARGIN ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG, TSG-F
(Per Therm)

Margin Adjustment Charge ..... ($0.005821)

Margin Adjustment Charge including New Jersey Sales and Use Tax (SUT)..... ($0.006207)

Margin Adjustment Charge

This mechanism is designed to insure return of certain net revenues to the customer classes denoted above. Actual net revenues will be subject to deferred accounting. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 43 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 44**

GREEN PROGRAMS RECOVERY CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Carbon Abatement Program	($0.000470)
Energy Efficiency Economic Stimulus Program	0.000167
Energy Efficiency Economic Extension Program	0.000329
Energy Efficiency Economic Extension Program II	0.000472
Energy Efficiency 2017 Program	0.003000
Clean Energy Future – Energy Efficiency Program	0.005528
Green Programs Recovery Charge	$0.009026

Green Programs Recovery Charge including New Jersey Sales and Use Tax SUT $0.009624

Green Programs Recovery Charge

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rate shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 44 filed with the BPU on October 1, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG
(Per Therm)

	Conservation Incentive Program	Conservation Incentive Program including SUT
RSG	$0.060736	$0.064760
GSG	$0.044451	$0.047396
LVG	$0.004748	$0.005063

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed usage per customer during the preceding annual period. The Conservation Incentive Mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company's books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Usage Per Customer
– the Actual Usage per Customer ("AUC") shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the ANC for the corresponding month.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

6. Baseline Usage per Customer
– the Baseline Usage per Customer ("BUC") shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

The BUC shall be reset each time new base rates are placed into effect through a base rate case.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 48 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups. The Customer Class Groups shall be as follows:

Group I: RSG
Group II: GSG
Group III: LVG

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Margin Revenue Factor
– the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I (RSG): $0.437483
Group II (GSG): $0.328242
Group III (LVG): $0.046383

The MRF shall be reset each time new base rates are placed into effect, including Infrastructure Investment Program ("IIP") or all other future base rate changes.

10. Degree Days (DD)
– the difference between 65^{o}F and the mean daily temperature for the day. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day.

11. Actual Calendar Month Degree Days
– the accumulation of the actual Degree Days for each day of a calendar month.

12. Normal Calendar Month Degree Days
– the level of calendar month degree days to which the weather portion of the CIP applies.

The normal calendar month Degree Days will be the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station at the Newark airport and will be updated annually. The base level of normal HDD for the defined winter period months for the 2023-2024 Winter Period are set forth in the table below:

Month	Normal Heating Degree Days
October 2023	225.14
November 2023	515.50
December 2023	810.29
January 2024	1,005.68
February 2024	868.22
March 2024	682.63
April 2024	355.17
May 2024	123.16

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

14. Degree Day Consumption Factors
– the use per degree day component of the gas sales equations by month used in forecasting firm gas sales for the applicable rate schedules. Degree day Consumption Factors for the 2023-2024 Winter Period are set forth below and presented as therms per degree day:

	RSG-Residential		Commercial			Industrial		
Month			GSG		LVG	GSG		LVG
	Heating	Non- Heating	Heating	Non- Heating		Heating	Non- Heating	
Oct.-23	183,348	-	-	-	88,624	633	-	7,326
Nov.-23	269,657	2,352	34,861	2,625	88,624	1,220	139	7,321
Dec.-23	269,443	3,088	51,188	3,709	88,624	2,154	259	7,315
Jan.-24	303,067	3,111	52,644	3,907	90,462	2,463	234	7,452
Feb.-24	291,037	2,723	54,216	4,014	90,462	1,934	138	7,445
Mar.-24	293,337	3,012	55,149	4,047	90,462	2,215	243	7,437
Apr.-24	285,355	3,138	57,596	4,118	90,462	1,748	229	7,428
May-24	209,054	3,458	29,705	3,863	90,462	1,160	163	7,418

II. BASELINE USE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	RSG	GSG	LVG
Oct.	38.7	110.8	2,350.0
Nov.	87.6	172.0	3,486.2
Dec.	144.9	320.4	5,220.9
Jan.	180.6	421.1	6,506.4
Feb.	153.5	351.6	5,940.9
Mar.	124.5	275.8	5,478.7
Apr.	70.4	170.7	3,703.5
May	37.0	80.1	2,037.8
Jun.	21.0	49.2	1,477.0
Jul.	18.0	58.5	1,374.6
Aug.	18.0	50.5	1,379.9
Sep.	19.5	52.6	1,322.8
Total Annual	**913.7**	**2,113.3**	**40,278.7**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

2. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.9. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related deficiency in customer usage will be subject to a BGSS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 4.0 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Gas Net Plant (including the Gas allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV**. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM**

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 49
Original Sheet No. 50

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 51**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per Therm	Charge per Therm Including SUT
RSG	($0.064753)	($0.069043)
GSG	($0.054983)	($0.058626)
LVG	($0.025916)	($0.027633)
SLG	($0.094749)	($0.101026)
TSG-F	($0.022261)	($0.023736)
TSG-NF	($0.011569)	($0.012335)
CIG	($0.017044)	($0.018173)
CSG	($0.001181)	($0.001259)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 51 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 52**

DISTRIBUTION ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Distribution Adjustment Charge including New Jersey Sales and Use Tax SUT	$0.XXXXXX

Distribution Adjustment Charge

This charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 53**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$0.074813
Estimated Gulf Coast Cost of Gas	0.339920
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.049390)
Adjusted Cost of Gas	0.365343
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$0.372799
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 54 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 55**

BGSS-F
BASIC GAS SUPPLY SERVICE-FIRM
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULES GSG, LVG, SLG, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.499741
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.532849
FLOOR PRICE:	Non-Gulf Coast Cost of Gas component	$ 0.173461
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-F for the month	0.198685
	Total Cost of Gas	$ 0.372146
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.379741
CEILING PRICE:	Commodity Charge	$ 0.505582

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the applicable charge for Emergency Sales Service.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month plus other fixed adjustments of a negative $0.050515 per therm.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 55 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 56**

BGSS-I
BASIC GAS SUPPLY SERVICE-INTERRUPTIBLE
COMMODITY CHARGE APPLICABLE TO RATE SCHEDULES TSG-NF, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.462786
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.493446
FLOOR PRICE:	50% of the Non-Gulf Coast Cost of Gas component	$ 0.086730
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-I for the month	0.249200
	Total Cost of Gas	$ 0.335930
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.342786
CEILING PRICE:	Floor Price plus $0.18	$ 0.522786

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of 50% of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the Floor Price plus 18 cents per therm.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 56 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 57**

BGSS-CIG
BASIC GAS SUPPLY SERVICE – COGENERATION INTERRUPTIBLE
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE CIG
(Per Therm)

COMMODITY CHARGE:

Estimated Average Commodity Cost for the month	$ 0.249200
Variable Cost of Commodity and Fuel	0.000000
50% Weighted Average Pipeline Demand Costs	0.022352
Total Commodity Cost of Gas for the month	$ 0.271552
Total Commodity Cost of Gas after application of losses (Loss Factor = 2.0%)	$ 0.277094
Cogeneration Facilities in Service on or before March 10, 1997.	$ 0.277094
Cogeneration Facilities in Service after March 10, 1997 (Charges include New Jersey Sales and Use Tax)	$ 0.295451

Combined Commodity and Distribution Charge – Information Only:

Cogeneration Facilities in Service on or before March 10, 1997

Sum of a Distribution Charge of $0.088960 per therm for the first 600,000 therms used in each month plus the above Commodity Charge	$ 0.366054
Sum of a Distribution Charge of $0.078960 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge	$ 0.356054

Cogeneration Facilities in Service after March 10, 1997
(Charges include New Jersey Sales and Use Tax)

Sum of a Distribution Charge of $0.094854 per therm for the first 600,000 therms used in each month plus the above Commodity Charge	$ 0.390305
Sum of a Distribution Charge of $0.084191 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge	$ 0.379642

The monthly Distribution Charges for Rate Schedule CIG are shown on Sheet No. 107.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 57 filed with the BPU on July 28, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 58**

EMERGENCY SALES SERVICE
CHARGE APPLICABLE TO RATE SCHEDULES RSG, GSG, LVG,
SLG, TSG-F, TSG-NF, CSG
(Per Therm)

Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC)	$ 0.044850
Public Service's BGSS supplier(s)'s highest cost of gas purchased or used by Public Service during the month	0.269620
A charge of $0.181	0.181000
Total	$ 0.495470
Emergency Sales Service Charge after application of losses (Loss Factor = 2.0%)	$ 0.505582
Emergency Sales Service Charge including New Jersey Sales and Use Tax (SUT)	$ 0.539077

The charge for Emergency Sales Service will equal the sum of: (1) Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC); (2) Public Service's BGSS supplier(s)'s highest cost of gas purchased or used during that month, (including associated storage costs, if any); (3) a charge of 18.1 cents per therm; (4) application of losses; and (5) all other applicable taxes and surcharges.

This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Seventh Revised Sheet No. 58 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 59**

BGSS-RSGOP
BASIC GAS SUPPLY SERVICE-RSG OFF-PEAK

COMMODITY CHARGE APPLICABLE TO
RATE SCHEDULE RSG OFF-PEAK USE
(Per Therm)

Cost of Off-Peak RSG Gas Acquired	$ 0.263220
20% of the Non-Gulf Coast Cost of Gas seasonal component	0.010280
Total Cost of Gas	$ 0.273500
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.279082
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.297571

The Commodity Charge will be established on a level basis for the billing months of May to October immediately prior to the Off-Peak season of each year. The Commodity Charge will equal the Cost of Off-Peak RSG Gas Acquired (plus the variable pipeline transportation cost including fuel) and 20% of the Non-Gulf Coast Cost of Gas seasonal component. The Commodity Charge will be adjusted for losses.

The Cost of Off-Peak RSG Gas Acquired will be established prior to the beginning of the Off-Peak period based on the average NYMEX closing price for the first 15 days of April for natural gas to be supplied in the months of May through October.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 59 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on October 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES (Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 61 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 62
Original Sheet No. 63
Original Sheet No. 64

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 66**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Societal Benefits Charge, the Margin Adjustment Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the Distribution Charge for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:

A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:

In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-RSG.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 67**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 68**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) This rate schedule is available where all service is for residential purposes:

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In residential premises where customer's use of gas service for purposes other than residential is incidental to the customer's residential use;

(a-3) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-4) In separately metered individual flats or apartments in multiple-family buildings;

(a-5) In multiple-family buildings of two or more individual flats or apartments where gas service is measured by one meter and is furnished to the tenants or occupants of the flats or apartments by the owner. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not;

(a-6) In multiple-family buildings of two to four individual flats or apartments where gas fired equipment serves multiple flats or apartments. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not.

(b) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 69**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

(c) **Off-Peak Use**: Limited to customers with gas central air-conditioning equipment having a rated capacity of not less than two tons of refrigeration. For all eligible customers the Distribution Charge for the therms used for all purposes in excess of 50 therms in any month during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(d) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(e) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(f) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(g) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS's deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 70
Original Sheet No. 71

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 73**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 74**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 75**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) **Off-Peak Use:** This separately metered gas service is applicable for cooling or dehumidification when supplied through a separate meter. For all eligible customers the Distribution Charge for the therms used during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

(c) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 76**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

(e) **Unmetered Service:** Unmetered service will be furnished, at the discretion of Public Service, for customer owned and installed gas lamps or other continuous burning devices. No other gas using devices shall be connected to this service. The customer shall provide, at the customer's expense, all necessary equipment and piping after the gas Service Connection. Further, the customer may be required to furnish and install, at the customer's own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense. Customer shall notify Public Service in writing as to changes in conditions or operation that may affect the gas consumption of the connected device(s). Public Service reserves the right to meter any and all such installations where customer does not comply with the requirements of this Special Provision.

(f) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(f-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(f-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 77**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(g) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(h) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(i) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(j) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 78**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.3754	$4.6653	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.033054	$0.035244	$0.050101	$0.053420

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 80**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Margin Adjustment Charge:
This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 81**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (f) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 82**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 83**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

(c) Where Public Service is unable to read the meter on a regular basis, Public Service may require the installation of a remote meter reading device at the customer's expense.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(e) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(e-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(e-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 84**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(f) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(g) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(h) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(i) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 85
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 87**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Lamps, posts, maintenance, and firm delivery service for street lighting purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Monthly Charge Per Unit (Includes lamp, post, maintenance and firm delivery service):

Lamps Installed Prior to January 1, 1993:

	Charges	Charges Including SUT
Single–mantle lamp	$ 13.2351	$ 14.1119
Double–mantle lamp, inverted	13.2351	14.1119
Double-mantle lamp, upright	13.2351	14.1119
Triple–mantle lamp	13.2351	14.1119

Lamps Installed on or after January 1, 1993:

	Charges	Charges Including SUT
Triple–mantle lamp	$ 67.4762	$ 71.9465

Allowance for Lamp Outages:

The Monthly Charge per unit reflects an outage allowance based upon normal operating conditions. No further allowance will be made.

Distribution Charge per Therm:

Charge	Charge Including SUT
$0.053531	$0.057077

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 88**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 89**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for the BGSS-F commodity charge.

OTHER CHARGES:

See Special Provision (e) below.

BILLING DETERMINANTS:

Therms:
The number of therms used are shown below for each lamps type.

Single-mantle	0.69 therms per day
Double-mantle, inverted	0.77 therms per day
Double-mantle, upright	1.37 therms per day
Triple-mantle	0.77 therms per day

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by multiplying the number of days in the billing month by the above listed daily usage values in therms, adjusted for losses, for each lamp type times the number of customer lamps. If the customer has multiple lamp types then the DCQ would be the sum from all lamp types calculated in the preceding manner. Public Service may adjust customer's DCQ during the year, due to changes in the number and types of customer's lamps.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Five years; written contract required.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 90**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(b) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(c) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(d) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(e) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 91
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 93**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule since December 1, 1994, with the exception of any new customers for whom commitments by Public Service had been made prior to December 1, 1994.

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery, subject to Public Service's available capacity to provide such service, where the maximum requirement for firm gas is not less than 150 therms per hour and where the customer's Third Party Supplier (TPS) and/or its agent has arranged for the delivery of gas supplies to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver the customer's purchased gas supply.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$2.1896	$2.3347	per Demand Therm

Distribution Charges:

Charge	Charge Including SUT	
$0.083696	$0.089241	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 94**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the requirement of the Third Party Supplier Requirement portion of this Tariff, Public Service may supply the deficiencies as Emergency Sales Service. Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm sales obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 95**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be restricted to the maximum annual, daily and hourly requirements, and the location and equipment specified in the service agreement. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement.

(b) The customer must contract with a TPS to arrange for deliveries to Public Service of its daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

Details for third party supply can be obtained by referring to Section 14 – Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff.

(c) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(d) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(e) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 96**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

(f) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205(a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 97
Original Sheet No. 98

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 99**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Interruptible delivery for general purposes where the maximum requirement for interruptible gas is not less than 150 therms per hour and where the customer has the installed capability to utilize an alternate type of fuel, except as provided for in Special Provision (a). Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.098680	$0.105218	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

This charge does not apply to gas sold to customer by Public Service pursuant to Special Provision (d).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 100**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers with a maximum requirement of less than 2,000 therms per hour and who do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Interruptible (BGSS-I) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

OTHER CHARGES:

See Special Provisions (d) and (e).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 101**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERM:

Unless otherwise agreed upon by customer and Public Service**,** one year from the commencement date specified in the service agreement required by Special Provision (a) and successive one-year periods thereafter. Service may be terminated by either customer or Public Service by providing no less than one month's notice prior to the expiration of the term.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum annual, daily, and hourly requirements, and the location and equipment specified. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement. Attached to the service agreement will be a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(b) Customers who were taking service under former Rate Schedule ISG Special Provision (b) on January 8, 2002 will be provided service under this rate schedule and are exempt from the minimum connected load requirement of 150 therms per hour.

(c) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(d) If customer does not discontinue the use of gas after notification pursuant to Special Provision (c) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 102**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (c), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (c) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(e) If a customer requests a change from this delivery rate schedule to firm service firm service will be available on a prospective basis subject to the availability of supply and delivery capacity, If a customer switches to firm service, they must remain on firm service for at least one year. If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.

(f) Customer may be required to make a deposit toward the total cost of facilities which Public Service installed to provide service if gas equipment or applications were, in the prior five-year period, previously served under Rate Schedules RSG, GSG, LVG or TSG-F for the same customer. Such deposit will be determined as if such gas equipment or applications had been served under Rate Schedule TSG-NF for the entire period served under the above firm rates, utilizing the deposit calculations in existence at the time the customer began service.

(g) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Except as provided in Special Provision (a) customer has installed and maintains complete and adequate standby equipment and fuel supply for operation with another fuel when the gas supply is interrupted.

(j) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. If the customer obtains gas supply from a TPS, these personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff. If the customer obtains gas supply from Public Service under BGSS-I default service, Public Service may establish similar operational coordination requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 103**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

(k) Service under this rate schedule is not available for resale.

(l) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(m) Military Service: United States Department of Defense Military bases may apply for service under this special provision. Under this special provision: 1) a customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements of this Tariff; 2) delivery service will not be interrupted with respect to the customer's gas that is delivered to Public Service by the customer's TPS on any day; 3) all service for each service location must be through a single meter; 4) the requirements for an alternate fuel shall not apply; and 5) in lieu of the annual alternate fuel certification required by each November 1st as described in Special Provision (a) above, the customer is required to submit a certification by each November 1st that it has a contract with a TPS to supply its gas requirements each day through the end of the following March.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(n) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(o) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 104
Original Sheet No. 105
Original Sheet No. 106

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 107**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule or former Rate Schedule CEG since January 8, 2002, with the exception of any new customers for whom commitments by Public Service had been made prior to January 9, 2002.

APPLICABLE TO USE OF SERVICE FOR:

Interruptible gas delivery and supply service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utility Regulatory Policies Act of 1978, and regularly meeting the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b) and where the combined nameplate-rated capacity of the generation equipment is not less than 1.5 megawatts and not greater than 20 megawatts. This size limitation shall not apply to customer's Qualifying Facilities receiving service under this rate schedule prior to January 1, 1993.

DELIVERY CHARGES:

Service Charge:

$199.11 in each month [$212.30 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.088960	$0.094854	per therm for the first 600,000 therms used in each month.
$0.078960	$0.084191	per therm in excess of 600,000 therms used in each month.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

This charge does not apply to gas sold to customers by Public Service pursuant to Special Provision (c).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 108**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

COMMODITY CHARGES:

Customers taking service under this rate schedule are required to receive their commodity service from Public Service. Refer to the BGSS-CIG Commodity Charge sheet of this Tariff for the current charge.

Other Charges:
See Special Provisions (c) and (n).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer must certify that qualifying status has been granted by the Federal Energy Regulatory Commission and will be required to sign a service agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in that service agreement. Upon request by customer, Public Service may deliver available volumes of gas in excess of the maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in that service agreement.

(b) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 109**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(c) If customer does not discontinue the use of gas after notification pursuant to Special Provision (b), the Commodity Charge shall be $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a per therm quantity not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey." This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (b), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis, subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to supply gas at any time following notice pursuant to Special Provision (b) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

If a customer requests a change from this delivery rate schedule to firm service, firm service will be available on a prospective basis subject to the availability of supply and delivery capacity. If a customer switches to firm service, they must remain on firm service for at least one year,

(d) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(e) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes.

(f) Service will not be supplied under this rate schedule and any other gas rate schedule for the same process or operation at the same location except as specified under Special Provision (i).

(g) Public Service agrees that service under this rate schedule will not be interrupted unless service to the TSG-NF customers receiving BGSS-I default service has already been interrupted.

(h) Gas supplied under this rate schedule is limited to a quantity equal to the lesser of either 0.150 therms for each net kilowatt-hour of cogenerated electric generation fueled by gas or the quantity of gas actually consumed by the cogeneration facility when operated in a cogeneration mode as determined by Public Service. Net cogenerated electric generation is defined as generation output less energy used to run the cogeneration facility's auxiliary equipment. Auxiliary equipment includes, but it is not limited to, forced and induced draft fans, boiler feed pumps and lubricating oil systems.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 110**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(i) Gas supplied in excess of the quantity described in Special Provision (h) will be billed under an applicable rate schedule as determined by Public Service except as specified under Special Provision (c).

(j) Net cogenerated electric generation fueled by natural gas will be determined each month as follows:

(j-1) For facilities which burn two or more fuels simultaneously for cogeneration, net cogenerated electric generation will be allocated between such fuels on the Btu input of each fuel.

(j-2) For facilities which change fuel usage between gas and an alternate fuel for cogeneration, net cogenerated electrical generation fueled by gas will be based on meter readings taken by the customer at the time the fuel change occurs or the portion of the allocated amount determined in Special Provision (h) prorated by the number of hours or days that the customer used gas.

(k) Public Service, at its sole discretion, may utilize readings from customer or Company-owned meters to determine the quantity of gas to which this rate schedule is applicable in lieu of the allocation specified in Special Provision (j-1). The customer shall make available, and Public Service shall have the right to read, inspect and/or test such customer-owned meters during normal working hours. Additional gas, electric and/or useful thermal output meters required to determine the amount of gas to which this rate schedule is applicable will be installed, owned and operated by Public Service. However, Public Service may, at its sole option, use calculated or estimated data to determine such gas usage.

(l) Customer is required to file a monthly report to Public Service containing the total amount of kilowatt-hours produced by the cogeneration facility.

(m) Service under this rate schedule is not available for resale.

(n) **Extended Gas Service:** Gas service under this Special Provision is limited to customers having an executed service agreement for this Special Provision. Customer's executed service agreement must be received by Public Service no later than November 15th for service to be provided for the upcoming winter season. Approval of the customer's request will be provided on a case by case basis so as not to adversely impact Public Service's distribution system. When service under this Rate Schedule is interrupted, service under this Special Provision will be supplied at Public Service's option. When Extended Gas Service is offered by Public Service, the following provisions shall apply:

(n-1) In lieu of the Therm Charge hereinbefore set forth, the following charges shall apply: 1) a Special Delivery Charge which, based upon the marketability of this gas, would fall between a floor price of $0.100 ($0.107 including SUT) per therm and a ceiling price of $0.180 ($0.192 including SUT) per therm for each therm of Extended Gas Service supplied to the customer; and 2) a Commodity Charge which shall be the maximum of the "Common" range value stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Zone 6 New York for the day(s) when service under this Special Provision is offered.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 111**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(n-2) A service agreement for this Extended Gas Service shall be executed for each winter season and shall include the customer's maximum daily requirements under this Special Provision and a prepayment equal to four days of the Special Delivery Charge at a rate of $0.150 ($0.160 including SUT) per therm at the customer's maximum daily requirement. Use of gas above the maximum daily requirement, on any day for which Public Service has offered and the customer has requested Extended Gas Service, will be subject to the penalty as stated in Special Provision (c). Such prepayment shall be non-refundable unless and to the extent that Public Service does not offer customer such Extended Gas Service for at least 96 hours, during the winter season. If Public Service, offers such service for less than 96 hours, the refund shall be made on a prorated basis. In addition to such prepayment, a non-refundable application charge of $800.00 ($853.00 including SUT) shall be paid by each customer.

(n-3) Customer will be notified electronically or by phone of the Extended Gas Therm Charge at least eight hours prior to the availability of this service, or prior to a change in the Extended Gas Therm Charge. Following receipt of Public Service's notice, the customer will have two hours within which to electronically notify Public Service the customer's acceptance of the Extended Gas Therm Charge for the service. If customer does not accept this service, customer must discontinue the use of gas at the time designated by Public Service, which time shall not be less than eight hours after Public Service's notice to Customer of the availability and the Therm Charge of the Extended Gas Service. Any gas usage by customer following the time designated by Public Service shall be subject to the penalty as stated in Special Provision (c).

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c.57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112**

RATE SCHEDULE CSG
CONTRACT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Public Service will review all applications to verify for completeness within 45 days of receipt. If any data is missing, Public Service will notify customer of the information needed to complete the application. Public Service reserves the right to request additional information as needed on a case by case basis. Once a request is deemed complete, Public Service will have 45 days to complete its analysis and respond to the customer. Once agreement has been reached, Public Service will forward the application to the Board of Public Utilities for review and approval. Once approved by the Board of Public Utilities, the customer agrees that the discounted rate set forth under this rate schedule will not be confidential.

Customers may purchase gas supply from a Third Party Supplier (TPS) or, for customers with a maximum requirement of less than 2,000 therms per hour, from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

ECONOMICALLY VIABLE BYPASS

For all customers requesting this tariff service based on an economically viable bypass alternative, the customer must submit to Public Service the following minimum information but not limited to:

1. A bypass feasibility report issued by the interstate pipeline or an independent engineering consultant setting forth:
    i. Maps showing the route of the potential bypass;
    ii. Flow diagrams showing the major components of the bypass from the interstate pipeline interconnection to the customer;
    iii. Engineering studies related to the proposed cost to bypass including estimated costs for: right-of-way; regulatory approvals; material; equipment; structures; construction; overheads; contingencies and tax gross-up applicable to pipeline company facilities;
    iv. The location class, design pressure, size, length, pipe specification, yield strength and wall thickness of the bypass pipeline;
    v. Schedule of all permits from State or Federal agencies and railroads necessary for the bypass;
    vi. Project schedule;
    vii. The cost estimate classification level following AACE International Recommended Practice No.18R-97;
    viii. Statement from the interstate pipeline that the proposed interconnection is operationally viable and that the pipeline can effectuate service as requested.
2. Creditworthiness of customer.
3. Estimated annual therm usage along with all supporting assumptions and calculations.

OTHER CONSIDERATIONS

Service under this rate schedule where the customer is requesting this tariff service based on considerations other than an economically viable bypass alternative will be offered by the Company in circumstances in which it determines in its sole reasonable judgment that such rates are necessary to prevent (i) economic bypass of the Company's distribution system, or (ii) the loss of load that could otherwise be served at rates that exceed marginal costs.

Customer seeking negotiated rates under this provision must provide the Company: (i) such information as the customer deems relevant to its request; (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms or conditions under this provision to a particular customer, the Company will consider all relevant information provided by the customer and make a judgment as to whether or not the negotiated rates are necessary to prevent an economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112B**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.
The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

OTHER CONSIDERATIONS
DELIVERY CHARGES:
The Delivery Charges shall be set to be sufficient to recover revenues in excess of marginal costs for Public Service to provide service to the customer under this rate schedule. Delivery Charges will be based on agreement reached with Public Service and approved by the Board of Public Utilities.

COMMODITY CHARGES:
A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) For customers with a maximum requirement of less than 2,000 therms per hour, Public Service through its Basic Gas Supply Service default service. Such supply service may be either firm or interruptible. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
Emergency Sales Service is only available for customers with a maximum requirement of less than 2,000 therms per hour.

In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
A customer with a Maximum Requirement of less than 2,000 therms per hour that does not receive gas supply from a TPS will be supplied, at the customer's option, under either the Basic Gas Supply Service – Firm (BGSS-F) default service or the Basic Gas Supply Service-Interruptible (BGSS-I) default service as applicable based on whether Customer is being provided firm or interruptible service pursuant to this Rate Schedule. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge or to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112C**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:
See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:
If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period. This charge applies to both Economically Viable Bypass customers and Other Consideration customers.

BILLING DETERMINANTS:
Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:
Estimated annual therm usage (see Item 3, Tariff Sheet 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:
a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:
The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112D**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Distribution Charge Factor: per $ of Net Alternative Delivery Cost

Term	Monthly Factor	Monthly Factor Including SUT
5 Years	$0.025583	$0.027278
10 Years	0.015773	0.016818
20 Years	0.010716	0.011426

Maintenance Charge Factor: per $ of Alternative Delivery Cost

Term	Monthly Charge	Monthly Charge Including SUT
5 Years	$0.000262	$0.000279
10 Years	0.000276	0.000294
20 Years	0.000300	0.000320

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Up to twenty years from the commencement date specified in the service agreement required by Special Provision (a), which length to be determined by agreement of the parties or, in the case of an economically viable physical bypass, based on the length of financing offered by the interstate pipeline company. The Distribution Charge and the Maintenance Charges as of the commencement date will remain unchanged for the term of the service agreement. The customer may terminate service by providing no less than one month's notice. Customers shall be required to make a termination payment for all such service terminated prior to the end of the Term equal to 50% of the sum of the Distribution Charge multiplied by the Contract Monthly Therms multiplied by the number of months remaining for the term of the service agreement. The termination payment shall be due to Public Service upon the date the termination becomes effective pursuant to the customer's notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum daily capacity of the alternative delivery option used to determine the Monthly Distribution Charge. Deliveries in excess of the maximum specified in such service agreement will require the establishment of an additional new service agreement and related monthly charges, where such charges for such excess capacity shall be based upon the then current costs for such alternative delivery option and the then current pricing factor.

(b) Upon advanced written notice to Public Service, such service agreement shall be transferable to a new customer or owner of the facility at the location specified in the service agreement.

(c) Requests for a change between interruptible delivery service under this rate schedule to or from firm delivery service under this rate schedule will require the establishment of a new service agreement and new term of service based on the then current costs and pricing factor. There shall be no termination payment required related to a change from interruptible delivery service to firm delivery service under this rate schedule. A change from firm delivery service to interruptible delivery service will require a termination payment as detailed above.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112E**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

(d) For customers with a maximum requirement of 2,000 therms per hour or greater, Public Service reserves the right to discontinue delivery service at any time the total imbalance cash-out amounts unpaid, including amounts billed and amounts not yet billed, by the customer's TPS are greater than 90% of the current credit Security amount held by Public Service for the customer's TPS in accordance with Section 5 of the Third Party Supplier Requirements of this tariff.

(e) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. These personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff.

(f) Where the customer has selected BGSS-I as their gas supply option or is supplied interruptible delivery service under this rate schedule, the following shall apply:

(f-1) The customer shall provide a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(f-2) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service by telephone, or other electronic means, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(f-3) If customer does not discontinue the use of gas after notification pursuant to Special Provision (f-2) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a use rate per hour not greater than 5% of customer's maximum hourly requirement.

The charge for all additional gas used shall be ten times the highest price of the daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112F**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

If a customer supplied under Rate Schedule BGSS-I persistently does not discontinue the use of gas after notification pursuant to Special Provision (f-2), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under interruptible supply service Rate Schedule BGSS-I. Applicable firm supply service will be available on a prospective basis under Rate Schedule BGSS-F subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (f-2) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(g) Unless otherwise agreed to by Public Service, metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Service under this rate schedule is not available for resale.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SERVED BY THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(j) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(k) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customers eligible to receive Emergency Sales Service can change TPSs effective only on the first day of the month. Customers not eligible to receive Emergency Sales Service can change TPSs at any time in the event that their TPS fails to deliver supply.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 113**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 114**

THIRD PARTY SUPPLIER REQUIREMENTS

1. GENERAL

A Third Party Supplier (TPS) of natural gas is an entity that has contracted with customers of Public Service to deliver supplies of natural gas to interconnection points with Public Service's distribution system, or is a customer who is self-supplying and acting as a TPS on their own behalf in purchasing and transporting natural gas to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver on a firm basis these gas supplies to the customer pursuant to Rate Schedules RSG, SLG, GSG, LVG, TSG-F, or CSG and on an interruptible basis to customers pursuant to Rate Schedules TSG-NF or CSG. In order for an entity to qualify as a TPS it must execute an Application for Service and satisfy Public Service's credit requirements as noted herein. In order for a customer to qualify to self-supply, the Public Service customer of record for gas delivery service must be served on Rate Schedule TSG-NF or CSG and must be the same corporate entity that is purchasing and transporting the natural gas to interconnection points with Public Service's distribution system. A self-suppling customer must meet all of the TPS requirements herein, except the requirement for licensure by the Board of Public Utilities. TPSs, other than qualifying self-supplying customers, must be licensed by the Board of Public Utilities (Board).

A TPS must successfully complete all Electronic Data Interchange testing in order to enroll new customers that receive service under Rate Schedules RSG, GSG, LVG, SLG, TSG-F, TSG-NF, and CSG.

TPSs agree to abide by the Board's regulations and with N.J.A.C. 14:4 *et seq*., *Energy Competition,* including but not limited to Subchapter 7 *Retail Choice Consumer Protection.* Public Service is not responsible for the administration or the enforcement of either of the aforementioned regulations or Code.

2. CUSTOMER CONFIRMATION

By the twenty-second (22nd) of each month, for service to RSG, SLG, GSG, or LVG which is to commence on the first (1st) of the next calendar month, Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes: (1) those customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS, including their required Daily Contract Quantity (DCQ), expressed in therms; (2) former customers' applicable imbalances, expressed in therms; and (3) the TPS's Aggregate Daily Contract Quantity (ADCQ), adjusted for losses, expressed in dekatherms, equal to the sum of the DCQ's of each of the customers of that TPS. TPS will be required to notify Public Service by electronic or other means, as specified by Public Service, by the twenty-second (22nd) of the month as to any corrections or changes to their list of customers, otherwise the list will be assumed to be accurate. Public Service will only amend the list of customers and their respective DCQ's in accordance with the above procedures prior to the next month if a good faith dispute arises concerning the respective TPS's list.

Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes those TSG-F, TSG-NF, and CSG customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS.

3. DELIVERY

3.1 **General:** Subject to the Force Majeure provisions in Section 7, TPS must deliver to Public Service on each day of the month at points specified on Public Service's distribution system, which points are operationally acceptable to Public Service in its sole discretion, the ADCQ for its RSG, SLG, GSG, and LVG customers and the daily or, under certain circumstances, the hourly usage of its TSG-F, TSG-NF, and CSG customers, adjusted for losses (hereinafter collectively referred to as "usage"). Failure to comply with this provision shall subject TPS to the cash-out pursuant to Sections 6.1, 6.2, and/or 6.3.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 115**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

3.2. Warranty of Title: TPS warrants that, at the time of delivery of gas to Public Service, it will have good title to deliver all gas volumes made available.

3.3. Delivery Control and Possession: After TPS delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

3.4. Delivery Liability: Public Service shall in no way be liable for any errors in the calculation of the DCQ or ADCQ, nor be responsible for any additional gas costs incurred by TPS due to any error in the calculation of the DCQ or ADCQ.

3.5. Delivery Allocation: On each day deliveries of gas by TPS to Public Service shall be first allocated to TPS's ADCQ on such day and any remaining volume shall be allocated to TPS's TSG-F, TSG-NF, and CSG customers.

4. NOMINATION PROCEDURES

4.1. General: Unless otherwise provided for under section 4.3, Public Service will provide TPS(s) notice by July 1 of each year of the allocation of receipt capacity by pipeline that it expects to have available for all deliveries by TPS(s) at its city gate interconnections, based on existing contractual commitments, for the twelve (12) month period beginning the following November 1. Each TPS(s) will be allocated the receipt capacity based on the total expected firm and interruptible load versus the amount of available receipt capacity.

TPS will be credited for deliveries to Public Service on each day in accordance with the final daily volume confirmations of the interstate pipelines designated by TPS pursuant to this Sub-section.

4.2. TPS Nomination Requirements: TPS will be required to nominate to Public Service by electronic or other means, as specified by Public Service, the total volume it intends to deliver to Public Service for subsequent delivery, along with the interstate pipelines it intends to utilize for this delivery and any additional information required by Public Service to fully identify such deliveries. TPS shall nominate to Public Service by 2:30 p.m. Eastern Time prior to the day gas is scheduled to flow (ie. the "Gas Day", defined as the 24 hour period commencing at 10:00 AM Eastern Time). TPS will be permitted to submit requests to modify nominations after the 2:30 pm deadline for supplies for the Gas Day, which may include modifications to both pipeline contracts and volumes. Such modifications will be consistent with the prevailing NAESB protocols, of 7:00 PM Eastern Time on the day prior to the Gas Day, and 11:00 AM Eastern Time ("Intra-day 1"), 3:30 PM Eastern Time ("Intra-day 2"), and 8:00 PM Eastern Time ("Intra-day 3") during the Gas Day. Any such requests for modifications to nominations for a Gas Day must be submitted in writing and received by Public Service up until 8:00 PM Eastern Time during the applicable Gas Day. Public Service will not be obligated to accept gas which has not been nominated in accordance with this Section. In any event, Public Service may refuse any revision in the nomination made during the day of delivery for operating reasons, and if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.

Public Service will accept deliveries of gas for customers on the interstate pipelines of Transco or Texas Eastern. However, due to delivery limitations, Public Service reserves the right to require a reasonable apportionment of deliveries between Transco and Texas Eastern.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 116**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5. CREDIT REQUIREMENTS

5.1. **General:** Public Service's acceptance of a request for service under these Third Party Supplier Requirements is contingent upon TPS providing Security in an amount determined by Public Service.

A TPS may provide one of the following additional credit assurances to meet its Security obligation: (1) an advance cash deposit; or (2) a standby irrevocable letter of credit.

5.2. **Credit Amount:** The total Security at all times must be of an amount not less than the product of the TPS's Daily Requirements, expressed in dekatherms, and $70.00, plus the amount of balancing cash-out obligations outstanding to Public Service, whether billed or not billed, such total amount rounded down to the next lower multiple of $15,000. Daily Requirements is defined as the sum of the TPS's maximum month ADCQs for RSG, SLG, GSG and LVG customers and the total of the maximum month average daily usage for TSG-F, TSG-NF, and CSG customers, as stated in their respective service agreements. At any time, the maximum month's value shall be the greatest total ADCQ or average daily usage, as applicable, in the prior 12 month period (otherwise known as a rolling 12 month period).

If, at any point in time, the TPS's Daily Requirements decreases, TPS has the option to reduce the level of the Security to the product of the new Daily Requirements and $70.00, after all the outstanding obligations payable to Public Service are satisfied.

In all cases, any required increase in the level of Security must be satisfied within two (2) business days after receipt of the Public Service notice for additional Security requirements to continue service. If such Security is not posted in accordance with the foregoing, then Public Service is not required to continue service.

5.3. **Interest:** Interest, on cash deposited with Public Service as Security, will be the lower of the average Federal Funds Effective Rate (as published daily on the Federal Reserve website) for the period of time the funds are on deposit or six (6) percent. Cash deposits shall cease to bear interest upon discontinuance of service by the TPS or, if earlier, when Public Service closes the account. When the executed service agreement is terminated or when a portion of the cash deposit is returned to the TPS, such cash deposits will be returned with accrued interest upon payment or deduction of all charges and other debts that the TPS might owe Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 117**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5.4. Failure to Deliver for Customers on Rate Schedules RSG, SLG, GSG, and LVG: In the event that, for a particular TPS, at any time, the sum of the cumulative imbalances, for non Force Majeure reasons, which Public Service has not yet received payment are underdeliveries that exceed three (3) times the ADCQ, Public Service will immediately notify the TPS via telephone, electronic, or similar means. If such underdeliveries reach five (5) times the ADCQ, the following will occur: (1) the TPS is no longer eligible for these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month; and (2) for the balance of the current month, the affected TPS's customers will be supplied natural gas by Public Service and will be billed for Emergency Sales Service pursuant to their rate schedules for their DCQ times the number of days remaining in the current month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS pursuant to Section 14.3 of the Standard Terms and Conditions or from BGSS default service pursuant to Section 14.5 of the Standard Terms and Conditions.

In order to be reinstated as an eligible TPS following an occurrence of an under-delivery event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an under-delivery event as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2. If an additional under-delivery event as described above occurs during that year period, the TPS will be ineligible for these Third Party Supplier Requirements for an additional one (1) year period.

5.5. Failure to Deliver for Customers on Rate Schedules TSG-F, TSG-NF, and CSG: In the event that, for a particular TPS, at any time, the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 70% of the current level of Security, Public Service will immediately notify the TPS via telephone, electronic, or similar means.

At this time the TPS will be given the option to increase the total amount of Security held by Public Service to the required amount as described in Section 5.2 of these TPS Requirements within two (2) business days or to provide immediate payment on outstanding amounts, whether billed or not billed, due to Public Service.

At such time the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 100% of the current level of Security, the TPS is no longer eligible under these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month. The affected TPS's customers eligible for Emergency Sales Service will be supplied natural gas by Public Service for their usage for the remainder of the month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS or from BGSS default service. Delivery service to customers not eligible for Emergency Sales Service will be ceased until such customers arrange for gas supplies from an eligible TPS.

In order to be reinstated as an eligible TPS following an occurrence of event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an event in which outstanding obligations, whether billed or not billed, exceed Security as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 118**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

If an additional event in which outstanding obligations, whether billed or not billed, exceed Security as described above occurs during that year period, the TPS will be ineligible under these Third Party Supplier Requirements for an additional one (1) year period.

6. IMBALANCE CASH-OUT PROCEDURES

6.1. TPS Imbalance Cash-out for Customers on Rate Schedules RSG, SLG, GSG, and LVG: On any day that TPS delivers a volume other than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

6.1.1. Over deliveries: On any day that TPS delivers a volume greater than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

The TPS will be cashed out each day for over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For over deliveries of the ADCQ of less than 5% the PSE&G will cash out the TPS for the excess gas at 90% the index. For over deliveries of the ADCQ greater than or equal to 5% but less than 15% PSE&G will cash out the TPS for the excess gas at 75% of the index. For over deliveries of the ADCQ greater than or equal to 15% but less than 25%, PSE&G will cash out the TPS for the excess gas at 50% of the index. For over deliveries of the ADCQ greater than or equal to 25%, PSE&G will cash out the TPS for the excess gas at 40% of the index.

6.1.2. Under deliveries: The TPS will be cashed out each day for under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For under deliveries of the ADCQ of less than 5% PSE&G will cash out the TPS for the deficiency at 110 % of the index cost times the under delivered quantity. For under deliveries of greater than or equal to 5%, PSE&G will cash out the TPS for the deficiency at 200% of the index.

6.1.3. Balancing during Critical Periods: Upon no less than eight (8) hours' notice, Public Service may on any days that it determines that its gas supply condition is critical, declare such days to be a "Critical Period." For any under deliveries by a TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will pay a charge per dekatherm at a rate equal to ten times the daily price index calculated in paragraph 6.1.1. The resulting price index shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC- approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. In addition, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs. For all over deliveries by an eligible TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 119**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2. TPS Imbalance Cash-out for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for their applicable customers at the same daily rate that the aggregate of their applicable customers are utilizing gas. The Daily Cash-out Price for over- or under deliveries by a TPS for any day will be the weighted average of the higher of lower of the "Common" range values stated in the Final Daily Price Survey section of Platt's *Gas Daily* for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights for the weighted average shall be the required percentages of natural gas delivered on the Texas Eastern and Transco pipelines. Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any underdeliveries by eligible TPSs.

Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.2.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

6.2.2. Normal Daily Balancing for Over-deliveries. The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery.

.Imbalance Level Credit to TPS

0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 120**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2.3. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

6.3. TPS Imbalance Cash-out for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for each of their applicable customers at the same daily rate each customer is utilizing gas. Except as provided for in Section 6.3.5 below, or as specified in the applicable TSG-NF or CSG agreement, all balancing and cash-out calculations shall be performed separately for each applicable customer. The basis for the Daily Cash-out Price for over- or under deliveries by a TPS will be the weighted average of the higher or lower of the "Common" range value(s) for Texas Eastern M-3 and/or Transco Zone 6 New York, as applicable. The weights for the weighted average shall be based upon the required delivery on the interstate pipeline(s) by the TPS, as published in Platt's *Gas Daily* on the table "Final Daily Price Survey". Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs.

If at any time customer's TPS fails to deliver, or arrange for delivery of a quantity of gas, which is consistent with the quantity of gas being consumed by customer, Public Service, in its sole discretion, may suspend deliveries of gas to customer until such time as the delivery of gas to Public Service is equal to the quantity of gas being consumed by customer commences. Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.3.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 121**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.2. Normal Daily Balancing for Over-deliveries: The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery

. Imbalance Level Credit to TPS

0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
> 5% to < 15%	5% < over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

6.3.3. Balancing During Periods of Suspension or Limitation: If at any time any customer is consuming gas at a rate other than a uniform hourly rate or consuming gas at a rate that doesn't correspond with the customer's TPS' deliveries, and Public Service determines that in its sole judgment that the integrity of all or a portion of its gas distribution system is being jeopardized because of such action, or the interstate pipeline upon which such gas is being delivered to Public Service enforces uniform hourly take restrictions, Public Service may limit the total amount of gas delivered to a TPS's customer to the same hourly rate at which the TPS is delivering gas to the Public Service gas system.

Public Service will provide the TPS two hours' notice that it intends to suspend or limit deliveries of gas to one or more customers, except in the case of an emergency on the Public Service gas distribution system or when the interstate pipeline enforces uniform hourly take provisions, in which case the TPS shall be notified as soon as practicable. Such notice from Public Service shall indicate the action Public Service intends to take with respect to suspending or limiting deliveries to a customer, the estimated time period of such suspension or limitation, and the time when such suspension or limitation shall go into effect.

If, during such a period of suspension or limitation of service, the TPS delivers a quantity of gas that is inconsistent with such suspension or limitation, then all under deliveries by the TPS greater than two (2) percent will be cashed out at five times the Daily Cash-out Price. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

6.3.4. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 122**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.5. Designated Personnel: The customer's designated personnel having operational control of the gas usage at that facility shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS. Such personnel shall be the only party that Public Service contacts for all operational coordination requirements, including those during periods of Suspension or Limitation and Critical Periods as detailed in Sections 6.3.2 and 6.3.3.

6.4. Cash-out Billing and Payment: Public Service will invoice the TPS any cash-out costs and these charges are due within ten (10) days of the date of Public Service's invoice. Such bills will be subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Public Service has the right to call on Security in an amount equal to all unpaid cash out costs within 30 days of issuance of the cash-out invoice unless Public Service has agreed in writing to extend the period for repayment. Public Service will notify the TPS of the amount of the Security used and the amount of additional security that the TPS shall be required to post. The TPS is required to replenish this Security withing two (2) business days as described in Section 5.2 of these Third Party Supplier requirements.

It is the obligation of the TPS to provide Public Service with contact information for cash-out billing annually, and timely notification of any subsequent change to those billing contacts.

Notwithstanding the above, Public Service maintains the right to suspend transportation deliveries to any customer under Rate Schedules RSG, SLG, GSG, LVG, TSG-F, TSG-NF, and CSG from a particular TPS, and return such customers to BGSS, if in Public Service's sole opinion that TPS is not satisfying the TPS requirements as specified herein. Such TPS may also be disqualified from enrolling new customers.

7. FORCE MAJEURE

If an interstate pipeline that deliveries gas to PSE&G's system has declared a Force Majeure event, pursuant to the terms of that pipeline's FERC approved tariff, that substantially affects the ability of a TPS to deliver the required ADCQ on any given day, Public Service may

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 123**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

excuse a TPS from performing pursuant to Sections 6.1, 6.2 and 6.3 of these Third Party Supplier Requirements to the extent of such curtailment, and may cash-out the TPS for related under-deliveries at the higher of the (i) weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day (the weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points), or (ii) the Company's average cost of supply for the period in question (inclusive of any pipeline penalties assessed on the Company). The TPS is responsible for supplying complete information and verifiable proof of all the particulars requested by Public Service related to any such Force Majeure exclusion. The TPS must have a firm, non-interruptible service with the affected pipeline that is covered by the Force Majeure event and must be willing to present such agreements to Public Service.

8. STANDARD TERMS AND CONDITIONS

These Third Party Supplier Requirements are subject to the Standard Terms and Conditions of this Tariff, as applicable.

Item	Sheet No.		Description
Table of Contents	Original Sheet No. 2		Updated page numbers and inserted line for proposed new Distribution Adjustment Charge
Standard Terms & Conditions	Original Sheet No. 9		Updated the address for Board of Public Utilities.
			Updated methods for application of service
	Original Sheet No. 14		§ 3.7.1. a) Correction to holding deposits without interest
	Original Sheet No. 19		§ 6.3. – Added language to ensure Company access to meters
	Original Sheet No. 22		§ 8.3.1. – Specifying circumstances in which individual metering will be required
	Original Sheet No. 26		§ 8.16. – Added Customer's Responsibility to Cooperate with the Company
			§ 9. – Added instructions and contact number for gas leaks
			§ 10.1. – Added requirement for customer to furnish drivable surfaces for Company equipment to access sites
	Original Sheet Nos. 26 to 28		Updated Discontinuance of Service language to reflect N.J.A.C. 14:3-3A
Clauses			
Weather Normalization Charge	Original Sheet Nos. 45 to 47		Removed Charge as it is replaced by Conservation Incentive Program
Distribution Adjustment Charge	Original Sheet No. 52		Added the Distribution Adjustment Charge
Supply			
BGSS-F	Original Sheet No. 55		Removed language "For Rate Schedule CSG"
BGSS-I	Original Sheet No. 56		Removed language "For Rate Schedule CSG"
Emergency Sales Service	Original Sheet No. 58		Removed language "For Rate Schedule CSG"
Infrastructure Improvement Program Charges (Continued)	Original Sheet No. 61		Made formatting consistent among rate schedules
			Removed BGSS-RSG as it is impacted by multiple other factors
Delivery			
Rate Schedule RSG	Original Sheet No. 66		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
Rate Schedule GSG	Original Sheet No. 73		Added inclusion of the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
Rate Schedule LVG	Original Sheet No. 80		Added the Distribution Adjustment Charge to applicable clauses
			Corrected language regarding bundling of CIP rate for billing
Rate Schedule SLG	Original Sheet No. 88		Added the Distribution Adjustment Charge to applicable clauses
Rate Schedule TSG-F	Original Sheet No. 94		Added the Distribution Adjustment Charge to applicable clauses

Item	Sheet No.		Description
Rate Schedule TSG-NF	Original Sheet No. 99		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 100		Added language limiting customers taking Basic Gas Supply Service to a maximum of 2,000 therms per hour
	Original Sheet No. 102		Added requirement for customers switching to firm service to remain on firm service for one year
Rate Schedule CIG	Original Sheet No. 107		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 109		Added requirement for customers switching to firm service to remain on firm service for one year
	Original Sheet No. 110		Defined Commodity Charge when gas is supplied under Extended Gas Service
	Original Sheet No. 111		Removed “facsimile machine” as it is no longer used and clarified that communications would be conducted electronically
Rate Schedule CSG	Original Sheet No. 112B		Added the Distribution Adjustment Charge to applicable clauses
	Original Sheet No. 112C		Added language to clarify that the Minimum Annual Distribution Charge applies to both Economically Viable Bypass customers and Other Consideration customers
	Original Sheet No. 112E		Removed “telegram” as it is no longer used and clarified that communications would be conducted electronically
	Original Sheet No. 112F		Removed Rate Schedule CSG Periodic Update
Third Party Supplier Requirements			
Nomination Procedures	Original Sheet No. 115		§ 4.2. Added definition of a “Gas Day” and additional language to TPS Nomination Requirements
	Original Sheet Nos. 115 to 116		Removed § 4.3. TPS Nomination Requirements for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater
Credit Requirements	Original Sheet No. 116		Added Security obligations for Third Party Suppliers
	Original Sheet No. 117		Changed “facsimile” to “electronic”
Imbalance Cash-Out Procedures	Original Sheet No. 118		§ 6.1.3. Changed “Under deliveries” to “Balancing” and specified the price reference during critical periods
	Original Sheet No. 120		Specified price reference during critical periods
	Original Sheet No. 121		§ 6.3.3. Added language addressing imbalance; § 6.3.4. Specified price reference during critical periods
	Original Sheet No. 122		§ 6.3.6. Deleted Pooling language as it is not commonly used now
			§ 6.4. Added language to Cash-out Billing and Payment
Force Majeure	Original Sheet Nos. 122 to 123		Revised language describing applicable scenarios

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 1**

TARIFF

FOR

GAS SERVICE

Applicable in

Territory served as shown on

Sheet Nos. 3 through 6 of this Tariff

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL OFFICES

80 PARK PLAZA

NEWARK, NEW JERSEY 07102

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 2**

TABLE OF CONTENTS

Title Page ..... Sheet No. 1
Table of Contents ..... Sheet No. 2
Territory Served ..... Sheet Nos. 3 to 6, inclusive
Standard Terms and Conditions ..... Sheet Nos. 7 to 36, inclusive
Societal Benefits Charge ..... Sheet Nos. 41 and 42
Margin Adjustment Charge ..... Sheet No. 43
Green Programs Recovery Charge ..... Sheet No. 44
~~Weather Normalization Charge ..... Sheet Nos. 45 to 47, inclusive~~
Conservation Incentive Program ..... Sheet Nos. 48 to 48C, inclusive
Tax Adjustment Credit ..... Sheet No. 51
Distribution Adjustment Charge ..... Sheet No. 52
Basic Gas Supply Service
Commodity Charges Applicable to Rate Schedule RSG ..... Sheet No. 54
Commodity Charges Applicable to Rate Schedules GSG, LVG, SLG and CSG ..... Sheet No. 55
Commodity Charge Applicable to Rate Schedules TSG-NF and CSG ..... Sheet No. 56
Commodity Charge Applicable to Rate Schedule CIG ..... Sheet No. 57
Emergency Sales Service Charge Applicable to Rate Schedules
RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG ..... Sheet No. 58
Commodity Charge Applicable to Rate Schedule RSG Off-Peak Use ..... Sheet No. 59
Infrastructure Improvement Program Charges ..... Sheet Nos. 60 and 61

Delivery Rate Schedules as listed below:

	Rate Schedule	Sheet Nos.
Residential Service	RSG	65-69
General Service	GSG	72-77
Large Volume Service	LVG	79-84
Street Lighting Service	SLG	87-90
Firm Transportation Gas Service	TSG-F	93-96
Non-Firm Transportation Gas Service	TSG-NF	99-103
Cogeneration Interruptible Service	CIG	107-111
Contract Service	CSG	112-112F

Third Party Supplier Requirements 114-123

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 3**

TERRITORY SERVED

BERGEN COUNTY

Allendale, Borough of
Alpine, Borough of
Bergenfield, Borough of
Bogota, Borough of
Carlstadt, Borough of
Cliffside Park, Borough of
Closter, Borough of
Cresskill, Borough of
Demarest, Borough of
Dumont, Borough of
East Rutherford, Borough of
Edgewater, Borough of
Elmwood Park, Borough of
Emerson, Borough of
Englewood, City of
Englewood Cliffs, Borough of
Fair Lawn, Borough of
Fairview, Borough of
Fort Lee, Borough of
Franklin Lakes, Borough of
Garfield, City of
Glen Rock, Borough of
Hackensack, City of
Harrington Park, Borough of
Hasbrouck Heights, Borough of
Haworth, Borough of
Hillsdale, Borough of
Ho-Ho-Kus, Borough of
Leonia, Borough of
Little Ferry, Borough of
Lodi, Borough of
Lyndhurst, Township of
Mahwah, Township of
Maywood, Borough of
Midland Park, Borough of
Montvale, Borough of
Moonachie, Borough of
New Milford, Borough of
North Arlington, Borough of
Northvale, Borough of
Norwood, Borough of
Oakland, Borough of
Old Tappan, Borough of
Oradell, Borough of
Palisades Park, Borough of
Paramus, Borough of
Park Ridge, Borough of
Ramsey, Borough of
Ridgefield, Borough of
Ridgefield Park, Village of
Ridgewood, Village of
River Edge, Borough of
River Vale, Township of
Rochelle Park, Township of
Rockleigh, Borough of
Rutherford, Borough of
Saddle Brook, Township of
Saddle River, Borough of
South Hackensack, Township of
Teaneck, Township of
Tenafly, Borough of
Teterboro, Borough of
Upper Saddle River, Borough of
Waldwick, Borough of
Wallington, Borough of
Washington, Township of
Westwood, Borough of
Woodcliff Lake, Borough of
Wood-Ridge, Borough of
Wyckoff, Township of

BURLINGTON COUNTY

Beverly, City of
Bordentown, City of
Bordentown, Township of
Burlington, City of
Burlington, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 4**

TERRITORY SERVED
(Continued)

BURLINGTON COUNTY (continued)

Chesterfield, Township of
Cinnaminson, Township of
Delanco, Township of
Delran, Township of
Eastampton, Township of
Edgewater Park, Township of
Evesham, Township of
Fieldsboro, Borough of
Florence, Township of
Hainesport, Township of
Lumberton, Township of
Mansfield, Township of
Maple Shade, Township of
Medford, Township of
Moorestown, Township of
Mount Holly, Township of
Mount Laurel, Township of
New Hanover, Township of
North Hanover, Township of
Palmyra, Borough of
Pemberton, Borough of
Pemberton, Township of
Riverside, Township of
Riverton, Borough of
Southampton, Township of
Springfield, Township of
Westampton, Township of
Willingboro, Township of
Woodland, Township of
Wrightstown, Borough of

CAMDEN COUNTY

Audubon, Borough of
Audubon Park, Borough of
Barrington, Borough of
Bellmawr, Borough of
Brooklawn Borough of
Camden, City of
Cherry Hill, Township of
Collingswood, Borough of
Gloucester, City of
Haddon, Township of
Haddonfield, Borough of
Haddon Heights, Borough of
Lawnside, Borough of
Merchantville, Borough of
Mount Ephraim, Borough of
Oaklyn, Borough of
Pennsauken, Township of
Tavistock, Borough of
Woodlynne, Borough of

ESSEX COUNTY

Belleville, Town of
Bloomfield, Township of
Caldwell, Borough of
Cedar Grove, Township of
East Orange, City of
Essex Fells, Borough of
Fairfield, Township of
Glen Ridge, Borough of
Irvington, Township of
Livingston, Township of
Maplewood, Township of
Millburn, Township of
Montclair, Township of
Newark, City of
North Caldwell, Borough of
Nutley, Township of
Orange, City of
Roseland, Borough of
South Orange Village, Township of
Verona, Township of
West Caldwell, Township of
West Orange, Township of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 5**

TERRITORY SERVED
(Continued)

GLOUCESTER COUNTY

Deptford, Township of
National Park, Borough of
West Deptford, Township of
Westville, Borough of
Woodbury, City of

HUDSON COUNTY

Bayonne, City of
East Newark, Borough of
Guttenberg, Town of
Harrison, Town of
Hoboken, City of
Jersey City, City of
Kearny, Town of
North Bergen, Township of
Secaucus, Town of
Union City, City of
Weehawken, Township of
West New York, Town of

HUNTERDON COUNTY

East Amwell, Township of
Readington, Township of
Tewksbury, Township of

MERCER COUNTY

East Windsor, Township of
Ewing, Township of
Hamilton, Township of
Hightstown, Borough of
Lawrence, Township of
Princeton, Borough of
Princeton, Township of
Robbinsville, Township of
Trenton, City of
West Windsor, Township of

MIDDLESEX COUNTY

Cranbury, Township of
Dunellen, Borough of
East Brunswick, Township of
Edison, Township of
Helmetta, Borough of
Highland Park, Borough of
Jamesburg, Borough of
Middlesex, Borough of
Milltown, Borough of
Monroe, Township of
New Brunswick, City of
North Brunswick, Township of
Old Bridge, Township of
Piscataway, Township of
Plainsboro, Township of
Sayreville, Borough of
South Amboy, City of
South Brunswick, Township of
South Plainfield, Borough of
South River, Borough of
Spotswood, Borough of

MONMOUTH COUNTY

Allentown, Borough of
Millstone, Township of
Roosevelt, Borough of
Upper Freehold, Township of

MORRIS COUNTY

Butler, Borough of
Chatham, Borough of
Chatham, Township of
Chester, Borough of
Chester, Township of
Denville, Township of
East Hanover, Township of
Florham Park, Borough of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 6**

TERRITORY SERVED
(Continued)

MORRIS COUNTY (continued)

Hanover, Township of
Harding, Township of
Jefferson, Township of
Kinnelon, Borough of
Long Hill, Township of
Madison, Borough of
Mendham, Borough of
Mendham, Township of
Morris, Township of
Morris Plains, Borough of
Morristown, Town of
Parsippany-Troy Hills, Township of
Pequannock, Township of
Randolph, Township of
Riverdale, Borough of

OCEAN COUNTY

Plumsted, Township of

PASSAIC COUNTY

Bloomingdale, Borough of
Clifton, City of
Haledon, Borough of
Hawthorne, Borough of
Little Falls, Township of
North Haledon, Borough of
Passaic, City of
Paterson, City of
Pompton Lakes, Borough of
Prospect Park, Borough of
Ringwood, Borough of
Totowa, Borough of
Wanaque, Borough of
Wayne, Township of
West Milford, Township of
Woodland Park, Borough of

SOMERSET COUNTY

Bedminster, Township of
Bernards, Township of
Bernardsville, Borough of
Bound Brook, Borough of
Branchburg, Township of
Bridgewater, Township of
Far Hills, Borough of
Franklin, Township of
Green Brook, Township of
Hillsborough, Township of
Manville, Borough of
Millstone, Borough of
Montgomery, Township of
North Plainfield, Borough of
Peapack-Gladstone, Borough of
Raritan, Borough of
Rocky Hill, Borough of
Somerville, Borough of
South Bound Brook, Borough of
Warren, Township of
Watchung, Borough of

UNION COUNTY

Berkeley Heights, Township of
New Providence, Borough of
Plainfield, City of
Springfield, Township of
Summit, City of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 7**

STANDARD TERMS AND CONDITIONS - INDEX

		Sheet No.
1.	**General**	**9**
2.	**Obtaining Service**	**9**
	2.1. Application	9
	2.2. Initial Selection of Rate Schedule	9
	2.3. Deposit and Guarantee	10
	2.4. Permits	11
	2.5. Service Connections	11
	2.6. Temporary Service	11
3.	**Charges for Service**	**11**
	3.1. General	11
	3.2. Definitions	11
	3.3. Removal of Public Service Facilities	12
	3.4. Temporary Service	13
	3.5. Provision of Service	13
	3.6. Extensions-General Provisions	14
	3.7. Charges for Extensions	14
	3.8. Charges for Increased Load	17
4.	**Characteristics of Service**	**18**
	4.1. Standard Service Supply	18
	4.2. Heat Measurement and Billing Units	18
	4.3. Standard Pressure	18
5.	**Service Connections**	**18**
	5.1. General	18
	5.2. Change in Location of Existing Service Pipe	18
6.	**Meters and Associated Equipment**	**18**
	6.1. General	18
	6.2. Seals	19
	6.3. Protection of Meter and Service Equipment	19
	6.4. Public Service to Turn on Gas	19
	6.5. Change in Location of Meters and Associated Equipment	19
	6.6. Tampering	19
7.	**Customer's Installation**	**20**
	7.1. General	20
	7.2. Piping	20
	7.3. Gas Equipment and Appliances	20
	7.4. Back Pressure and Suction	20
	7.5. Maintenance of Customer's Installation	21
	7.6. Appliance Adjustments	21
	7.7. Adequacy and Safety of Installation	21
	7.8. Liability for Customer's Installation	21
8.	**Meter Reading and Billing**	**21**
	8.1. Measurement of Gas Used	21
	8.2. Correction for Pressure	22
	8.3. Metering on Customer's Premises	22
	8.4. Testing of Meters	23
	8.5. Metering Options	23
	8.6. Billing Adjustments	24
	8.7. Meter Reading and Billing Period	24
	8.8. Proration of Monthly Charges	24
	8.9. Averaged Bills	24
	8.10. Budget Plan (Equal Payment Plan)	25
	8.11. Billing of Charges in Tariff	25
	8.12. Payment of Bills	25
	8.13. Late Payment Charge	25
	8.14. Returned Check Charge	26
	8.15. Field Collection Charge	26
9.	**Leakage**	**26**
10.	**Access to Customer's Premises**	**26**
11.	**Discontinuance of Service**	**26**
	11.1. By Public Service	26
	11.2. At Customer's Request	28
12.	**Reconnection Charge**	**29**
13.	**Service Limitations**	**29**
	13.1. Continuity of Service	29
	13.2. Emergencies	29
	13.3. Unusual Conditions	29
14.	**Third Party Supplier Service Provisions**	**29**
	14.1. Third Party Supplier Gas Supply	29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 8**

STANDARD TERMS AND CONDITIONS – INDEX
(Continued)

		Sheet No.
	14.2. Enrollment	29
	14.3. Selection or Change of Third Party Supplier	30
	14.4. Return to Public Service Basic Gas Supply Service Default Service	30
	14.5. Emergency Sales Service	31
	14.6. Customer Billing Process	32
	14.7. Third Party Supplier's Termination of Customer's Gas Supply	33
	14.8. Continuity of Service	33
	14.9. Regulatory Requirements	33
	14.10. Delivery Liability	33
	14.11. Delivery Control and Possession	33
15.	**New Jersey Authorized Taxes**	**33**
	15.1. New Jersey Sales and Use Tax	33
	15.2. New Jersey Corporation Business Tax	34
16.	**New Jersey Authorized Exemptions**	**35**
	16.1. Exemptions due to LCAPP Legislation	35
17.	**Termination, Change, or Modification of Provisions of Tariff**	**36**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 9**

STANDARD TERMS AND CONDITIONS

1. GENERAL

These Standard Terms and Conditions, filed as part of the Gas Tariff of Public Service Electric and Gas Company, hereinafter referred to as "Public Service", set forth the terms and conditions under which gas service will be supplied and govern all classes of service to the extent applicable, and are made a part of all agreements for the supply of gas service unless specifically modified in a particular rate schedule.

No representative of Public Service has authority to modify any provision contained in this Tariff or to bind Public Service by any promise or representation contrary thereto.

Public Service will construct, own, and maintain distribution mains and services located on land, streets, highways, rights of way acquired by Public Service, and on private property, used or usable as part of the distribution system of Public Service. Payment of monthly charges, or a deposit or a contribution shall not give the customer, Applicant or depositor any interest in the facilities, the ownership being vested exclusively in Public Service.

Publications set forth by title in sections of these Standard Terms and Conditions are incorporated in this Tariff by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, ~~Third Floor, Suite 314,~~ P.O. Box 350, Trenton, New Jersey, 08625-0350 or 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1. **Application:** An application for service may be made at any of the Customer Service Centers of Public Service in person, ~~by mail,~~or by telephone, by the Company's website at www.pseg.com, ~~or by facsimile transmission~~ or electronic mail, where available. Forms for application for service, when required, together with terms and conditions and rate schedules, will be furnished upon request. All customers shall be given a copy of the Customer Bill of Rights, effective at the time of service initiation. Customer shall state, at the time of making application for service, the conditions under which service will be required and customer may be required to sign an agreement or other form then in use by Public Service covering special circumstances for the supply of gas service. Data requested from customers may include proof of identification as well as copies of leases, deeds and corporate charters in accordance with N.J.A.C. 14:3-3.2 (e) and (f). Such information shall be considered confidential.

Public Service may reject applications for service where such service is not available or where such service might affect the supply of gas to other customers, or for failure of customer to agree to comply with any of these Standard Terms and Conditions.

See also Section 13 Service Limitations, of these Standard Terms and Conditions.

2.2. **Initial Selection of Rate Schedule:** Public Service will assist in the selection of the available rate schedule which is most favorable from the standpoint of the customer. Any advice given by Public Service will necessarily be based on customer's written statements detailing the customer's proposed operating conditions.

Customers may, upon written notice to Public Service within three months after service has begun, elect to change and to receive service under any other available rate schedule. Public Service will furnish service to and bill the customer under the rate schedule so selected from the date of last scheduled meter reading, but no further change will be allowed during the next twelve months.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 10**

STANDARD TERMS AND CONDITIONS
(Continued)

2.2.1. Change of Rate Schedule: Subsequent to initial selection of a rate schedule, customer shall notify Public Service in writing of any change in the customer's use of service which might affect the selection of a rate schedule or provision within a rate schedule. Any change in schedule or provision shall be applicable, if permitted, to the next regular billing subsequent to such notification.

2.3. Deposit and Guarantee: Public Service may require a reasonable deposit as a condition of supplying service, in accordance with the provisions as set forth in Board of Public Utility regulations.

A deposit may be required from a customer equal to the average monthly charge for a twelve-month period and one month's average bill. A customer taking service for a period of less than thirty days may be required to deposit an amount equal to the estimated bill for such temporary period.

Upon closing any account, the balance of any deposit remaining after the closing bill for service has been settled, shall be returned promptly to the customer with any interest due. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one full billing cycle.

Public Service shall review a residential customer's account at least once every year and a non-residential customer's account at least once every 2 years. If such review indicates that the customer has established credit satisfactory to Public Service, then the outstanding deposit shall be refunded to the customer. The customer has the option of having the deposit refund applied to the account in the form of a credit or of having the deposit refunded by separate check in a period not to exceed one billing cycle.

In accordance with N.J.A.C. 14:3-3.5(d), simple interest at a rate equal to the average yields on new six-month Treasury Bills for the twelve month period ending each September 30 shall be paid by Public Service on all deposits held by it after notification by the BPU of the new effective rate. Said rate shall be determined by the Board of Public Utilities ("Board"), and shall become effective on January 1 of the following year.

For residential customers, interest payments shall be made at least once during each 12-month period in which a deposit is held. Residential customers shall have the option of a credit to the customer's account or a separate check.

A deposit is not a payment or part payment of any bill for service, except that on discontinuance of service Public Service may apply said deposit against unpaid bills for service, and only the remaining balance of the deposit will be refunded. Public Service shall promptly read the meters and ascertain that the obligations of the customer have been fully performed before being required to return any deposit. To have service resumed, a deposit may be required, but the deposit shall not be required prior to restoration of service. Public Service shall bill the customer for the deposit and allow at least 15 days after the billing for payment of deposit, or make other reasonable arrangements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 11**

STANDARD TERMS AND CONDITIONS
(Continued)

2.4. **Permits**: Public Service, where necessary, will make application for any street opening permits for installing its gas facilities necessary to provide new or upgraded service to a customer and shall not be required to furnish service until after such permits are granted. The Applicant may be required to pay the municipal charge, if any, for permission to open the street. The Applicant shall obtain and present to Public Service, for recording or for registration, all instruments providing for easements or rights of way, and all permits (except street opening permits), consents, and certificates necessary for the introduction of service.

2.5. **Service Connections:** The customer may be required to make a contribution toward the cost of installing a service connection as set forth in Section 5 of these Standard Terms and Conditions.

2.6. **Temporary Service:** Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to Public Service the cost of the facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the revenue from Service Charges, Distribution Charges and Demand Charges received by Public Service during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

3. CHARGES FOR SERVICE

3.1. **General:** Charges for gas usage are set forth in the rate schedules included elsewhere in this Tariff. In addition to the charges for gas usage, Public Service may require additional monthly charges, up-front contributions or deposits (including the gross-up for income tax effects) from an Applicant for providing Temporary Services, for certain Standard and Atypical Conditions, or for an Extension.

3.2. **Definitions:** The following are defined terms as used in this Tariff:

a) Applicant is the individual or entity, who may or may not be the ultimate customer, requesting new, additional, temporary, or upgraded gas service from Public Service.

b) Applicant For An Extension is an Applicant where Public Service has determined that an Extension is necessary to provide service.

c) N.J.A.C. is the New Jersey Administrative Code.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 12**

STANDARD TERMS AND CONDITIONS
(Continued)

d) Distribution Revenue as used in this Section 3 means the total revenue, plus related New Jersey Sales and Use Tax (SUT), charged a customer by Public Service, minus Basic Gas Supply Service charges including SUT, assessed in accordance with this Tariff for Gas Service. For Rate CIG the Basic Gas Supply Service Charges is the Estimated Average Commodity Cost plus Losses and applicable SUT.

e) Temporary Service is where service is provided through an installation for a limited period and such installation is not permanent in nature.

f) An Extension means the construction or installation of plant and/or facilities by Public Service used to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. An Extension includes all Public Service plant and/or facilities used for gas transmission (non-FERC jurisdictional) and/or distribution, whether located on a public street or right of way, or on private property or private right of way, and includes the pipe, rights of way, land, valves, site restoration, regulators and metering equipment and other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An Extension does not include equipment solely used for administrative purposes, such as office equipment used for administering a billing system.

An Extension begins at the existing Public Service infrastructure and ends at the meter and includes the meter. The new plant and/or facilities installed constituting an Extension must be nominally physically continuous from the beginning to the end of the Extension.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an Extension where existing Public Service facilities are upgraded or replaced due to an Applicant's new or additional gas load being greater than 50% of the total design capacity of the pre-existing facilities.

g) Cost means, with respect to the cost of construction of an Extension, actual and/or site-specific unitized expenses incurred by Public Service for materials and labor, including both internal and external labor, employed in the actual design, purchase, construction, and/or installation of the Extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure as well as tax gross ups, inclusive of the applicable bonus depreciation credits. Costs related to plant and/or facilities installed to serve increased load from an existing customer are determined on a similar basis.

3.3. Removal of Public Service Facilities: There is normally no charge for the permanent removal of above ground Public Service facilities or the abandonment in place of underground Public Service facilities where an easement for such facilities does not exist. Where an easement exists, and when approved by Public Service, and unless preempted by statute, the requesting party shall be responsible for all costs related to the removal or abandonment of requested facilities and if necessary, the installation of all new facilities necessary to provide the same level of service to all other customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 13**

STANDARD TERMS AND CONDITIONS
(Continued)

3.4. **Temporary Service**: Where Public Service provides Temporary Service, the customer will be required to pay to Public Service the cost of the installation and removal of facilities required to furnish service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service, a Temporary Service installation shall be eligible for refunds. Excluding the first two annual service periods, refunds equal to 10% of the Distribution Revenue received by Public Service during each annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation and removal cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will not be supplied under Rate Schedule SLG.

3.5. **Provision of Service:** Gas service shall be supplied in accordance with these Standard Terms and Conditions and the applicable rate schedule and shall be based upon customer's anticipated load and upon plant facilities that are sufficient for safe, proper, and adequate service based upon Public Service's design standards and reliability criteria. Both the Applicant's anticipated load and sufficient plant facilities will be as determined by Public Service.

3.5.1. **Standard Conditions:** Underground construction is the standard for all gas mains and services. Metering and regulating facilities are normally located above ground outside of buildings, unless required by Public Service operating conditions in which case they will be located inside.

3.5.2. **Atypical Conditions:** When special facilities are required due to conditions beyond the control of Public Service, or are requested by the Applicant and approved by Public Service, or are required due to local ordinance, the added cost of such special facilities, grossed up for income tax effects, shall be paid by the Applicant as a non-refundable contribution.

Public Service may require agreements for a longer term than specified in the rate schedule, may require contributions toward the investment, and may establish such Minimum Charges and Facilities Charges as may be equitable under the circumstances involved where: (1) large or special investment is necessary for the supply of service; (2) capacity required to serve Rate Schedules GSG or LVG customer's weather-sensitive or dual-fueled equipment is out of proportion to the use of gas service for occasional, intermittent, or low load factor purposes, or is for short durations. The assessment of any Minimum Charges will be based upon a minimum use requirement of 850 therms per year for each therm of applicable connected load. To the extent that total annual therm usage is less than 850 therms per therm of connected load, any deficiency will be assessed a Minimum Charge of $0.25 ($0.27 including SUT) per therm.

Unless there is a material change in the provision of service, once charges are established for a premises pursuant to this Section 3.5.2, they shall be used for all subsequent customers at that premises requesting such similar service, regardless of any lapse in the provision of such similar service characteristics to that premises.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 14**

STANDARD TERMS AND CONDITIONS
(Continued)

3.6. Extensions – General Provisions: Where it is necessary for Public Service to construct an Extension to serve the requirements of an Applicant, Public Service may require a deposit or contribution from the customer to cover all or part of the cost of the Extension, which is required to be paid to Public Service prior to any work being performed. The costs will be estimated based upon normal conditions, and may be increased if severe conditions, such as excessive rock or other unknown conditions, are found during excavation.

3.7. Charges for Extensions: Applicants requesting service may be charged a deposit for service. Such deposit will be determined by Public Service by comparing the estimated Distribution Revenue to the applicable costs of the Extension. The detailed calculations of such deposits, if any, are contained in the remainder of Section 3.7 of these Standard Terms and Conditions.

3.7.1. Individual Residential Customer: Where application for service is made by an Applicant for individual residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

b) In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

c) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

d) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 15**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.2. Multi-unit Developments: Where application for service is made for gas service to a multi-unit residential or multi-unit non-residential development, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions, such result grossed up for income tax effects.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit, requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As each unit is connected, as determined by the setting and activation of the Public Service gas meter, there shall be returned to the Applicant an amount equal to ten times the estimated annual Distribution Revenue from that unit multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if for all customers receiving service for the entire prior one year period the actual annual Distribution Revenue exceeds the greater of either: (1) the estimated annual Distribution Revenue, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 16**

STANDARD TERMS AND CONDITIONS
(Continued)

3.7.3. Individual Commercial and Industrial Customers: Where application for service is made for individual non-residential use, and the service requested is not for a limited period of less than ten (10) years, the following shall apply:

a) Excess cost for an Applicant is defined as the total cost of the Extension less any contribution required for Atypical Conditions less ten times the estimated average annual Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

Any excess cost shall be deposited and remain with Public Service with interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less, or where ten times the estimated annual Distribution Revenue is greater than the excess costs and the excess cost is less than $20,000.00.

b) As the Public Service gas meter is set, there shall be returned to the Applicant an amount equal to ten (10) times the estimated average annual Distribution revenue multiplied by the tax gross up factor used when the deposit was taken.

c) In each annual period from the date of deposit, if the actual Distribution Revenue from the customer exceeds the greater of: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit, or (2) the highest actual Distribution Revenue from any prior year; there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

d) As additional customers not originally anticipated are supplied from this Extension and Public Service still holds at least some part of the deposit from the original Applicant, a reduction may be made to such remaining deposit. The cost of the Extension or cost for Increased Load for any such additional customer will be first compared to the estimated additional Distribution Revenue as detailed in the appropriate paragraph of this Section 3. Once any deposit requirement has been satisfied, any remaining Distribution Revenue credit will be applied toward the original customer's remaining deposit in an amount equal to ten times such excess Distribution Revenue multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the original deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 17**

STANDARD TERMS AND CONDITIONS
(Continued)

3.8. Charges for Increased Load: When it is necessary for Public Service to construct, upgrade, or install facilities necessary to service the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 3.2 (f) of these Standard Terms and Conditions, the following shall apply:

a) Public Service may require a deposit from the customer to cover all or part of the investment necessary to supply service. Any such deposit will be calculated by comparing the estimated annual increase in Distribution Revenue as determined by Public Service to the total cost of the applicable work to determine if excess costs exist.

b) Excess cost is defined as the total cost of the applicable work less any contribution required for Atypical Conditions less the ten times the estimated average annual increase in Distribution Revenue, such result grossed up for income tax effects. The excess cost shall not be less than zero in any case.

c) Any excess cost shall be deposited and remain with Public Service without interest. Public Service will waive the deposit requirement where the excess cost is $3,000.00 or less.

d) In each annual period from the date of connection of such additional load, if the actual increase in Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual increase in Distribution Revenue used as the basis for the initial deposit, or (2) the highest increase in actual Distribution Revenue from any prior year, there shall be returned to the Applicant an additional amount, equal to ten times such excess multiplied by the tax gross up factor used when the deposit was taken.

e) In no event shall more than the original deposit be returned to the Applicant nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 18**

STANDARD TERMS AND CONDITIONS
(Continued)

4. CHARACTERISTICS OF SERVICE

4.1. **Standard Service Supply:** Public Service may commingle gas supplies from several sources. All gas delivered to any customer may be a mixture of gas manufactured or derived from natural sources, altered to remove impurities and to add desirable constituents. The heat content of delivered gas may vary between 950 and 1,150 Btu per cubic foot. The character of the gas will be of a nature which will allow an atmospheric burner to operate without repeated adjustment.

4.2. **Heat Measurement and Billing Units:** For billing purposes, the customer's gas use in cubic feet will be converted to therms, using the actual weighted average heating value, on a dry basis, of the gas distributed in the second preceding calendar month, where a therm is a unit of heat energy equivalent to 100,000 British thermal units (Btu). Metered usage in cubic feet at standard pressure will be corrected to atmospheric pressure by application of a 1.012 multiplier. Metered usage at higher than standard pressure will be corrected to atmospheric pressure by application of appropriate multipliers.

4.3. **Standard Pressure:** The standard pressure supplied at the meter outlet will be within the range of 4 to 7 inches water column pressure.

5. SERVICE CONNECTIONS

5.1. **General:** The Applicant shall consult Public Service as to the exact point at which the meter set will be located and connection to customer piping will be made before installing interior gas piping or starting any other work dependent upon the location of the service pipe.

Public Service will determine the location of the service pipe depending upon existing facilities in the street and other practical considerations.

Gas service will be supplied to each building or premises through a single service pipe except where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or volume of the customer's requirements, make it desirable to install more than one service pipe.

5.2. **Change in Location of Existing Service Pipe:** Any change requested by the customer in the location of the existing service pipe, if approved by Public Service, will be made at the expense of the customer. A request to install facilities for the same building within 12 months of the removal of similar facilities may be considered a relocation of the existing facilities if the load served is similar or lower and the building served is essentially the same.

6. METERS AND ASSOCIATED EQUIPMENT

6.1. **General**: A single meter will be furnished and installed by Public Service for each separately billed rate schedule under which a customer receives service. Public Service shall be consulted regarding meter locations. Meter installations shall be in conformance

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 19**

STANDARD TERMS AND CONDITIONS
(Continued)

with the standards of the fuel gas subcode of the "Uniform Construction Code" and the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. Where permitted, the meter shall be located outside. If the meter is not located outside solely due to the request of the customer, Public Service reserves the right to install remote metering equipment at the customer's expense. See Section 8.5 of these Standard Terms and Conditions. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2.

When requested by a customer, remote meter reading equipment may be installed, if feasible, at the expense of the customer. The payment shall not give the customer any interest in the equipment thus installed, the ownership being vested exclusively in Public Service.

Additional meters will be installed only where, in the judgment of Public Service, its economic considerations; conditions on its distribution system; improvement of service conditions; or the volume of the customer's requirements, make it desirable to install such additional meters.

6.2. **Seals:** Public Service may seal or lock any meters or enclosures containing meters and associated metering equipment. No person except a duly authorized employee of Public Service shall break or remove a Public Service seal or lock.

6.3. **Protection of Meter and Service Equipment:** Customer shall furnish and maintain a suitable space for the meter and associated equipment. Such space shall be as near as practicable to the point of entrance of the gas service pipe, adequately ventilated, dry (inside installation only) and free from corrosive vapors, not subject to extreme temperatures, readily accessible to duly authorized employees or agents of Public Service and shall otherwise conform to the standards of the fuel gas subcode of the "Uniform Construction Code" and to the "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request. The gas meter cannot be located behind fences or gates unless no other practical location can be identified. Customer shall not tamper with or remove meters or other equipment, nor permit access thereto except by duly authorized employees or agents of Public Service. In case of loss or damage to the property of Public Service from the act or negligence of the customer or the customer's agents or servants, or of failure to return equipment supplied by Public Service, customer shall pay to Public Service the amount of such loss or damage to the property. All equipment furnished at the expense of Public Service shall remain its property and may be replaced whenever deemed necessary and may be removed by it at any reasonable time after the discontinuance of service. In the case of defective service, the customer shall not interfere or tamper with the apparatus belonging to Public Service but shall immediately notify Public Service to have the defects remedied.

6.4. **Public Service to Turn on Gas:** No person other than a duly authorized employee or agent of Public Service shall turn gas into any new system of piping or into any old system of piping from which the use of gas had been discontinued.

6.5. **Change in Location of Meters and Associated Equipment:** Any change requested by the customer in the existing location of meters and associated equipment, if approved by Public Service, will be made at the expense of the customer.

6.6. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the charges for such gas service under the applicable rate schedule including Basic Gas Supply Service default service, based

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 20**

STANDARD TERMS AND CONDITIONS
(Continued)

upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule including Basic Gas Supply Service default service but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.6.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

7. CUSTOMER'S INSTALLATION

7.1. **General:** No material change in the total input rating, or method of operation of customer's equipment shall be made without previous written notice to Public Service. For the purpose of this paragraph a material change in total input rating is defined as a change of 50,000 Btu per hour input or 10%, whichever is larger. A material change in method of operation is defined as a 50% change in the customer's total annual gas consumption.

7.2. **Piping:** Gas piping installed on the customer's premises must conform to all requirements of municipal or other properly constituted public authorities, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and to the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.3. **Gas Equipment and Appliances:** All gas equipment and appliances shall be certified to applicable U.S. standards by a nationally recognized testing laboratory, and marked with the appropriate certification approval. The manner of installation of all gas equipment and appliances shall be in accordance with all local construction codes, the most current edition of the standards of the fuel gas subcode of the "Uniform Construction Code", and the regulations set forth in "General Criteria for Installation of Gas Appliances and Gas Piping," issued by Public Service and available on request.

7.4. **Back Pressure and Suction:** When the nature of customer's gas fired equipment, gas compressors or gas piping configuration is such that it may cause back pressure or suction in the piping system, meters or other associated equipment of Public Service, suitable protective devices as defined by the standards of the fuel gas subcode of the "Uniform Construction Code", fittings, valves or check valves shall be furnished, installed and maintained by the customer, subject to the inspection and approval by Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 21**

STANDARD TERMS AND CONDITIONS
(Continued)

7.5. Maintenance of Customer's Installation: Customer's entire installation shall be maintained in the condition required by the municipal or other public authorities having jurisdiction and by Public Service.

7.6. Appliance Adjustments: Public Service will make, without additional charge, safety related adjustments to gas burners and certain associated equipment as determined by the Board to be necessary to the functioning of gas appliances in use on customer's premises. Other adjustments or repairs to such appliances may be made, or other services connected with the rendering of gas service may be performed, by Public Service at the customer's expense. Service procedures are detailed in "Servicing Equipment and Facilities on Customers' Premises," issued by Public Service and available on request.

7.7. Adequacy and Safety of Installation: Public Service shall not be required to supply gas service until the customer's installation shall have been approved by the authorities having jurisdiction. Public Service may withhold or discontinue its service whenever such installation or part thereof is deemed by Public Service to be unsafe, inadequate, or unsuitable for receiving service, or to interfere with or impair the continuity or quality of service to the customer or to others.

Public Service will assume no responsibility for the condition of customer's gas installation or for accidents, fires, or failures which may occur as the result of the condition of such gas installation.

Neither by inspection or nonrejection, nor in any other way, does Public Service give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structure, equipment, wires, pipes, appliances, or devices used by the customer.

7.8. Liability for Customer's Installation: Public Service will not be liable for damages or for injuries sustained by customers or others or by the equipment of customers or others by reason of the condition or character of customers' facilities or the equipment of others on customers' premises or by reason of the characteristics of the service that are in accord with Section 4.1 of these Standard Terms and Conditions. Public Service will not be liable for the use, care or handling of the gas service delivered to the customer after same passes beyond the point at which the service facilities of Public Service connect to the customers' facilities.

8. METER READING AND BILLING

8.1. Measurement of Gas Used: Public Service will select the type and make of metering equipment and may, from time to time, change or alter such equipment; its sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

Where service through more than one meter is permitted by Public Service as outlined under Section 6.1 of these Standard Terms and Conditions, the cubic-foot use registered by the individual meters will be combined for billing purposes. In all other instances, each meter shall be billed separately.

Bills will be based upon registration of Public Service meters except as otherwise provided for in this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 22**

STANDARD TERMS AND CONDITIONS
(Continued)

8.2. Correction for Pressure: In any case where, pursuant to Section 4.3, Public Service measures the gas delivered to a customer under pressure greater than that exerted by a column of water seven inches in height, the cubic feet of gas registered by the meter or meters of Public Service shall be subject to correction for billing purposes by the application of a proper correction factor.

8.3. Metering on Customer's Premises:

8.3.1. General: The service and supply of gas by Public Service for the use of owners, landlords, tenants, or occupants of newly constructed or renovated residential units~~buildings or premises~~ will be furnished to them as customers of Public Service through Public Service individual meters, except as noted below in Section 8.3.2.

The service and supply of gas by Public Service to owners, landlords, tenants, or occupants of industrial or commercial buildings or residential premises as noted below in section 8.3.2 may be further distributed to other users within such structures and such use and resultant charges, including reasonable administrative costs, apportioned to such users. However, such charges shall not exceed the amount that Public Service would charge if the tenant were served and billed directly by Public Service on the most appropriate rate schedule. In no event will a customer buying gas service from Public Service be permitted to resell it for a profit.

Where customer installs, or has installed a gas-fired pool heating device, service to such device must be limited to a separate line with a shutoff valve or a separate meter.

8.3.2. Sub-metering: The practice where a primary customer of Public Service or customer of record, through the use of direct metering devices, installed, operated and maintained at such customer's expense, monitors, evaluates, or measures their own gas consumption or the consumption of a tenant for accounting or conservations purposes.

Gas sub-meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a Public Service owned meter. Gas sub-meters provide the customer-of-record the means to apportion among the end users the cost of gas service being supplied through the Public Service owned meter.

Sub-metering will be permitted in new or existing buildings or premises where the basic characteristic of use is industrial or commercial. Sub-metering will not be permitted in new or existing buildings or premises where the basic characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing; or are eleemosynary in nature. In the case of dwelling units, all gas consuming devices must be metered through a single sub-meter.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 23**

STANDARD TERMS AND CONDITIONS
(Continued)

Sub-metering for the aforementioned purposes and applications shall not adversely affect the ability of Public Service to render service to any customer within the affected building or premises or any other customer. The customer shall contact Public Service prior to the installation of any sub-metering device to ascertain that it will not cause operating problems. The ownership of all sub-metering devices is that of the customer, along with all incidents in connection with said ownership, including accuracy of the equipment, meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of sub-metering devices shall be borne by the customer.

The customer shall be responsible for the accuracy of sub-metering equipment. In the event of a dispute involving such accuracy, the Public Service meter will be presumed correct, subject to test results.

8.4. **Testing of Meters:** At such times as Public Service may deem proper, or as the Board of Public Utilities may require, Public Service will test its meters in accordance with the standards and bases prescribed by the Board of Public Utilities.

Public Service shall, without charge, make a test of the accuracy of a meter(s) upon request of the customer, provided such customer does not make a request for test more frequently than once in 12 months. A report giving results of such tests shall be made to the customer, and a complete record of such tests shall be kept on file at the office of Public Service in conformance with the New Jersey Administrative Code.

8.5. **Metering Options:** The following optional metering services are available to customers and are subject to the following charges as indicated in the following subsections:

8.5.1. **Gas Data Pulses and Remotes:** Public Service will install and maintain the necessary equipment to supply data pulses for the customer's use, and remote metering equipment at the customer's request. Customers requesting these services are subject to a minimum term of one year:

Description	**Set-Up Charge – Data Pulses**		**Monthly Charge**
	Charges	Charges including SUT	
Residential Meter	$100.00	$ 106.63	$1.00
Large Diaphragm – Retrofit	$ 40.00	$ 42.65	$1.00
Large Diaphragm – Change			
Model 53 It	$100.00	$ 106.63	$2.00
Model 10 It	$130.00	$ 138.61	$2.00
Model 20 It	$130.00	$ 138.61	$2.00
Model 30 It	$340.00	$ 362.53	$3.00
Model 60 It	$650.00	$ 693.06	$3.00
Rotary without Instrument	$450.00	$ 479.81	$2.00
Rotary with Instrument	$100.00	$ 106.63	$2.00
Turbine	$100.00	$ 106.63	$2.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 24**

STANDARD TERMS AND CONDITIONS
(Continued)

8.5.2. Customer Usage Information: Where Public Service has an interval meter installed, twelve months of interval usage, where available, will be provided upon request of the customer. The historical interval data will be provided based upon the measurement interval of the installed meter, and will be sent to the customer in an electronic format. The cost per meter, per request is $40.00.

Where Public Service has an interval meter installed, Public Service will provide Internet access to customer historical usage data on a next-day basis for those customers who request such service. The charges for this service shall include a set up charge of $107.00 per meter, and a monthly charge of $17.00 per meter per month. Customer will be required to sign an Agreement for this service.

8.6. Billing Adjustments: Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2%, an adjustment of charges may be made in the case of meter tampering, non-register meters, or in circumstances in which a customer, other than RSG, should reasonably have known that the bill did not accurately reflect the usage. Billing adjustments shall be made in accordance with N.J.A.C. 14:3-4.6.

8.7. Meter Reading and Billing Period: All charges are stated on a monthly basis. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled meter readings. Meter reading schedules provide for reading meters, in accordance with their geographic location, as nearly as may be practicable every thirty days. Schedules are prepared in advance by Public Service and are available for inspection.

8.8. Proration of Monthly Charges: For all billings for service, including initial bills, final bills, and bills for periods other than twenty-five to thirty-six days inclusive, except for temporary service accounts and Rate Schedules CIG, TSG-F, TSG-NF, and CSG, the monthly charges will be prorated based on the number of days in the billing month. For temporary service accounts the minimum period for billing purposes shall be one month.

8.9. Averaged Bills: Where Public Service is unable to read the meter, Public Service may estimate the amount of gas supplied and submit an averaged bill, so marked, for customer's acceptance. Adjustments for averaged bills shall be made in Accordance with N.J.A.C. 14:3-7.2. Adjustment of such customer's averaged use to actual use will be made after an actual meter reading is obtained.

Public Service reserves the right to discontinue gas service when a meter reading is not obtained for eight (8) consecutive billing periods (monthly accounts), and after written notice is sent to a customer on the fifth and seventh months explaining that a meter reading must be obtained. Public Service will take all reasonable means to obtain a meter reading during normal working hours, evening hours or Saturdays before discontinuing service. After all reasonable means to obtain a meter reading have been exhausted, Public Service may discontinue service provided at least eight months have passed since the last meter reading was obtained, the Board of Public Utilities has been so notified and the customer has been properly notified by prior mailing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 25**

STANDARD TERMS AND CONDITIONS
(Continued)

8.10. Budget Plan (Equal Payment Plan): Customers billed under Rate Schedules RSG and GSG (where GSG gas service is used for residential purposes in buildings of four or fewer units), shall have the option of paying for their Public Service charges in equal, estimated monthly installments. Budget plans for residential accounts shall be made in accordance with N.J.A.C. 14:3-7.5. The total Public Service charges for a twelve month period will be averaged over twelve months and may be paid in twelve equal monthly installments. Adjustments will be made in the twelfth month if actual charges are more or less than the budget amounts billed. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

8.11. Billing of Charges in Tariff: Unless otherwise ordered by the Board of Public Utilities, the charges and the classification of service set forth in this Tariff or in amendments hereof shall apply to the first month's billing of service in the regular course on and after the effective date set forth in such Tariff covering the use of gas service subsequent to the scheduled meter reading date for the immediately preceding month.

8.12. Payment of Bills: At least 15 days' time for payment shall be allowed after sending a bill. Bills are payable at any Customer Service Center of Public Service, or by mail, or to any collector or collection agency duly authorized by Public Service. Whenever a residential customer advises Public Service that the customer wishes to discuss a deferred payment agreement because the customer is presently unable to pay a total outstanding bill and/or deposit, Public Service will make a good-faith effort to allow the customer the opportunity to enter into a fair and reasonable deferred payment agreement, which takes into consideration the customer's financial situation. A residential electric or gas customer is not required to pay, as a down payment, more than 25% of the total outstanding bill due at the time of the agreement. Such agreements which extend more than 2 months must be in writing and shall provide that a customer who is presently unable to pay an outstanding debt for Public Service services may make reasonable periodic payments until the debt is liquidated, while continuing payment of current bills. While a deferred payment agreement for each separate service need not be entered into more than once a year, Public Service may offer more than one such agreement in a year. If the customer defaults on any of the terms of the agreement, Public Service may discontinue service after providing the customer with a notice of discontinuance. If a customer's service has been terminated for non-payment of bills, and has met all requirements for restoration of service, Public Service may require a deposit, but not prior to service restoration. Instead, Public Service will bill payment of the deposit, or make other reasonable arrangements. The amount of the deposit required for restoration of service will be determined in accordance with N.J.A.C. 14:3-3.4.

In the case of a residential customer who receives more than one utility service from Public Service and has entered into a separate agreement for each separate service, default on one such agreement shall constitute grounds for discontinuance of only that service.

8.13. Late Payment Charge: A late payment charge at the rate of 1.416% per monthly billing period shall be applied to the accounts of customers taking service under all rate schedules contained herein except for Rate Schedule RSG. Service to a body politic will not be subject to a late payment charge. The charge will be applied to all amounts billed including accounts payable and unpaid finance charges applied to previous bills,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 26**

STANDARD TERMS AND CONDITIONS
(Continued)

and will not be applied sooner than 25 days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). The amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late payment charge rate. When payment is received by Public Service from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

8.14. Returned Check Charge: A $15.00 charge shall be applied to the accounts of customers who have checks to Public Service returned unhonored by the bank.

8.15. Field Collection Charge: A charge may be applied to the accounts of customers when it becomes necessary for Public Service to make a collection visit to the customer or premises. A charge of $30.00 may be applied to commercial and industrial accounts which include Rate Schedules: GSG, LVG, SLG, CIG, TSG-F, TSG-NF and CSG.

8.16. Customer's Responsibility to Cooperate with the Company: The charge provisions for extensions are predicated upon cooperation by the Customer in an effort to keep the Company's cost as low as possible. Additional costs resulting from the Customer's failure to cooperate, such as the paving of roads, parking areas or driveways prior to the installation of Company's facilities, shall be borne by the Customer.

9. LEAKAGE

Customer shall immediately give notice to Public Service at its office of any escape of gas in or about the customer's premises. If a leakage is suspected, immediately exit the building and move at least 350 feet away. Once the customer is at a safe distance, call PSE&G Emergency Service Line at 1-800-880-PSEG (7734) or 911 to report a potential gas leak. Customer will not be charged for reporting a potential gas leak.

10. ACCESS TO CUSTOMER'S PREMISES

Public Service shall have the right of reasonable and safe access to customer's premises, and to all property furnished by Public Service, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service, reading meters or inspecting, testing, or repairing its facilities used in connection with supplying the service, or for the removal of its property. The customer shall obtain, or cause to be obtained, all permits needed by Public Service for access to its facilities. Access to facilities of Public Service shall not be given except to authorized employees of Public Service or duly authorized governmental officials.

10.1. Drivable Surfaces: When a vehicle is needed to drive on customer's property to access Public Service facilities, the customer shall ensure that the path has a drivable surface that will prevent the vehicle from becoming disabled.

11. DISCONTINUANCE OF SERVICE

11.1. By Public Service: Public Service, upon ~~reasonable~~ notice, when it can be reasonably given, may suspend or curtail or discontinue service for the following reasons: (1) for the purpose of making permanent or temporary repairs, changes or improvements in any part of its system; (2) for compliance in good faith with any governmental order or directive notwithstanding such order or directive subsequently may be held to be invalid; (3) for any of the following acts or omissions on the part of the customer: (a) non-payment of a valid bill due for service furnished at a present or previous location~~. H~~, however, non-payment for business service shall not be a reason for discontinuance of ~~residence~~ residential service except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8; (b) tampering with any facility of Public Service; (c) fraudulent representation in relation to the use of service; (d) customer moving from the premises, unless the customer requests that service be continued; (e) providing service to others without approval of Public Service except as permitted under Section 8.3 Metering on Customer's Premises of these Standard Terms and Conditions; (f) failure to make or increase an advance payment or deposit as provided for in these Standard Terms and Conditions; (g) refusal to contract for service where such contract is required; (h) connecting and operating equipment in such manner as to produce disturbing effects on the service of Public Service or other customers; (i) failure of the customer to comply with any of these Standard Terms and Conditions; (j) where the condition of the customer's installation presents a hazard to life or property; or (k) failure of customer to repair any faulty facility of the customer; (4) for refusal of reasonable and safe access to customer's premises for necessary purposes in connection with rendering of service, including meter installation, reading or testing, or the maintenance or removal of the property of Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 27**

STANDARD TERMS AND CONDITIONS
(Continued)

Public Service ~~The Company~~ shall apply the regulations set forth in N.J.A.C. 14:3.3A.2(a), and only discontinue service for non-payment of bills if one or both of the following criteria are met: 1) the customer's arrearage is more than $~~100~~200.00; and/or 2) the customer's account is more than 3 months in arrears.

Public Service may not discontinue service for non-payment of bills unless it gives the customer at least 10 days written notice of its intentions to discontinue service, 15 days if a landlord-tenant relationship is known to exist. The notice of discontinuance shall not be served until the expiration of the 15-day period indicated in Section 8.12 Payment of Bills of these Standard Terms and Conditions. No additional notice will be required when, in a response to a notice of discontinuance, payment by check is subsequently dishonored. However, in case of fraud, illegal use, or when it is clearly indicated that the customer is preparing to leave, immediate payment of accounts may be required.

Public Service may not discontinue service because of non-payment of bills in cases where a charge is in dispute, provided that the undisputed charges are paid and a request is made to the Board for investigation of the disputed charge. In such cases, Public Service shall notify the customer that unless steps are taken to invoke formal or informal Board action within 5 days, service will be discontinued for non-payment.

Public Service may not discontinue residential service involuntarily except between the hours of 8:00 A.M. ~~to~~ and 4:00 P.M. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Friday, Saturday, and Sunday or on the day before a holiday or on a holiday, absent such emergency.

Subject to the conditions set forth below, d~~D~~iscontinuance of residential service for non-payment is prohibited if a medical emergency exists within the premises which would be aggravated by discontinuance of service. ~~and the customer gives reasonable proof of inability to pay.~~ Discontinuance shall be prohibited for a period of ~~up to 2 months~~90 days initially when a customer submits a ~~physician's statement~~licensed medical professional's statement in writing to Public Service as to the existence of the emergency, its nature and probable duration, and that termination of service will aggravate the medical emergency. Public Service may also require the customer to give reasonable proof of inability to pay. ~~Recertification by the physician as to continuance of the medical emergency shall be submitted to Public Service after 30 days.~~ However, at the end of such period of emergency, the customer shall still remain liable for payment of service(s) rendered, subject to the provision of N.J.A.C. 14:3-7.7.

1. The Board may extend the ~~6~~90-day period for good cause upon the receipt of a written request from the customer. ~~That~~The written request shall be in accordance with the preceding terms. Pending the Board's consideration and decision regarding the request for extension, service shall not be discontinued.

2. Public Service may in its discretion, delay discontinuance of residential service for nonpayment prior to submission of the licensed medical professional's~~physician's~~ statement required by this subsection when a medical emergency is known to exist.

If Public Service disconnects service to an unknown account and is notified that a medical emergency exists in the residential premises, Public Service shall: (1) restore service immediately; (2) allow 14 days to apply for service; and (3) allow 7 additional days following the service activation date or 21 days following the date it is notified of a medical emergency, whichever date is later, to submit a medical certification to Public Service written by a licensed medical professional in accordance with the preceding terms.

If a residential customer offers payment of the full amount or a reasonable portion of the amount due at the time of discontinuance, a Public Service representative shall accept payment without discontinuance of service. Whenever such payment is made, the representative shall provide the customer with a receipt showing the date, account number, customer's name and address and amount received.

in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 28**

STANDARD TERMS AND CONDITIONS
(Continued)

Public Service shall make every reasonable effort to determine when a landlord-tenant relationship exists at residential premises being served. If such a relationship is known to exist, and if the tenants are not the customers of record but are ~~end~~ end-users, service will not be ~~shut off~~discontinued unless Public Service has given a 15-day written notice to the owner of the premises or to the customer of record to whom the last preceding bill was rendered. Public Service will use its best efforts to provide discontinuance notices to all tenants, including providing tenants with a 15-day written notice, which will be ~~hand~~ hand-delivered, mailed or posted in a conspicuous area of the premises and in the common areas of multiple family premises.

In addition, if posting is the method of notification used, Public Service will use its best efforts to place a copy of the notice on each tenant's car windshield or under the door of each tenant's dwelling. In the case of tenants of single and two-family dwellings, each tenant will be provided with a 15-day individual notice.

When a landlord-tenant relationship is known to exist, at the landlord's request, Public Service will provide the landlord with notice and/or have the service placed in the landlord's name if the tenant's service is being discontinued.

If Public Service disconnects service to a master metered premises in which the landlord is the actual customer of record and Public Service has been notified that a medical emergency exists by a tenant, Public Service shall restore service for a period of 7 days to allow the customer of record to resolve the nonpayment issue and to provide the tenant with time to make alternative arrangements.

Public Service shall not discontinue service during the period from November 15 through March 15, in accordance with N.J.A.C. 14:3-3A.5(a), unless otherwise ordered by the Board of Public Utilities, to those residential customers who demonstrate at the time of the intended termination that they are: (1) recipients of benefits ~~of: (1)~~under the Lifeline Credit Program; (2) recipients of benefits under the Federal Home Energy Assistance Program (HEAP)~~; (3)~~, or certified as eligible therefor under standards set by the New Jersey Department of Human Services; (3) recipients of Temporary Assistance to Needy Families (TANF); (4) recipients of Federal Supplemental Security Income (SSI); (5) recipients of Pharmaceutical Assistance to the Aged and Disabled (PAAD); (6) recipients of General Assistance (GA) benefits; (7) recipients of the Universal Service Fund (USF); or (8) ~~Persons~~ persons unable to pay their utility bills because of circumstances beyond their control.

Public Service shall not discontinue service to any residential customer, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with the terms of a deferred payment plan, whenever the high temperature is forecast to be 32 degrees Fahrenheit or below during the next 24 hours, in accordance with N.J.A.C. 14:3-3A.2(e)1.

Public Service shall not discontinue service to any residential customer eligible for the Winter Termination Program, for reasons of nonpayment, failure to pay a cash security deposit or guarantee, or failure to comply with a deferred payment agreement, whenever the high temperature is forecast to be ~~95~~ 90 degrees Fahrenheit or more at any time during the following 48 hours, in accordance with N.J.A.C. 14:3-3A.2(e)3.

11.2. At Customer's Request: A customer wishing to discontinue service must give notice as provided in the applicable rate schedule. Within 48 hours of said notice, Public Service will discontinue service or obtain a meter reading for the purpose of calculating a final bill. Where such notice is not received by Public Service, customer shall be liable for service until final reading of the meter is taken. Notice to discontinue service will not relieve a customer from any minimum or guaranteed payment under any contract or rate schedule.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 29**

STANDARD TERMS AND CONDITIONS
(Continued)

12. RECONNECTION CHARGE

A reconnection charge of $45.00 will be made for restoration of service when service has been suspended or discontinued for non-payment of any bill due.

13. SERVICE LIMITATIONS

13.1. Continuity of Service: Public Service will use reasonable diligence to provide a regular and uninterrupted supply of service; but, should the supply be suspended, curtailed, or discontinued by Public Service for any of the reasons set forth in Section 11 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective, or fail, by reason of any act of God, accident, strike, legal process, governmental interference, or by reason of compliance in good faith with any governmental order or directive, notwithstanding such order or directive subsequently may be held to be invalid, Public Service shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure.

13.2. Emergencies: Public Service may curtail or interrupt service to any customer or customers in the event of an emergency threatening the integrity of its system or the systems to which it is directly or indirectly connected if, in its sole judgment, such action will prevent or alleviate the emergency condition.

13.3. Unusual Conditions: Public Service may place limitations on the amount and character of gas service it will supply or transport and may refuse such service to new customers, to existing customers for additional load, or to customers whose service agreements have expired if Public Service is or will be unable to obtain or does not have assured the necessary production raw materials, equipment and facilities to supply such gas or transportation service. In the case of transportation service, if Public Service, at its sole discretion, determines that such service would not be consistent with the best interest of its customers served under all rate schedules contained herein such service may be denied to applicants for such service.

14. THIRD PARTY SUPPLIER SERVICE PROVISIONS

14.1. Third Party Supplier Gas Supply: Customers served on Rate Schedules RSG, GSG, LVG, SLG, TSG-NF, and CSG may choose to receive gas supply from either a Third Party Supplier (TPS) or from Public Service through its Basic Gas Supply Service. Customers on these rate schedules who are not enrolled with a TPS will receive their gas supply from Public Service. Customers served on Rate Schedule TSG-F may only receive gas supply from a TPS. The customer's supply of gas is limited to one TPS for the account(s) at a particular customer facility or complex.

A TPS is either a retail energy provider that has been licensed by the Board or is a customer served under Rate Schedules TSG-NF and CSG that has elected to self supply and act as a TPS on their own behalf. All TPSs must execute an Application for Service, be accepted by Public Service, and conform with the Third Party Supplier Requirements section of this Tariff.

14.2. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding gas supply describes the process necessary for a customer to obtain a TPS for gas supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center. Once the customer has chosen a TPS, the customer must provide appropriate authorization as required by their designated supplier.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 30**

STANDARD TERMS AND CONDITIONS
(Continued)

14.3. Selection or Change of Third Party Supplier: In order to be eligible to receive gas supply from a TPS, the customer must contract with a TPS to obtain gas supply for delivery to the customer by Public Service. The customer's designated TPS is required to notify Public Service of its selection as the customer's provider of gas supply on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month for Rate Schedules RSG, GSG, LVG, and SLG. Notification for customers on Rate Schedules TSG-F, TSG-NF, and CSG is required prior to the last business day of the month. Such selection shall remain in effect for the entire billing period.

For customers on Rate Schedule RSG, GSG, LVG, SLG, TSG-F, TSG-NF and CSG, once Public Service has received the TPS notification for the initial, or subsequent, enrollment with a TPS, Public Service will confirm the customer's selection of its designated TPS by sending a letter of confirmation to the customer, which will be sent within one business day. In the event of a dispute, assignment of a customer will not occur unless and until the dispute is resolved. This confirmation letter will include notification of the RSG customer's right to rescind their contract with their designated TPS which must be exercised within seven (7) days of mailing of the letter of confirmation. Once assignment has occurred, the TPS will be required to supply all of the gas supply on the Public Service customer's account.

14.4. Return to Public Service Basic Gas Supply Service Default Service: Customers may return to Public Service Basic Gas Supply Service default service for commodity supply under the conditions and procedures as outlined below.

14.4.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: Customers that subsequently choose to return to Basic Gas Supply Service default service must notify Public Service on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day. This confirmation letter will include notification of the customer's right to rescind their selection which must be exercised within seven (7) days of mailing of the letter of confirmation. GSG, LVG, and SLG customers not exercising their right of rescission within the seven (7) day period may be subject to renewable one-year terms on Basic Gas Supply Service default service.

If a customer's TPS notifies Public Service on or before the 10th calendar day of the month that it has terminated its supply relationship with the customer, such termination will become effective on the first scheduled meter reading date beginning with the first calendar day of the following month. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 31**

STANDARD TERMS AND CONDITIONS
(Continued)

14.4.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): For customers that subsequently choose to return to Basic Gas Supply Service default service, the return will become effective on the first of the month following the customer's written notification to Public Service, provided that such notice was given prior to the last business day of the preceding month. Public Service will confirm the customer's selection of Basic Gas Supply Service default service gas supply by sending a letter of confirmation to the customer, which will be sent within one business day.

If a customer's TPS notifies Public Service that it has terminated its supply relationship with the customer, such termination will become effective on the first of the month after such notification, provided such notification was received no later than the next to last business day of the month. In the event that notification is received after the next to last business day of the month, such termination shall become effective the first of the second month following such notification. The customer will be advised by Public Service in writing of this change in supplier. The customer will be placed on the applicable Public Service Basic Gas Supply Service default service unless the customer has selected another TPS in accordance with Section 14.3.

14.4.3. Customers on Rate Schedule TSG-F: Basic Gas Supply Service default service is not available for customers on Rate Schedule TSG-F.

14.5. Emergency Sales Service: Under certain conditions as specified below, Public Service may supply gas commodity on the Emergency Sales Service provision. Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

14.5.1. Customers on Rate Schedules RSG, GSG, LVG and SLG: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, until the customer's next meter reading date the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its applicable Daily Contract Quantity (DCQ) therms. Thereafter, the customer will be placed on the applicable Public Service Basic Gas Supply Service default service. GSG, LVG, and SLG customers provided Basic Gas Supply Service default service for two or more consecutive months may be subject to renewable one-year terms on Basic Gas Supply Service default service.

14.5.2. Customers on Rate Schedules TSG-NF and CSG (with maximum requirement of less than 2,000 therms per hour): During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that, for the balance of the current month the customer will be billed, in addition to all applicable delivery charges, the Emergency Sales Service Charge for all of its therm usage. Commencing on the first of the following month the customer will be placed on the applicable Public Service Basic Gas Supply Service default service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 32**

STANDARD TERMS AND CONDITIONS
(Continued)

14.5.3. Customers on Rate Schedule TSG-F: During any month where Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supply Requirements section of this tariff, Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS in accordance with Section 14.3. The customer will be advised by Public Service in writing that the customer will be billed, in addition to all applicable delivery charges the Emergency Sales Service Charge for all of its therm usage.

14.6. Customer Billing Process: For TPS retail customers served under Rate Schedule RSG, GSG, LVG and SLG, Public Service will provide one combined bill containing both Public Service charges and TPS gas supply charges, providing the TPS executes and satisfies the terms of the Third Party Supplier Customer Account Services Master Service Agreement, and the retail customer(s) maintain a satisfactory bill payment history. Customer(s) may elect to receive a separate bill directly from its TPS for third party supplied services. If a customer requests and is permitted to receive a combined bill, but the customer's account subsequently becomes 120 days in arrears at any point in the future, such customer will thereafter be required to receive a separate bill directly from its TPS (including any subsequent TPS) for third party supplied services and will not be permitted to receive a combined bill from Public Service until such time the customer's arrearage is reduced to 60 days or less. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

14.6.1. Payment of Bills: Where Public Service provides billing service, the payment of bills, including TPS's charges for gas supply if billed by Public Service, will be made to Public Service and will be in accordance with Section 8, Meter Reading and Billing, of these Standard Terms and Conditions. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request.

14.6.2. Late Payment Charges: A late payment charge in accordance with Section 8.13, Late Payment Charge, of these Standard Terms and Conditions is to be applicable to Public Service customer charges and TPS's charges for gas supply if billed by Public Service. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges and TPS's charges for gas supply if billed by Public Service, are only performed in accordance with Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

14.6.3. Billing Disputes: In the event of a billing dispute between the customer and the TPS, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges and all undisputed TPS charges for gas supply if such charges are billed by Public Service in accordance with Section 8, Meter Reading and Billing, and Section 14.6.1, Payment of Bills, of these Standard Terms and Conditions. All questions regarding TPS's charges or other terms of the customer's agreement with a TPS are to be resolved between the customer and its TPS. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between TPS customer and TPS. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 11, Discontinuance of Service, of these Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 33**

STANDARD TERMS AND CONDITIONS
(Continued)

14.7. Third Party Supplier's Termination of Customer's Gas Supply: A TPS will not be permitted to physically connect or disconnect gas supply service to a customer.

14.8. Continuity of Service: Public Service shall have the right: (i) to require a TPS's gas supply sources to be disconnected from Public Service's gas system; (ii) to otherwise curtail, interrupt, or reduce a TPS's gas supply; or (iii) to disconnect a TPS's customer(s) in accordance with Section 11, Discontinuance of Service, and Section 13, Service Limitations, of these Standard Terms and Conditions.

14.9. Regulatory Requirements: Public Service will not be responsible for: making any arrangements necessary; obtaining from appropriate regulatory bodies any approvals necessary; any costs, charges and expenses including but not limited to the payment to appropriate governmental entities for any tax or assessment relative to the acquisition, transportation or use of customer's gas supply.

14.10. Delivery Liability: Public Service will not be liable in any way for any failure in whole or in part, temporary or permanent, to deliver gas under this Tariff for Gas Service to the extent such failure is due to customer's TPS's failure to deliver gas supplies to Public Service in accordance with the TPS Requirements. Public Service will not be liable in any way for errors in the calculation of the customer's DCQ and/or delivery requirement.

14.11. Delivery Control and Possession: After customer delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

15. NEW JERSEY AUTHORIZED TAXES

The following taxes are authorized by the State of New Jersey and are applied in accordance with P.L. 1997, c. 162 (the "Energy Tax Reform Statute"), as amended by P.L. 2006, c. 44, as amended by P.L. 2009, c. 240 and P.L. 2016, c. 57, and are included in the appropriate charges contained within this Tariff for Gas Service.

15.1. New Jersey Sales and Use Tax: In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax (SUT) has been included in all applicable charges by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

15.1.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b-1) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 34**

STANDARD TERMS AND CONDITIONS
(Continued)

b-2) Cogeneration facilities that are constructed after January 1, 2010.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Agencies or instrumentalities of the federal government.

e) International organizations of which the United States of America is a member.

f) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57.

15.1.2. Exemptions due to the Business Retention and Relocation Assistance Act: The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

a) A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

b) A group of two or more persons:

(b-1) Each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 *et seq.*);
(b-2) That collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;
(b-3) Are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and
(b-4) Collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.

c) A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (a), (b) or (c) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c. 303 (C.52:27H-60 *et seq.*) and P.L.1966, c. 30 (C.54:32B-1 *et seq.*) and Public Service has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

15.2. New Jersey Corporation Business Tax: In accordance with P.L. 1997, c. 162, provision for the New Jersey Corporation Business Tax (CBT) has been included in the Service Charge, Distribution Charge, and the Demand Charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 35**

STANDARD TERMS AND CONDITIONS

(Continued)

15.2.1. Exemptions due to the Energy Tax Reform Statute: The Energy Tax Reform Statute exempts the following customers from the CBT provision, and when billed to such customers, the above tariff charges otherwise applicable shall be reduced by the provision for the CBT (and related SUT) included therein.

a) Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.

b) Cogenerators in operation, or which had filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 *et seq.*) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

c) Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

d) Additional customers as authorized by the State of New Jersey Department of Treasury in accordance with the provisions of P.L. 1997, c. 162.

16. NEW JERSEY AUTHORIZED EXEMPTIONS

The following exemptions are authorized by the State of New Jersey and are applied in accordance with P.L. 2011, c.9 (the "Long Term Capacity Agreement Pilot Program", "LCAPP Legislation"). The exemptions take effect January 28, 2011.

16.1. Exemptions due to LCAPP Legislation: Electric generators who use natural gas to generate electricity that is sold for resale will be exempt from a societal benefits charge pursuant to N.J.S.A. 48:3-60.1 or any other charge designed to recover the costs for social, energy efficiency, conservation, environmental or renewable energy on natural gas delivery service or commodity that is used to generate electricity that is sold for resale. This exemption includes the Societal Benefits Charge (SBC) and the Green Programs Recovery Charge (GPRC). Each customer's exemption will be effective upon completion of an Annual Certification form.

a) The Annual Certification form shall be a prerequisite for the exemption and shall be furnished to customers of record in December and returned to Public Service by the customer no later than January 15th of each year. The Annual Certification form shall certify the percentage of gas used at their New Jersey generation facilities during the immediately preceding calendar year to generate electricity that was sold for resale. This Certification will serve as the percentage of the customers' throughput that will be exempt from the SBC and the GPRC. This Certification will then be used for the succeeding annual period commencing in February. If the customer fails to return the form, then the SBC and the GPRC will be assessed on all of the customer's usage until a completed Annual Certification form is received to be effective after the next subsequent meter reading. If the customer returns a completed Annual Certification Form on or before January 15, then adjustments to customer's bills to reflect changes in the percentage of gas used to generate electricity for resale will be made on a prospective basis beginning in February.

b) In those cases where prior calendar year usage is not available, the customer will submit an Annual Certification form with an estimated percentage of gas that will be used at their New Jersey generation facilities for the current calendar year to generate electricity to be sold for resale. Once agreement has been reached with PSE&G regarding the estimated percentage, the completed Certification will serve as the percentage of the customers' throughput that will be exempt from the SBC and the GPRC effective after the next subsequent meter reading on a prospective basis for the remainder of the current calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 36**

STANDARD TERMS AND CONDITIONS
(Continued)

17. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 37
Original Sheet No. 38
Original Sheet No. 39
Original Sheet No. 40

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 41**

SOCIETAL BENEFITS CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Social Programs	$ 0.000000
Energy Efficiency and Renewables Programs	0.019520
Manufactured Gas Plant Remediation	0.008753
Universal Service Fund - Permanent	0.010800
Universal Service Fund - Lifeline	0.005800
Societal Benefits Charge	$ 0.044873
Societal Benefits Charge including New Jersey Sales and Use Tax (SUT)	$ 0.047846

Societal Benefits Charge

This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under-over recovered balances for all components other than Manufactured Gas Plant Remediation. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances for the Manufactured Gas Plant Remediation. The interest rates for all components other than USF and Lifeline shall change each August 1. The interest rates for the USF and Lifeline components shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Ninth Revised Sheet No. 41 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 42**

SOCIETAL BENEFITS CHARGE
(Continued)

SOCIAL PROGRAMS

This factor shall recover costs associated with existing social programs.

ENERGY EFFICIENCY AND RENEWABLES (EE&R) PROGRAMS

This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations and successor regulations. The factor has been used to recover past Core and Performance Program Costs and Performance Program Payments, payments for Large-Scale Conservation Investments, and all recoverable costs associated with the Board's Comprehensive Resource Analysis Orders, including but not limited to the low income Comfort Partners Program.

MANUFACTURED GAS PLANT REMEDIATION

This factor shall recovery costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

UNIVERSAL SERVICE FUND

These factors shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 43**

MARGIN ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG, TSG-F
(Per Therm)

Margin Adjustment Charge ..... ($0.005821)

Margin Adjustment Charge including New Jersey Sales and Use Tax (SUT)..... ($0.006207)

Margin Adjustment Charge

This mechanism is designed to insure return of certain net revenues to the customer classes denoted above. Actual net revenues will be subject to deferred accounting. Interest at the seven-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 43 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 44**

GREEN PROGRAMS RECOVERY CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Carbon Abatement Program	($0.000470)
Energy Efficiency Economic Stimulus Program	0.000167
Energy Efficiency Economic Extension Program	0.000329
Energy Efficiency Economic Extension Program II	0.000472
Energy Efficiency 2017 Program	0.003000
Clean Energy Future – Energy Efficiency Program	0.005528
Green Programs Recovery Charge	$0.009026

Green Programs Recovery Charge including New Jersey Sales and Use Tax SUT $0.009624

Green Programs Recovery Charge

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rate shall be reset each month.

See Section 16 of the Standard Terms and Conditions for exemptions from this charge.

(Charges are for illustrative purposes only and are based on the Eighth Revised Sheet No. 44 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48**

CONSERVATION INCENTIVE PROGRAM

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG
(Per Therm)

	Conservation Incentive Program	Conservation Incentive Program including SUT
RSG	$0.060736	$0.064760
GSG	$0.044451	$0.047396
LVG	$0.004748	$0.005063

Conservation Incentive Program

This charge shall be applicable to the rate schedules listed above. The Conservation Incentive Program shall be based on the differences between actual and allowed usage per customer during the preceding annual period. The Conservation Incentive Mechanism shall be determined as follows:

I. DEFINITION OF TERMS AS USED HEREIN

1. Actual Number of Customers
– the Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") Clause applies. The ANC shall equal the aggregate actual monthly Service Charge revenue for each class of customers subject to the CIP as recorded on the Company's books, divided by the service charge rate applicable to such class of customers in each Customer Class Group.

2. Actual Usage Per Customer
– the Actual Usage per Customer ("AUC") shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the ANC for the corresponding month.

3. Adjustment Period
– shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period
– shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

5. Average 13 Month Common Equity Balance
– shall be the average of the beginning and ending common equity balances based on the latest publically available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

6. Baseline Usage per Customer
– the Baseline Usage per Customer ("BUC") shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

The BUC shall be reset each time new base rates are placed into effect through a base rate case.

(Charges are for illustrative purposes only and are based on the Third Revised Sheet No. 48 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48A**

CONSERVATION INCENTIVE PROGRAM
(Continued)

7. Customer Class Group
– for purposes of determining and applying the CIP, customers shall be aggregated into three separate recovery class groups. The Customer Class Groups shall be as follows:

Group I: RSG
Group II: GSG
Group III: LVG

8. Forecast Annual Usage
– the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

9. Margin Revenue Factor
– the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I (RSG): $0.437483
Group II (GSG): $0.328242
Group III (LVG): $0.046383

The MRF shall be reset each time new base rates are placed into effect, including Infrastructure Investment Program ("IIP") or all other future base rate changes.

10. Degree Days (DD)
– the difference between 65^{o}F and the mean daily temperature for the day. The mean daily temperature is the simple average of the 24 hourly temperature observations for a day.

11. Actual Calendar Month Degree Days
– the accumulation of the actual Degree Days for each day of a calendar month.

12. Normal Calendar Month Degree Days
– the level of calendar month degree days to which the weather portion of the CIP applies.

The normal calendar month Degree Days will be the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station at the Newark airport and will be updated annually. The base level of normal HDD for the defined winter period months for the 2023-2024 Winter Period are set forth in the table below:

Month	Normal Heating Degree Days
October 2023	225.14
November 2023	515.50
December 2023	810.29
January 2024	1,005.68
February 2024	868.22
March 2024	682.63
April 2024	355.17
May 2024	123.16

13. Winter Period
– shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48B**

CONSERVATION INCENTIVE PROGRAM
(Continued)

14. Degree Day Consumption Factors
– the use per degree day component of the gas sales equations by month used in forecasting firm gas sales for the applicable rate schedules. Degree day Consumption Factors for the 2023-2024 Winter Period are set forth below and presented as therms per degree day:

	RSG-Residential		Commercial			Industrial		
Month			GSG		LVG	GSG		LVG
	Heating	Non- Heating	Heating	Non- Heating		Heating	Non- Heating	
Oct.-23	183,348	-	-	-	88,624	633	-	7,326
Nov.-23	269,657	2,352	34,861	2,625	88,624	1,220	139	7,321
Dec.-23	269,443	3,088	51,188	3,709	88,624	2,154	259	7,315
Jan.-24	303,067	3,111	52,644	3,907	90,462	2,463	234	7,452
Feb.-24	291,037	2,723	54,216	4,014	90,462	1,934	138	7,445
Mar.-24	293,337	3,012	55,149	4,047	90,462	2,215	243	7,437
Apr.-24	285,355	3,138	57,596	4,118	90,462	1,748	229	7,428
May-24	209,054	3,458	29,705	3,863	90,462	1,160	163	7,418

II. BASELINE USE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	RSG	GSG	LVG
Oct.	38.7	110.8	2,350.0
Nov.	87.6	172.0	3,486.2
Dec.	144.9	320.4	5,220.9
Jan.	180.6	421.1	6,506.4
Feb.	153.5	351.6	5,940.9
Mar.	124.5	275.8	5,478.7
Apr.	70.4	170.7	3,703.5
May	37.0	80.1	2,037.8
Jun.	21.0	49.2	1,477.0
Jul.	18.0	58.5	1,374.6
Aug.	18.0	50.5	1,379.9
Sep.	19.5	52.6	1,322.8
Total Annual	**913.7**	**2,113.3**	**40,278.7**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 48C**

CONSERVATION INCENTIVE PROGRAM
(Continued)

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

2. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.9. of this rate schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather related deficiency or excess.

3. Recovery of margin deficiency associated with non-weather related deficiency in customer usage will be subject to a BGSS savings test and a Variable Margin Revenue recovery limitation (“recovery tests”). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 4.0 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this rate schedule.

4. In addition, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13 Month Common Equity Balance by the Company's average common equity balance for the same period, all as reflected in the Company's monthly reports to the Board of Public Utilities. The Company's net income shall be calculated by subtracting from total operating income, any clause related Net Income, such as the Green Program’s Recovery Charge and interest expenses. The Company's Average 13 Month Common Equity Balance shall be the ratio of Gas Net Plant (including the Gas allocation of Common Plant) to total PSE&G Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV**. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM**

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 49
Original Sheet No. 50

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 51**

TAX ADJUSTMENT CREDIT

Rate Schedule	Charge per Therm	Charge per Therm Including SUT
RSG	($0.064753)	($0.069043)
GSG	($0.054983)	($0.058626)
LVG	($0.025916)	($0.027633)
SLG	($0.094749)	($0.101026)
TSG-F	($0.022261)	($0.023736)
TSG-NF	($0.011569)	($0.012335)
CIG	($0.017044)	($0.018173)
CSG	($0.001181)	($0.001259)

Tax Adjustment Credit

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 51 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 52**

DISTRIBUTION ADJUSTMENT CHARGE

CHARGE APPLICABLE TO
RATE SCHEDULES RSG, GSG, LVG, SLG,
TSG-F, TSG-NF, CIG, CSG
(Per Therm)

Component:

Storm Recovery Charge	$0.XXXXXX
COVID-19 Cost Recovery	0.XXXXXX
Distribution Adjustment Charge	$0.XXXXXX
Distribution Adjustment Charge including New Jersey Sales and Use Tax SUT	$0.XXXXXX

Distribution Adjustment Charge

This charge is designed to recover Board-approved costs. The charge will be reset nominally on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under- or over- recovered balances. The interest rates shall be reset each month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

~~**Original Sheet No. 52**~~
Original Sheet No. 53

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 54**

BGSS-RSG
BASIC GAS SUPPLY SERVICE-RSG
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE RSG
(Per Therm)

Estimated Non-Gulf Coast Cost of Gas	$0.074813
Estimated Gulf Coast Cost of Gas	0.339920
Adjustment to Gulf Coast Cost of Gas	0.000000
Prior period (over) or under recovery	(0.049390)
Adjusted Cost of Gas	0.365343
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$0.372799
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$0.397497

The above Commodity Charge will be established on a level annualized basis immediately prior to the winter season of each year for the succeeding twelve-month period. The estimated average Non-Gulf and Gulf Coast Cost of Gas will be adjusted for any under- or over-recovery together with applicable interest thereon which may have occurred during the operation of the Company's previously approved Commodity Charge filing. Further, the Company will be permitted a limited self-implementing increase to the Commodity Charge on December 1 and February 1 of each year. These limited self-implementing increases, if applied, are to be in accordance with a Board of Public Utilities approved methodology. Commodity Charge decreases would be permitted at any time if applicable.

The difference between actual costs and Public Service's recovery of these costs shall be determined monthly. If actual costs exceed the recovery of these costs, an underrecovery or a negative balance will result. If the recovery of these costs exceeds actual costs, an overrecovery or a positive balance will result. Interest shall be applied monthly to the average monthly cumulative deferred balance, positive or negative, from the beginning to the end of the annual period. Monthly interest on negative deferred balances (underrecoveries) shall be netted against monthly interest on positive deferred balances (overrecoveries) for the annual period. A cumulative net positive interest balance at the end of the annual period is owed to customers and shall be returned to customers in the next annual period. A cumulative net negative interest balance shall be zeroed out at the end of the annual period. The sum of the calculated monthly interests shall be added to the overrecovery balance or subtracted from the underrecovery balance at the end of the annual period. The positive interest balance shall be rolled into the beginning under- or over-recovery balance of the subsequent annual period.

Pursuant to the Board's January 6, 2003 Order approving the BGSS price structure under Docket No. GX01050304 and the BGSS Pricing Proposal appended as Attachment A to and approved in that Order, Public Service Electric and Gas Company may issue a bill credit for its BGSS-RSG customers as detailed below.

Effective	BGSS-RSG Credit (per therm)	BGSS-RSG Credit including SUT (per therm)
February 1, 2020 through March 31, 2020	($0.070340)	($0.075000)
April 1, 2020	$0.000000	$0.000000

(Charges are for illustrative purposes only and are based on the Twenty-Third Revised Sheet No. 54 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 55**

BGSS-F
BASIC GAS SUPPLY SERVICE-FIRM
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULES GSG, LVG, SLG, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.499741
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.532849
FLOOR PRICE:	Non-Gulf Coast Cost of Gas component	$ 0.173461
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-F for the month	0.198685
	Total Cost of Gas	$ 0.372146
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.379741
CEILING PRICE:	Commodity Charge	$ 0.505582

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the applicable charge for Emergency Sales Service.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month plus other fixed adjustments of a negative $0.050515 per therm.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 55 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 56**

BGSS-I
BASIC GAS SUPPLY SERVICE-INTERRUPTIBLE
COMMODITY CHARGE APPLICABLE TO RATE SCHEDULES TSG-NF, CSG
(Per Therm)

COMMODITY CHARGE:	Commodity Charge	$ 0.462786
	Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.493446
FLOOR PRICE:	50% of the Non-Gulf Coast Cost of Gas component	$ 0.086730
	Variable Cost of Commodity and Fuel	0.000000
	Cost of Gas Acquired to serve BGSS-I for the month	0.249200
	Total Cost of Gas	$ 0.335930
	Floor Price after application of losses (Loss Factor = 2.0%)	$ 0.342786
CEILING PRICE:	Floor Price plus $0.18	$ 0.522786

A market based charge including all applicable taxes to be posted by Public Service on a monthly basis. The foregoing Commodity Charge will be subject to a floor price equal to the sum of 50% of the Non-Gulf Coast Cost of Gas component and the Cost of Gas Acquired for these customers. Additionally, this Commodity Charge will not exceed a Ceiling Price equal to the Floor Price plus 18 cents per therm.

The Cost of Gas Acquired will be established prior to the beginning of each month based on the NYMEX closing price for the following month.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 56 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 57**

BGSS-CIG
BASIC GAS SUPPLY SERVICE – COGENERATION INTERRUPTIBLE
COMMODITY CHARGES APPLICABLE TO RATE SCHEDULE CIG
(Per Therm)

COMMODITY CHARGE:

Estimated Average Commodity Cost for the month	$ 0.249200
Variable Cost of Commodity and Fuel	0.000000
50% Weighted Average Pipeline Demand Costs	0.022352
Total Commodity Cost of Gas for the month	$ 0.271552
Total Commodity Cost of Gas after application of losses (Loss Factor = 2.0%)	$ 0.277094
Cogeneration Facilities in Service on or before March 10, 1997.	$ 0.277094
Cogeneration Facilities in Service after March 10, 1997 (Charges include New Jersey Sales and Use Tax)	$ 0.295451

Combined Commodity and Distribution Charge – Information Only:

Cogeneration Facilities in Service on or before March 10, 1997

Sum of a Distribution Charge of $0.088960 per therm for the first 600,000 therms used in each month plus the above Commodity Charge	$ 0.366054
Sum of a Distribution Charge of $0.078960 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge	$ 0.356054

Cogeneration Facilities in Service after March 10, 1997
(Charges include New Jersey Sales and Use Tax)

Sum of a Distribution Charge of $0.094854 per therm for the first 600,000 therms used in each month plus the above Commodity Charge	$ 0.390305
Sum of a Distribution Charge of $0.084191 per therm in excess of 600,000 therms used in each month plus the above Commodity Charge	$ 0.379642

The monthly Distribution Charges for Rate Schedule CIG are shown on Sheet No. 107.

(Charges are for illustrative purposes only and are based on the Fifty-Eighth Revised Sheet No. 57 filed with the BPU on July 28, 2023)

Date of Issue: Effective:
Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 58**

EMERGENCY SALES SERVICE
CHARGE APPLICABLE TO RATE SCHEDULES RSG, GSG, LVG,
SLG, TSG-F, TSG-NF, CSG
(Per Therm)

Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC)	$ 0.044850
Public Service's BGSS supplier(s)'s highest cost of gas purchased or used by Public Service during the month	0.269620
A charge of $0.181	0.181000
Total	$ 0.495470
Emergency Sales Service Charge after application of losses (Loss Factor = 2.0%)	$ 0.505582
Emergency Sales Service Charge including New Jersey Sales and Use Tax (SUT)	$ 0.539077

The charge for Emergency Sales Service will equal the sum of: (1) Public Service's BGSS supplier(s)'s weighted average pipeline transportation cost including fuel, calculated at 100% load factor (WATC); (2) Public Service's BGSS supplier(s)'s highest cost of gas purchased or used during that month, (including associated storage costs, if any); (3) a charge of 18.1 cents per therm; (4) application of losses; and (5) all other applicable taxes and surcharges.

~~For Rate Schedule CSG, t~~This service is only available for customers with a maximum requirement of 2,000 therms per hour.

(Charges are for illustrative purposes only and are based on the Fifty-Seventh Revised Sheet No. 58 filed with the BPU on July 28, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 59**

BGSS-RSGOP
BASIC GAS SUPPLY SERVICE-RSG OFF-PEAK

COMMODITY CHARGE APPLICABLE TO
RATE SCHEDULE RSG OFF-PEAK USE
(Per Therm)

Cost of Off-Peak RSG Gas Acquired	$ 0.263220
20% of the Non-Gulf Coast Cost of Gas seasonal component	0.010280
Total Cost of Gas	$ 0.273500
Commodity Charge after application of losses: (Loss Factor = 2.0%)	$ 0.279082
Commodity Charge including New Jersey Sales and Use Tax (SUT)	$ 0.297571

The Commodity Charge will be established on a level basis for the billing months of May to October immediately prior to the Off-Peak season of each year. The Commodity Charge will equal the Cost of Off-Peak RSG Gas Acquired (plus the variable pipeline transportation cost including fuel) and 20% of the Non-Gulf Coast Cost of Gas seasonal component. The Commodity Charge will be adjusted for losses.

The Cost of Off-Peak RSG Gas Acquired will be established prior to the beginning of the Off-Peak period based on the average NYMEX closing price for the first 15 days of April for natural gas to be supplied in the months of May through October.

(Charges are for illustrative purposes only and are based on the Fifth Revised Sheet No. 59 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 60**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
RSG					
Service Charge	per Month	$8.62	$0.00	$0.00	$8.62
Distribution Charges	per therm	0.046399	0.002603	0.002775	0.466475
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use	per therm	0.231851	0.001301	0.001388	0.233238
GSG					
Service Charge	per Month	20.09	0.13	0.14	20.23
Distribution Charge - Pre July 14, 1997	per therm	0.348581	0.001341	0.001430	0.350010
Distribution Charge - All Others	per therm	0.348581	0.001341	0.001430	0.350010
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
Off-Peak Use Dist Charge - Pre July 14, 1997	per therm	0.174290	0.000670	0.000715	0.175005
Off-Peak Use Dist Charge - All Others	per therm	0.174290	0.000670	0.000715	0.175005
LVG					
Service Charge	per Month	178.38	1.20	1.28	179.66
Demand Charge	per Demand therm	4.6464	0.0177	0.0188	4.6653
Distribution Charge 0-1,000 pre July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 pre July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Distribution Charge 0-1,000 post July 14, 1997	per therm	0.035914	(0.000629)	(0.000671)	0.035244
Distribution Charge over 1,000 post July 14, 1997	per therm	0.052989	0.000404	0.000431	0.053420
Balancing Charge	per Balancing therm	0.097914	0.000000	0.000000	0.097914
SLG					
Single-Mantle Lamp	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double-Mantle Lamp, inverted	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Double Mantle Lamp, upright	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, prior to January 1, 1993	per Unit per Month	14.1119	0.0000	0.0000	14.1119
Triple-Mantle Lamp, on and after January 1, 1993	per Unit per Month	71.9465	0.0000	0.0000	71.9465
Distribution Therm Charge	per therm	0.056854	0.000210	0.000224	0.057077

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

(Charges are for illustrative purposes only and are based on the Sixth Revised Sheet No. 60 filed with the BPU on October 1, 2023)

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 61**

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGES (Continued)

Rate Schedule		Base Distribution Charges Including SUT*	Energy Strong II Charges	Energy Strong II Charges Including SUT	Total Charges Including SUT
TSG-F					
Service Charge	per Month	$955.37	$6.41	$6.84	$962.21
Demand Charge	per Demand therm	2.3306	0.0038	0.0040	2.3347
Distribution Charges	per therm	0.089084	0.000147	0.000157	0.089241
TSG-NF					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge 0-50,000	per therm	0.104741	0.000447	0.000476	0.105218
Distribution Charge over 50,000	per therm	0.104741	0.000447	0.000476	0.105218
CIG					
Service Charge	per Month	211.29	0.95	1.01	212.30
Distribution Charge 0-600,000	per therm	0.094412	0.000414	0.000441	0.094854
Distribution Charge over 600,000	per therm	0.083750	0.000414	0.000442	0.084191
~~**BGSS-RSG**~~					
~~Commodity Charge including Losses~~	~~per therm~~	~~0.397512~~	~~(0.000015)~~	~~(0.000015)~~	~~0.397497~~
CSG					
Service Charge	per Month	955.37	6.41	6.84	962.21
Distribution Charge - Non-Firm	per therm	0.104741	0.000447	0.000476	0.105218

*Base Distribution Charges include GSMPII changes pursuant to Docket Nos. GR21121256, GR22060409 & GR22120749.

INFRASTRUCTURE IMPROVEMENT PROGRAM CHARGE

These charges are designed to recover the revenue requirements associated with the Company's Infrastructure Improvement Programs (IIPs) in accordance with the New Jersey Board of Public Utilities' rules on IIPs, N.J.A.C. 14:3-2A.

For detail concerning individual rate class base distribution charges, see individual rate class tariff sheets.

(Charges are for illustrative purposes only and are based on the Seventh Revised Sheet No. 61 filed with the BPU on October 1, 2023)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 62
Original Sheet No. 63
Original Sheet No. 64

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 65**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for residential purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$8.08 in each month [$8.62 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge Including SUT	
$0.437491	$0.466475	per therm

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 66**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

Conservation Incentive Program Charge:

This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Societal Benefits Charge, the Margin Adjustment Charge, the Green Programs Recovery Charge, the Tax Adjustment Credit, ~~and~~ the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the Distribution Charge for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:

A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:

In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-RSG.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 67**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-RSG (BGSS-RSG) default service.

The BGSS-RSG Commodity Charge will be applied to all therms billed each month, except customers that receive Delivery Service under Special Provision (c) of this Rate Schedule where the therms used for all purposes in excess of 50 therms in any month during the Off-Peak Period shall be charged at the BGSS-RSGOP Commodity Charge.

Refer to the Basic Gas Supply Service – RSG sheets of this Tariff for the current charge for the BGSS-RSG commodity charge and the BGSS-RSGOP commodity charge.

OTHER CHARGES:

See Special Provisions (c) and (g) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 68**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill.

TERM:

Customer may discontinue delivery service upon notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) This rate schedule is available where all service is for residential purposes:

(a-1) In individual residences and appurtenant outbuildings;

(a-2) In residential premises where customer's use of gas service for purposes other than residential is incidental to the customer's residential use;

(a-3) For rooming or boarding houses where the number of rented rooms does not exceed twice the number of bedrooms occupied by the customer;

(a-4) In separately metered individual flats or apartments in multiple-family buildings;

(a-5) In multiple-family buildings of two or more individual flats or apartments where gas service is measured by one meter and is furnished to the tenants or occupants of the flats or apartments by the owner. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not;

(a-6) In multiple-family buildings of two to four individual flats or apartments where gas fired equipment serves multiple flats or apartments. Where Special Provision (c) is applicable, the applicable therms shall be multiplied by the number of individual flats or apartments, whether occupied or not.

(b) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 69**

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
(Continued)

(c) **Off-Peak Use**: Limited to customers with gas central air-conditioning equipment having a rated capacity of not less than two tons of refrigeration. For all eligible customers the Distribution Charge for the therms used for all purposes in excess of 50 therms in any month during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(d) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(e) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(f) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(g) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS's deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 70
Original Sheet No. 71

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 72**

RATE SCHEDULE GSG
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes where: 1) customer does not qualify for RSG and 2) customer's usage does not exceed 3,000 therms in any month. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$18.97 in each month [$20.23 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Pre-July 14, 1997 *		All Others		
Charge	Charge Including SUT	Charge	Charge Including SUT	
$0.328263	$0.350010	$0.328263	$0.350010	per therm

* Applicable to customers who have taken TPS supplied commodity service continuously since July 14, 1997.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 73**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge ~~and the Conservation Incentive Program Charge~~ will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 74**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (b), (e) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 75**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) **Off-Peak Use:** This separately metered gas service is applicable for cooling or dehumidification when supplied through a separate meter. For all eligible customers the Distribution Charge for the therms used during the Off-Peak period shall be set equal to one-half (1/2) the above Distribution Charge.

The Off-Peak period shall commence and end with the regularly scheduled meter readings in the months of April and October, respectively.

(c) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 76**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

(e) **Unmetered Service:** Unmetered service will be furnished, at the discretion of Public Service, for customer owned and installed gas lamps or other continuous burning devices. No other gas using devices shall be connected to this service. The customer shall provide, at the customer's expense, all necessary equipment and piping after the gas Service Connection. Further, the customer may be required to furnish and install, at the customer's own expense, a load-limiting device approved by Public Service, which shall be maintained by Public Service at customer's expense. Customer shall notify Public Service in writing as to changes in conditions or operation that may affect the gas consumption of the connected device(s). Public Service reserves the right to meter any and all such installations where customer does not comply with the requirements of this Special Provision.

(f) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(f-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(f-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 77**

RATE SCHEDULE GSG
GENERAL SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(g) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(h) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(i) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(j) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 78**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 79**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery service for general purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$168.50 in each month [$179.66 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$4.3754	$4.6653	per Demand Therm

Distribution Charges:

Per therm for the first 1,000 therms used in each month		Per therm in excess of 1,000 therms used in each month	
Charges	Charges Including SUT	Charges	Charges Including SUT
$0.033054	$0.035244	$0.050101	$0.053420

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Balancing Charge:

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 80**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Margin Adjustment Charge:
This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:
This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Conservation Incentive Program Charge:
This mechanism removes the Company's disincentive for promoting conservation by truing up actual usage to a baseline per customer established in its last approved rate case. Refer to the Conservation Incentive Program sheet of this Tariff for the current charge.

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit, the Conservation Incentive Program Charge, and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge ~~and the Conservation Incentive Program Charge~~ will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:
a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 81**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge.

OTHER CHARGES:

See Special Provisions (f) and (i) below.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 82**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

Balancing Use Therms:
During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by dividing customer's weather-normalized usage, adjusted for losses, for each of the most recent twelve (12) billing months by the total number of days in each billing month. Public Service may adjust customer's DCQ during the year, due to changes in customer's gas equipment or pattern of usage, or projected usage. For new customers, customer's initial DCQ will be estimated by Public Service, based upon the rating of the customer's gas equipment and expected utilization of the equipment. At the end of each billing period, Public Service will calculate the difference between customer's actual usage, adjusted for losses, and actual TPS supply for the billing period, taking into consideration any adjustments from prior months, and will adjust the DCQ for the second succeeding month by that difference divided by the total number of days in the month, provided that such adjustment will not decrease that month's adjusted DCQ to a level less than zero. Any such adjustment that would result in a particular month's DCQ being less than zero will be carried to a future month.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale, except where service is for motor vehicle fuel supplied through compression equipment.

(b) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header during the term of the Service Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 83**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

(c) Where Public Service is unable to read the meter on a regular basis, Public Service may require the installation of a remote meter reading device at the customer's expense.

(d) **Cogeneration Use:** Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(e) **Veterans' Organization Service:** Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

(e-1) Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(e-2) The customer will continue to be billed on this rate schedule. At least once annually, the Company shall review eligible customers' delivery charges under this Special Provision for all relevant periods. If the comparable delivery charges under the Residential Service (RSG) rate schedule are lower than the delivery charges under its current rate schedule, a credit in the amount of the difference will be applied to the customer's next bill.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 84**

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(f) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(g) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(h) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(i) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 85
Original Sheet No. 86

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 87**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Lamps, posts, maintenance, and firm delivery service for street lighting purposes. Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Monthly Charge Per Unit (Includes lamp, post, maintenance and firm delivery service):

Lamps Installed Prior to January 1, 1993:

	Charges	Charges Including SUT
Single–mantle lamp	$ 13.2351	$ 14.1119
Double–mantle lamp, inverted	13.2351	14.1119
Double-mantle lamp, upright	13.2351	14.1119
Triple–mantle lamp	13.2351	14.1119

Lamps Installed on or after January 1, 1993:

	Charges	Charges Including SUT
Triple–mantle lamp	$ 67.4762	$ 71.9465

Allowance for Lamp Outages:

The Monthly Charge per unit reflects an outage allowance based upon normal operating conditions. No further allowance will be made.

Distribution Charge per Therm:

Charge	Charge Including SUT
$0.053531	$0.057077

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 60 for details of these charges.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 88**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge, and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances where a customer selected TPS does not deliver sufficient quantities of gas.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, a customer's chosen TPS does not deliver the quantities of gas required, or if Public Service cannot confirm that the customer has an eligible TPS, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service-Firm.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 89**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

Basic Gas Supply Service:
Customers that do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Firm (BGSS-F) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for the BGSS-F commodity charge.

OTHER CHARGES:

See Special Provision (e) below.

BILLING DETERMINANTS:

Therms:
The number of therms used are shown below for each lamps type.

Single-mantle	0.69 therms per day
Double-mantle, inverted	0.77 therms per day
Double-mantle, upright	1.37 therms per day
Triple-mantle	0.77 therms per day

Daily Contract Quantity:
The Customer's Daily Contract Quantity (DCQ) for each month shall be calculated by Public Service for twelve (12) months by multiplying the number of days in the billing month by the above listed daily usage values in therms, adjusted for losses, for each lamp type times the number of customer lamps. If the customer has multiple lamp types then the DCQ would be the sum from all lamp types calculated in the preceding manner. Public Service may adjust customer's DCQ during the year, due to changes in the number and types of customer's lamps.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Five years; written contract required.

Customers who transfer from third party supply to Basic Gas Supply Service may be subject to renewable one year terms. Refer to Section 14 of the Standard Terms and Conditions of this Tariff for additional limitations regarding the term of Basic Gas Supply Service.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 90**

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
(Continued)

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(b) Customers who desire to purchase their gas supply from a TPS may request an enrollment package from Public Service that describes the process necessary for the customer to obtain a TPS for gas supply. This package will be provided to the customer at no charge by Public Service.

(c) The customer must contract with a TPS to arrange for deliveries to Public Service of the DCQ, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(d) The customer's TPS is required to notify Public Service of the customer's selection on or before the 10th calendar day of the month to become effective on the first scheduled meter reading date beginning with the first calendar day of the following month, and such selection shall remain in effect for the billing period, subject to the conditions of Emergency Sales Service.

(e) Upon customer return to BGSS, change in TPS or the cessation of delivery service, Public Service shall review the status of customer's imbalance between actual usage and actual TPS deliveries to the customer, less losses, and shall include such imbalances in that TPS's future delivery requirement.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 91
Original Sheet No. 92

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 93**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule since December 1, 1994, with the exception of any new customers for whom commitments by Public Service had been made prior to December 1, 1994.

APPLICABLE TO USE OF SERVICE FOR:

Firm delivery, subject to Public Service's available capacity to provide such service, where the maximum requirement for firm gas is not less than 150 therms per hour and where the customer's Third Party Supplier (TPS) and/or its agent has arranged for the delivery of gas supplies to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver the customer's purchased gas supply.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Demand Charge (Applicable in the months of November through March):

Charge	Charge Including SUT	
$2.1896	$2.3347	per Demand Therm

Distribution Charges:

Charge	Charge Including SUT	
$0.083696	$0.089241	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Margin Adjustment Charge:

This charge shall credit net revenue associated with Rate Schedule Non-Firm Transportation Gas Service (TSG-NF) to customers on Rate Schedules RSG, GSG, LVG, SLG and TSG-F. Refer to the Margin Adjustment Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 94**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge, the Margin Adjustment Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the requirement of the Third Party Supplier Requirement portion of this Tariff, Public Service may supply the deficiencies as Emergency Sales Service. Public Service may supply gas commodity service to such customer as Emergency Sales Service unless and until customer selects another TPS.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm sales obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supply Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Demand Therms:
The Demand Therms shall be the highest winter month (November through March) average daily usage calculated for the current month and all winter months occurring during the preceding 11 months. The customer's winter month average daily usage shall be determined for each billing month during that period of November through March by dividing billed therms, used by the customer, by the actual number of days in the billing period.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 95**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be restricted to the maximum annual, daily and hourly requirements, and the location and equipment specified in the service agreement. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement.

(b) The customer must contract with a TPS to arrange for deliveries to Public Service of its daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

Details for third party supply can be obtained by referring to Section 14 – Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff.

(c) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(d) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(e) Service under this rate schedule is not available for resale.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 96**

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
(Continued)

(f) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205(a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 97
Original Sheet No. 98

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 99**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Interruptible delivery for general purposes where the maximum requirement for interruptible gas is not less than 150 therms per hour and where the customer has the installed capability to utilize an alternate type of fuel, except as provided for in Special Provision (a). Customers may either purchase gas supply from a Third Party Supplier (TPS) or from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.098680	$0.105218	per therm

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Public Service may reduce the Distribution Charge at the beginning of the month and/or during the month to reflect market conditions.

This charge does not apply to gas sold to customer by Public Service pursuant to Special Provision (d).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:

This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

COMMODITY CHARGES:

A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 100**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

b) Public Service through its Basic Gas Supply Service default service. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
Customers with a maximum requirement of less than 2,000 therms per hour and who~~that~~ do not receive gas supply from a TPS will be supplied under the Basic Gas Supply Service-Interruptible (BGSS-I) default service, which will be applied to all therms billed each month. Refer to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

OTHER CHARGES:

See Special Provisions (d) and (e).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 101**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

TERM:

Unless otherwise agreed upon by customer and Public Service**,** one year from the commencement date specified in the service agreement required by Special Provision (a) and successive one-year periods thereafter. Service may be terminated by either customer or Public Service by providing no less than one month's notice prior to the expiration of the term.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum annual, daily, and hourly requirements, and the location and equipment specified. Upon request by customer, Public Service may deliver available volumes of gas supply, adjusted for losses, in excess of the maximum requirements, for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in the service agreement. Attached to the service agreement will be a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(b) Customers who were taking service under former Rate Schedule ISG Special Provision (b) on January 8, 2002 will be provided service under this rate schedule and are exempt from the minimum connected load requirement of 150 therms per hour.

(c) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(d) If customer does not discontinue the use of gas after notification pursuant to Special Provision (c) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 102**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (c), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (c) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(e) If a customer requests a change from this delivery rate schedule to firm service firm service will be available on a prospective basis subject to the availability of supply and delivery capacity, If a customer switches to firm service, they must remain on firm service for at least one year.~~during the months of November through March, the customer will be switched to that firm rate schedule, subject to the availability of supply and delivery capacity, retroactive to November 1 of the current winter period. If the customer was assessed charges under Special Provision (d) and such switch to firm service is approved by PSE&G, the charge for any gas in excess of the one hour's maximum requirement shall be lowered from ten times to one times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in Gas Daily on the table "Final Daily Price Survey" for each therm of gas used by the customer.~~ If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.

(f) Customer may be required to make a deposit toward the total cost of facilities which Public Service installed to provide service if gas equipment or applications were, in the prior five-year period, previously served under Rate Schedules RSG, GSG, LVG or TSG-F for the same customer. Such deposit will be determined as if such gas equipment or applications had been served under Rate Schedule TSG-NF for the entire period served under the above firm rates, utilizing the deposit calculations in existence at the time the customer began service.

(g) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Except as provided in Special Provision (a) customer has installed and maintains complete and adequate standby equipment and fuel supply for operation with another fuel when the gas supply is interrupted.

(j) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. If the customer obtains gas supply from a TPS, these personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff. If the customer obtains gas supply from Public Service under BGSS-I default service, Public Service may establish similar operational coordination requirements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 103**

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
(Continued)

(k) Service under this rate schedule is not available for resale.

(l) Cogeneration Use: Applicable to separately metered service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utilities Regulatory Policies Act of 1978 whose cogeneration equipment meets the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b). Customer must document that qualifying status has been granted by the Federal Energy Regulatory Commission.

Service to a qualifying cogeneration facility as set forth above may be exempt from taxes as set forth in Section 15 of the Standard Terms and Conditions.

(m) Military Service: United States Department of Defense Military bases may apply for service under this special provision. Under this special provision: 1) a customer must choose to receive gas supply from a TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements of this Tariff; 2) delivery service will not be interrupted with respect to the customer's gas that is delivered to Public Service by the customer's TPS on any day; 3) all service for each service location must be through a single meter; 4) the requirements for an alternate fuel shall not apply; and 5) in lieu of the annual alternate fuel certification required by each November 1st as described in Special Provision (a) above, the customer is required to submit a certification by each November 1st that it has a contract with a TPS to supply its gas requirements each day through the end of the following March.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SELECTING THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(n) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(o) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customer can change TPSs effective only on the first day of the month.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS

Original Sheet No. 104
Original Sheet No. 105
Original Sheet No. 106

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 107**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE

This rate schedule is limited to customers continuously taking service under this rate schedule or former Rate Schedule CEG since January 8, 2002, with the exception of any new customers for whom commitments by Public Service had been made prior to January 9, 2002.

APPLICABLE TO USE OF SERVICE FOR:

Interruptible gas delivery and supply service for the sequential production of electrical energy and useful thermal energy from the same fuel source by a Qualifying Facility, as defined in Section 201 of the Public Utility Regulatory Policies Act of 1978, and regularly meeting the efficiency standards set forth in Chapter 18 of the Code of Federal Regulations, Sections 292.205 (a) and (b) and where the combined nameplate-rated capacity of the generation equipment is not less than 1.5 megawatts and not greater than 20 megawatts. This size limitation shall not apply to customer's Qualifying Facilities receiving service under this rate schedule prior to January 1, 1993.

DELIVERY CHARGES:

Service Charge:

$199.11 in each month [$212.30 including New Jersey Sales and Use Tax (SUT)].

Distribution Charges:

Charge	Charge including SUT	
$0.088960	$0.094854	per therm for the first 600,000 therms used in each month.
$0.078960	$0.084191	per therm in excess of 600,000 therms used in each month.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

This charge does not apply to gas sold to customers by Public Service pursuant to Special Provision (c).

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Societal Benefits include: 1) Social Programs, 2) Demand Side Management Programs, 3) Manufactured Gas Plant Remediation, 4) Consumer Education, and 5) Universal Service Fund. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge.

Tax Adjustment Credit:

This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, SVP – Finance, Planning & Strategy – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 108**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

COMMODITY CHARGES:

Customers taking service under this rate schedule are required to receive their commodity service from Public Service. Refer to the BGSS-CIG Commodity Charge sheet of this Tariff for the current charge.

Other Charges:
See Special Provisions (c) and (n).

BILLING DETERMINANTS:

Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factors which appear on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

One year and thereafter until terminated by five days' notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer must certify that qualifying status has been granted by the Federal Energy Regulatory Commission and will be required to sign a service agreement. Service will be restricted to the maximum annual and hourly requirements, and the location and equipment specified in that service agreement. Upon request by customer, Public Service may deliver available volumes of gas in excess of the maximum hourly requirement for limited periods. Such deliveries shall not be deemed to constitute a change in the requirements specified in that service agreement.

(b) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 109**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(c) If customer does not discontinue the use of gas after notification pursuant to Special Provision (b), the Commodity Charge shall be $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a per therm quantity not to exceed one hour's maximum requirement per day of interruption.

The charge for all additional gas used shall be ten times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey." This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

If a customer persistently does not discontinue the use of gas after notification pursuant to Special Provision (b), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under an interruptible rate schedule. Applicable firm service will be available on a prospective basis, subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to supply gas at any time following notice pursuant to Special Provision (b) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

If a customer requests a change from this delivery rate schedule to firm service, firm service will be available on a prospective basis subject to the availability of supply and delivery capacity. If a customer switches to firm service, they must remain on firm service for at least one year, ~~during the months of November through March, the customer will be switched to that firm rate schedule, subject to the availability of supply and delivery capacity, retroactive to November 1 of the current winter period. If the customer was assessed charges under this Special Provision and such switch to firm service is approved by PSE&G, the charge for any gas in excess of the one hour's maximum requirement shall be lowered from ten times to one times the highest price of the "Absolute" daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Final Daily Price Survey" for each therm of gas used by the customer. If necessary, the customer will also be charged for system reinforcement, in accordance with Section 3, Charges for Service of the Standard Terms and Conditions of this Tariff.~~

(d) Metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(e) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes.

(f) Service will not be supplied under this rate schedule and any other gas rate schedule for the same process or operation at the same location except as specified under Special Provision (i).

(g) Public Service agrees that service under this rate schedule will not be interrupted unless service to the TSG-NF customers receiving BGSS-I default service has already been interrupted.

(h) Gas supplied under this rate schedule is limited to a quantity equal to the lesser of either 0.150 therms for each net kilowatt-hour of cogenerated electric generation fueled by gas or the quantity of gas actually consumed by the cogeneration facility when operated in a cogeneration mode as determined by Public Service. Net cogenerated electric generation is defined as generation output less energy used to run the cogeneration facility's auxiliary equipment. Auxiliary equipment includes, but it is not limited to, forced and induced draft fans, boiler feed pumps and lubricating oil systems.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 110**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(i) Gas supplied in excess of the quantity described in Special Provision (h) will be billed under an applicable rate schedule as determined by Public Service except as specified under Special Provision (c).

(j) Net cogenerated electric generation fueled by natural gas will be determined each month as follows:

(j-1) For facilities which burn two or more fuels simultaneously for cogeneration, net cogenerated electric generation will be allocated between such fuels on the Btu input of each fuel.

(j-2) For facilities which change fuel usage between gas and an alternate fuel for cogeneration, net cogenerated electrical generation fueled by gas will be based on meter readings taken by the customer at the time the fuel change occurs or the portion of the allocated amount determined in Special Provision (h) prorated by the number of hours or days that the customer used gas.

(k) Public Service, at its sole discretion, may utilize readings from customer or Company-owned meters to determine the quantity of gas to which this rate schedule is applicable in lieu of the allocation specified in Special Provision (j-1). The customer shall make available, and Public Service shall have the right to read, inspect and/or test such customer-owned meters during normal working hours. Additional gas, electric and/or useful thermal output meters required to determine the amount of gas to which this rate schedule is applicable will be installed, owned and operated by Public Service. However, Public Service may, at its sole option, use calculated or estimated data to determine such gas usage.

(l) Customer is required to file a monthly report to Public Service containing the total amount of kilowatt-hours produced by the cogeneration facility.

(m) Service under this rate schedule is not available for resale.

(n) **Extended Gas Service:** Gas service under this Special Provision is limited to customers having an executed service agreement for this Special Provision. Customer's executed service agreement must be received by Public Service no later than November 15th for service to be provided for the upcoming winter season. Approval of the customer's request will be provided on a case by case basis so as not to adversely impact Public Service's distribution system. When service under this Rate Schedule is interrupted, service under this Special Provision will be supplied at Public Service's option. When Extended Gas Service is offered by Public Service, the following provisions shall apply:

(n-1) In lieu of the Therm Charge hereinbefore set forth, the following charges shall apply: 1) a Special Delivery Charge which, based upon the marketability of this gas, would fall between a floor price of $0.100 ($0.107 including SUT) per therm and a ceiling price of $0.180 ($0.192 including SUT) per therm for each therm of Extended Gas Service supplied to the customer; and 2) a Commodity Charge which shall be the maximum of the "Common" range value stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Zone 6 New York for the day(s)~~the actual delivered price of propane to Public Service's BGSS supplier(s) or the highest cost gas purchased or used by Public Service's BGSS supplier(s)~~ when service under this Special Provision is offered~~, whichever is the incremental gas source~~.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 111**

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
(Continued)

(n-2) A service agreement for this Extended Gas Service shall be executed for each winter season and shall include the customer's maximum daily requirements under this Special Provision and a prepayment equal to four days of the Special Delivery Charge at a rate of $0.150 ($0.160 including SUT) per therm at the customer's maximum daily requirement. Use of gas above the maximum daily requirement, on any day for which Public Service has offered and the customer has requested Extended Gas Service, will be subject to the penalty as stated in Special Provision (c). Such prepayment shall be non-refundable unless and to the extent that Public Service does not offer customer such Extended Gas Service for at least 96 hours, during the winter season. If Public Service, offers such service for less than 96 hours, the refund shall be made on a prorated basis. In addition to such prepayment, a non-refundable application charge of $800.00 ($853.00 including SUT) shall be paid by each customer.

(n-3) Customer will be notified electronically or by phone of the Extended Gas Therm Charge at least eight hours prior to the availability of this service, or prior to a change in the Extended Gas Therm Charge~~, by facsimile machine~~. Following receipt of Public Service's notice, the customer will have two hours within which to electronically notify ~~facsimile to~~ Public Service the customer's acceptance of the Extended Gas Therm Charge for the service. If customer does not accept this service, customer must discontinue the use of gas at the time designated by Public Service, which time shall not be less than eight hours after Public Service's notice to Customer of the availability and the Therm Charge of the Extended Gas Service. Any gas usage by customer following the time designated by Public Service shall be subject to the penalty as stated in Special Provision (c).

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c.57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except section 7.6, Appliance Adjustments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112**

RATE SCHEDULE CSG
CONTRACT SERVICE

APPLICABLE TO USE OF SERVICE FOR:

Firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Public Service will review all applications to verify for completeness within 45 days of receipt. If any data is missing, Public Service will notify customer of the information needed to complete the application. Public Service reserves the right to request additional information as needed on a case by case basis. Once a request is deemed complete, Public Service will have 45 days to complete its analysis and respond to the customer. Once agreement has been reached, Public Service will forward the application to the Board of Public Utilities for review and approval. Once approved by the Board of Public Utilities, the customer agrees that the discounted rate set forth under this rate schedule will not be confidential.

Customers may purchase gas supply from a Third Party Supplier (TPS) or, for customers with a maximum requirement of less than 2,000 therms per hour, from Public Service's Basic Gas Supply Service default service as detailed in this rate schedule.

ECONOMICALLY VIABLE BYPASS

For all customers requesting this tariff service based on an economically viable bypass alternative, the customer must submit to Public Service the following minimum information but not limited to:

1. A bypass feasibility report issued by the interstate pipeline or an independent engineering consultant setting forth:
    i. Maps showing the route of the potential bypass;
    ii. Flow diagrams showing the major components of the bypass from the interstate pipeline interconnection to the customer;
    iii. Engineering studies related to the proposed cost to bypass including estimated costs for: right-of-way; regulatory approvals; material; equipment; structures; construction; overheads; contingencies and tax gross-up applicable to pipeline company facilities;
    iv. The location class, design pressure, size, length, pipe specification, yield strength and wall thickness of the bypass pipeline;
    v. Schedule of all permits from State or Federal agencies and railroads necessary for the bypass;
    vi. Project schedule;
    vii. The cost estimate classification level following AACE International Recommended Practice No.18R-97;
    viii. Statement from the interstate pipeline that the proposed interconnection is operationally viable and that the pipeline can effectuate service as requested.
2. Creditworthiness of customer.
3. Estimated annual therm usage along with all supporting assumptions and calculations.

OTHER CONSIDERATIONS

Service under this rate schedule where the customer is requesting this tariff service based on considerations other than an economically viable bypass alternative will be offered by the Company in circumstances in which it determines in its sole reasonable judgment that such rates are necessary to prevent (i) economic bypass of the Company's distribution system, or (ii) the loss of load that could otherwise be served at rates that exceed marginal costs.

Customer seeking negotiated rates under this provision must provide the Company: (i) such information as the customer deems relevant to its request; (ii) such information as the Company may require given the particular circumstances.

In determining whether to offer individually negotiated rates, terms or conditions under this provision to a particular customer, the Company will consider all relevant information provided by the customer and make a judgment as to whether or not the negotiated rates are necessary to prevent an economic bypass or the loss of load that could otherwise be served at rates that exceed marginal costs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112A**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

ECONOMICALLY VIABLE BYPASS
DELIVERY CHARGES:

Service Charge:

$902.42 in each month [$962.21 including New Jersey Sales and Use Tax (SUT)]

Distribution Charge:

Net Alternative Delivery Cost multiplied by the applicable Net Alternative Delivery Cost Factor divided by the Contracted Monthly Therms rounded to the nearest $0.000000 per therm.

Distribution charges include Infrastructure Improvement Program Charges (IIP). Refer to Tariff Sheet 61 for details of these charges.

Maintenance Charges:

Equals the Alternative Delivery Cost multiplied by the applicable Alternative Delivery Cost Factor divided by the Contract Monthly Therms rounded to the nearest $0.000000 per therm.

Plus any customer site-specific ongoing or continuing cost not directly related to the operation, maintenance or inspection of the customer's planned by-pass pipeline. This shall include, but not be limited to, periodic payments for rights-of-way, easements, pipeline cost differentials, permits or other such costs. These charges shall be expressed on a monthly levelized basis over the term of service.

Public Service will also take into consideration any operational or deliverability differences that would be reasonably expected between the pipeline and/or service over Public Service's distribution system in determining Delivery Charges. In no event shall the Delivery Charges be lower than an amount sufficient to generate a return on the capital investments made by Public Service and recovery of marginal and embedded costs, including depreciation, to provide service to the customer over the term of each CSG agreement.

Balancing Charge:

Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

Charge	Charge Including SUT	
$0.091830	$0.097914	per Balancing Use Therm

Societal Benefits Charge:

This charge shall recover costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by government. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Societal Benefits Charge. Refer to the Societal Benefits Charge sheet of this Tariff for the current charge and applicable exemptions.

Green Programs Recovery Charge:

This charge is designed to recover the revenue requirements associated with the PSE&G Green Programs as approved by the Board. In appropriate circumstances, the Board of Public Utilities may approve a discount from the Green Programs Recovery Charge. Refer to the Green Programs Recovery Charge sheet of this Tariff for the current charge and applicable exceptions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112B**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Tax Adjustment Credit:
This mechanism is designed to return net tax benefits from the Tax Cuts and Jobs Act of 2017, and other income tax related adjustments to customers. The charge will be reset on an annual basis. Interest at the weighted average of the interest rates on PSE&G's commercial paper and bank credit lines utilized in the prior month will be accrued monthly on any under or over recovered balances. The interest rate shall be reset each month. Refer to the Tax Adjustment Credit sheet of this Tariff for the current charge.

~~The Tax Adjustment Credit will be combined with the distribution charge for billing.~~

Distribution Adjustment Charge:
This charge is designed to recover Board-approved costs. Refer to the Distribution Adjustment Charge sheet of this Tariff for the current charge.

The Tax Adjustment Credit and the Distribution Adjustment Charge will be combined with the distribution charge for billing.

The Societal Benefits Charge and the Green Programs Recovery Charge will be combined for billing.

OTHER CONSIDERATIONS
DELIVERY CHARGES:
The Delivery Charges shall be set to be sufficient to recover revenues in excess of marginal costs for Public Service to provide service to the customer under this rate schedule. Delivery Charges will be based on agreement reached with Public Service and approved by the Board of Public Utilities.

COMMODITY CHARGES:
A customer may choose to receive gas supply from either:

a) A TPS who has agreed to the terms and conditions of the Third Party Supplier Requirements portion of this Tariff, or
b) For customers with a maximum requirement of less than 2,000 therms per hour, Public Service through its Basic Gas Supply Service default service. Such supply service may be either firm or interruptible. Public Service may also supply Emergency Sales Service in certain instances as indicated below.

Third Party Supply:
A customer that receives gas supply from a TPS will be charged for gas supply according to any agreement between the customer and the TPS. The customer will not be charged for commodity by Public Service, except as provided for in Emergency Sales Service below.

Emergency Sales Service:
Emergency Sales Service is only available for customers with a maximum requirement of less than 2,000 therms per hour.

In the event that, during any month, if Public Service cannot confirm that the customer has an eligible TPS, or if the TPS no longer satisfies the Third Party Supplier Requirements of this tariff, Public Service may supply the deficiencies as Emergency Sales Service.

Emergency Sales Service will be offered at the sole discretion of Public Service, after taking into consideration its other firm supply obligations. Public Service reserves the right to curtail service to any customer if deliveries from customer's TPS pursuant to Third Party Supplier Requirements are curtailed.

If a customer is receiving Emergency Sales Service and does not wish to designate a TPS for future deliveries or customer, for any reason, no longer desires to receive gas supply from a TPS, the customer may receive gas supply pursuant to Public Service's Basic Gas Supply Service.

The conditions under which Emergency Sales Service will apply are detailed in Section 14 - Third Party Supplier Service Provisions of the Standard Terms and Conditions of this Tariff, and the charges for this service are defined on the Emergency Sales Service sheet of this Tariff.

Basic Gas Supply Service:
A customer with a Maximum Requirement of less than 2,000 therms per hour that does not receive gas supply from a TPS will be supplied, at the customer's option, under either the Basic Gas Supply Service – Firm (BGSS-F) default service or the Basic Gas Supply Service-Interruptible (BGSS-I) default service as applicable based on whether Customer is being provided firm or interruptible service pursuant to this Rate Schedule. Refer to the Basic Gas Supply Service – Firm sheet of this Tariff for the current charge for BGSS-F commodity charge

or to the Basic Gas Supply Service – Interruptible sheet of this Tariff for the current charge for BGSS-I commodity charge.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112C**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

OTHER CHARGES:
See Special Provision (f).

MINIMUM ANNUAL DISTRIBUTION CHARGE:
If customer's annual usage is less than 50% of the customer's Contract Monthly Therms multiplied by 12, then the customer will be billed for the difference between the actual annual therms and 50% of the customer's Contract Monthly Therms multiplied by 12 and then multiplied by the Distribution Charge. The Minimum Annual Distribution Charge, if applicable, will be billed at the end of the customer's annualized period. This charge applies to both Economically Viable Bypass customers and Other Consideration customers.

BILLING DETERMINANTS:
Therms:
The number of therms used shall be determined by multiplying the number of hundred cubic feet used by the conversion factor which appears on every bill. The conversion factor used for the "therm multiplier" shall be on the basis of the actual heating value of the gas used.

Balancing Use Therms:
Applicable only if the customer is provided Public Service's Basic Gas Supply Service – Firm (BGSS-F) default service.

During each of the billing months of October through May, if the average daily usage of gas in any month exceeds the average daily usage during the preceding billing months of June through September, the therms used in such month in excess of the product of the average daily usage in the preceding months of June through September times the number of days in the billing month shall be the Balancing Use Therms and subject to the Balancing Charge. For new customers and for customers who install additional gas burning equipment, the average daily usage in the preceding June through September time period to be used in the above calculation shall be estimated by Public Service.

Contract Monthly Therms:
Estimated annual therm usage (see Item 3, Tariff Sheet 112) determined as reasonable by Public Service divided by 12 and rounded to the nearest therm.

Alternative Delivery Cost:
a) For Firm Delivery Service: The estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline.
b) For Interruptible Delivery Service: The sum of 90% of the estimated total up-front cost of the customer's bypass plan, based on a detailed cost estimate provided by the applicable interstate pipeline, plus 10% of the incremental installed cost for Public Service to provide interruptible delivery service as estimated by Public Service.

Net Alternative Delivery Cost:
The Net Alternative Delivery Cost is equal to the Alternative Delivery Cost net of any customer contribution made to Public Service to provide service under this Rate Schedule without Public Service tax gross-up effects.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112D**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

Distribution Charge Factor: per $ of Net Alternative Delivery Cost

Term	Monthly Factor	Monthly Factor Including SUT
5 Years	$0.025583	$0.027278
10 Years	0.015773	0.016818
20 Years	0.010716	0.011426

Maintenance Charge Factor: per $ of Alternative Delivery Cost

Term	Monthly Charge	Monthly Charge Including SUT
5 Years	$0.000262	$0.000279
10 Years	0.000276	0.000294
20 Years	0.000300	0.000320

TERMS OF PAYMENT:

Payment is due within 15 days after the postmark date, or email date for customers who have opted for paperless billing, of the outstanding bill and subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Service to a body politic will not be subject to a late payment charge.

TERM:

Up to twenty years from the commencement date specified in the service agreement required by Special Provision (a), which length to be determined by agreement of the parties or, in the case of an economically viable physical bypass, based on the length of financing offered by the interstate pipeline company. The Distribution Charge and the Maintenance Charges as of the commencement date will remain unchanged for the term of the service agreement. The customer may terminate service by providing no less than one month's notice. Customers shall be required to make a termination payment for all such service terminated prior to the end of the Term equal to 50% of the sum of the Distribution Charge multiplied by the Contract Monthly Therms multiplied by the number of months remaining for the term of the service agreement. The termination payment shall be due to Public Service upon the date the termination becomes effective pursuant to the customer's notice.

SPECIAL PROVISIONS APPLICABLE TO ALL CUSTOMERS:

(a) Customer will be required to sign a service agreement and service will be restricted to the maximum daily capacity of the alternative delivery option used to determine the Monthly Distribution Charge. Deliveries in excess of the maximum specified in such service agreement will require the establishment of an additional new service agreement and related monthly charges, where such charges for such excess capacity shall be based upon the then current costs for such alternative delivery option and the then current pricing factor.

(b) Upon advanced written notice to Public Service, such service agreement shall be transferable to a new customer or owner of the facility at the location specified in the service agreement.

(c) Requests for a change between interruptible delivery service under this rate schedule to or from firm delivery service under this rate schedule will require the establishment of a new service agreement and new term of service based on the then current costs and pricing factor. There shall be no termination payment required related to a change from interruptible delivery service to firm delivery service under this rate schedule. A change from firm delivery service to interruptible delivery service will require a termination payment as detailed above.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112E**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

(d) For customers with a maximum requirement of 2,000 therms per hour or greater, Public Service reserves the right to discontinue delivery service at any time the total imbalance cash-out amounts unpaid, including amounts billed and amounts not yet billed, by the customer's TPS are greater than 90% of the current credit Security amount held by Public Service for the customer's TPS in accordance with Section 5 of the Third Party Supplier Requirements of this tariff.

(e) Customers with a maximum requirement of 7,500 therms per hour or greater shall designate personnel physically located at the customer's facility having operational control of the gas usage at that facility who can be directly contacted by telephone or other electronic means at any hour of any day by Public Service. These personnel shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS and shall be the only party that Public Service contacts for all operational coordination requirements including those during periods of suspension or limitation and critical periods as detailed in Sections 6.3.2 and 6.3.3 of the Third Party Supplier Requirements of this tariff.

(f) Where the customer has selected BGSS-I as their gas supply option or is supplied interruptible delivery service under this rate schedule, the following shall apply:

(f-1) The customer shall provide a signed affidavit, certifying the specific grade of fuel oil (or oils), or other alternate fuel, that can physically and legally be utilized by the installation being served. This affidavit shall be a prerequisite for receiving service under this rate schedule and shall be furnished by the customer each fall no later than November 1st. The affidavit shall include the percentage of operation which can physically and legally be served by each alternate fuel. The customer will submit, within 30 days of change in operations, a new affidavit to Public Service when such change affects its alternate fuel capability. Additionally, the Affidavit shall require customers using No. 2 Fuel Oil, No. 4 Fuel Oil, jet fuel, or kerosene to provide certification that they have, and will maintain, either seven days of alternate fuel available through on-site storage capacity or additional firm contractual supply to make-up for any storage deficiencies so as to be equal to a seven day supply. Customers providing certification that they will suspend operations during an interruption are exempt from the alternate fuel requirement. Public Service reserves the right to inspect the customer's operation as to alternate fuel capability. Customers that fail to provide an affidavit by November 1st of each year shall continue to be subject to all of the terms of this rate schedule and in addition be subject to the Demand Charge as provided for in Rate Schedule LVG.

(f-2) Upon advance notice of eight hours or more, from any hour of any day given to customer by Public Service by telephone, ~~telegram~~ or other electronic means~~wise~~, customer shall discontinue the use of gas until further notice; customer shall designate personnel who will accept such notification at any hour of any day.

(f-3) If customer does not discontinue the use of gas after notification pursuant to Special Provision (f-2) customer shall be charged $1.89 ($2.02 including SUT) per therm for an amount not to exceed one hour's maximum requirement per day of interruption. Use of this amount shall be limited to a use rate per hour not greater than 5% of customer's maximum hourly requirement.

The charge for all additional gas used shall be ten times the highest price of the daily ranges for delivery in Transco Zone 6, New York, or Texas Eastern Zone M-3 which are published in *Gas Daily* on the table "Daily Price Survey" for each therm of gas used by the customer. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 112F**

RATE SCHEDULE CSG
CONTRACT SERVICE
(Continued)

If a customer supplied under Rate Schedule BGSS-I persistently does not discontinue the use of gas after notification pursuant to Special Provision (f-2), in addition to the aforementioned penalty charge, the customer will be notified that it no longer qualifies for service under interruptible supply service Rate Schedule BGSS-I. Applicable firm supply service will be available on a prospective basis under Rate Schedule BGSS-F subject to the availability of supply and delivery capacity.

Except for pilots, however, Public Service has no obligation to deliver gas at any time following notice pursuant to Special Provision (f-2) and may discontinue completely all other deliveries of gas to customer during the period of interruption.

(g) Unless otherwise agreed to by Public Service, metering shall include a recording device, furnished by Public Service. Customer shall furnish an electrical supply for the operation of the recording device.

(h) Service supplied under this rate schedule shall be separately metered and shall not be combined with use under any other rate schedule for billing purposes. Customer shall not be eligible to receive service under this rate schedule and any other rate schedule for the same equipment or for equipment supplying a common steam header.

(i) Service under this rate schedule is not available for resale.

SPECIAL PROVISIONS APPLICABLE TO CUSTOMERS SERVED BY THIRD PARTY SUPPLIERS FOR COMMODITY SERVICE:

(j) The customer must contract with a TPS to arrange for deliveries to Public Service of their daily usage, adjusted for losses, and such TPS agrees to abide by the provisions of the Third Party Supplier Requirements. A customer is limited to one (1) TPS for gas for each account for which the customer receives delivery service.

(k) The customer's TPS is required to notify Public Service of the customer's selection prior to the last business day of the month for deliveries to commence on the first (1st) of the next month, and such selection shall remain in effect for the entire month, subject to the conditions of Emergency Sales Service. Customers eligible to receive Emergency Sales Service can change TPSs effective only on the first day of the month. Customers not eligible to receive Emergency Sales Service can change TPSs at any time in the event that their TPS fails to deliver supply.

STATE OF NEW JERSEY AUTHORIZED TAX:

The New Jersey Sales and Use Tax is applied in accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, as amended by P.L. 2016, c. 57, and is included in the appropriate charges in this rate schedule. See Section 15 of the Standard Terms and Conditions for additional details and/or exceptions.

THIRD PARTY SUPPLIER REQUIREMENTS:

TPSs are subject to the Third Party Supplier Requirements of this Tariff.

STANDARD TERMS AND CONDITIONS:

This rate schedule is subject to the Standard Terms and Conditions of this Tariff except Section 7.6, Appliance Adjustments.

~~**RATE SCHEDULE CSG PERIODIC UPDATE:**~~

~~Twenty-four months from the effective date of this rate schedule, Public Service will file an update to this rate schedule, as necessary.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 113**

RESERVED FOR FUTURE USE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 114**

THIRD PARTY SUPPLIER REQUIREMENTS

1. GENERAL

A Third Party Supplier (TPS) of natural gas is an entity that has contracted with customers of Public Service to deliver supplies of natural gas to interconnection points with Public Service's distribution system, or is a customer who is self-supplying and acting as a TPS on their own behalf in purchasing and transporting natural gas to interconnection points with Public Service's distribution system, from which Public Service may receive and physically transport and deliver on a firm basis these gas supplies to the customer pursuant to Rate Schedules RSG, SLG, GSG, LVG, TSG-F, or CSG and on an interruptible basis to customers pursuant to Rate Schedules TSG-NF or CSG. In order for an entity to qualify as a TPS it must execute an Application for Service and satisfy Public Service's credit requirements as noted herein. In order for a customer to qualify to self-supply, the Public Service customer of record for gas delivery service must be served on Rate Schedule TSG-NF or CSG and must be the same corporate entity that is purchasing and transporting the natural gas to interconnection points with Public Service's distribution system. A self-suppling customer must meet all of the TPS requirements herein, except the requirement for licensure by the Board of Public Utilities. TPSs, other than qualifying self-supplying customers, must be licensed by the Board of Public Utilities (Board).

A TPS must successfully complete all Electronic Data Interchange testing in order to enroll new customers that receive service under Rate Schedules RSG, GSG, LVG, SLG, TSG-F, TSG-NF, and CSG.

TPSs agree to abide by the Board's regulations and with N.J.A.C. 14:4 *et seq*., *Energy Competition,* including but not limited to Subchapter 7 *Retail Choice Consumer Protection.* Public Service is not responsible for the administration or the enforcement of either of the aforementioned regulations or Code.

2. CUSTOMER CONFIRMATION

By the twenty-second (22nd) of each month, for service to RSG, SLG, GSG, or LVG which is to commence on the first (1st) of the next calendar month, Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes: (1) those customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS, including their required Daily Contract Quantity (DCQ), expressed in therms; (2) former customers' applicable imbalances, expressed in therms; and (3) the TPS's Aggregate Daily Contract Quantity (ADCQ), adjusted for losses, expressed in dekatherms, equal to the sum of the DCQ's of each of the customers of that TPS. TPS will be required to notify Public Service by electronic or other means, as specified by Public Service, by the twenty-second (22nd) of the month as to any corrections or changes to their list of customers, otherwise the list will be assumed to be accurate. Public Service will only amend the list of customers and their respective DCQ's in accordance with the above procedures prior to the next month if a good faith dispute arises concerning the respective TPS's list.

Public Service will provide to each TPS by electronic or other means, as specified by Public Service, a list which includes those TSG-F, TSG-NF, and CSG customers who have requested to be served by that particular TPS and have represented that they have a contractual relationship with that TPS.

3. DELIVERY

3.1 **General:** Subject to the Force Majeure provisions in Section 7, TPS must deliver to Public Service on each day of the month at points specified on Public Service's distribution system, which points are operationally acceptable to Public Service in its sole discretion, the ADCQ for its RSG, SLG, GSG, and LVG customers and the daily or, under certain circumstances, the hourly usage of its TSG-F, TSG-NF, and CSG customers, adjusted for losses (hereinafter collectively referred to as "usage"). Failure to comply with this provision shall subject TPS to the cash-out pursuant to Sections 6.1, 6.2, and/or 6.3.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 115**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

3.2. **Warranty of Title:** TPS warrants that, at the time of delivery of gas to Public Service, it will have good title to deliver all gas volumes made available.

3.3. **Delivery Control and Possession:** After TPS delivers gas or causes gas to be delivered to Public Service at Public Service's point of interconnection with the applicable interstate pipeline, Public Service will be deemed to be in control and possession of the gas until an equivalent amount of gas, less losses, is delivered to customer at customer's Public Service meter.

3.4. **Delivery Liability:** Public Service shall in no way be liable for any errors in the calculation of the DCQ or ADCQ, nor be responsible for any additional gas costs incurred by TPS due to any error in the calculation of the DCQ or ADCQ.

3.5. **Delivery Allocation:** On each day deliveries of gas by TPS to Public Service shall be first allocated to TPS's ADCQ on such day and any remaining volume shall be allocated to TPS's TSG-F, TSG-NF, and CSG customers.

4. NOMINATION PROCEDURES

4.1. **General:** Unless otherwise provided for under section 4.3, Public Service will provide TPS(s) notice by July 1 of each year of the allocation of receipt capacity by pipeline that it expects to have available for all deliveries by TPS(s) at its city gate interconnections, based on existing contractual commitments, for the twelve (12) month period beginning the following November 1. Each TPS(s) will be allocated the receipt capacity based on the total expected firm and interruptible load versus the amount of available receipt capacity.

TPS will be credited for deliveries to Public Service on each day in accordance with the final daily volume confirmations of the interstate pipelines designated by TPS pursuant to this Sub-section.

4.2. **TPS Nomination Requirements ~~for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour~~:** TPS will be required to nominate to Public Service by electronic or other means, as specified by Public Service, the total volume it intends to deliver to Public Service for subsequent delivery, along with the interstate pipelines it intends to utilize for this delivery and any additional information required by Public Service to fully identify such deliveries. TPS shall nominate to Public Service by 2:30 p.m. Eastern Time prior to the day gas is scheduled to flow (ie. the "Gas Day", defined as the 24 hour period commencing at 10:00 AM Eastern Time). TPS will be permitted to submit requests to modify nominations after the 2:30 pm deadline for supplies for the Gas Day, which may include modifications to both pipeline contracts and volumes. Such modifications will be consistent with the prevailing NAESB protocols, of 7:00 PM Eastern Time on the day prior to the Gas Day, and 11:00 AM Eastern Time ("Intra-day 1"), 3:30 PM Eastern Time ("Intra-day 2"), and 8:00 PM Eastern Time ("Intra-day 3") during the Gas Day. Any such requests for modifications to nominations for a Gas Day must be submitted in writing and received by Public Service up until 8:00 PM Eastern Time during the applicable Gas Day. Public Service will not be obligated to accept gas which has not been nominated in accordance with this Section. In any event, Public Service may refuse any revision in the nomination made during the day of delivery for operating reasons, and if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.

Public Service will accept deliveries of gas for customers on the interstate pipelines of Transco or Texas Eastern. However, due to delivery limitations, Public Service reserves the right to require a reasonable apportionment of deliveries between Transco and Texas Eastern.

~~**4.3. TPS Nomination Requirements for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater:** TPS will be required to nominate to Public Service using Public Service's electronic bulletin board, at least 24 hours prior to the start of each day, the total volume it intends to deliver to Public Service for subsequent delivery the next day for each customer with a maximum requirement of 7,500 therms per hour and greater. Such~~

~~daily nomination may be changed by the TPS at any time up to and during the day for which the daily nomination is applicable by notification to Public Service.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 116**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

~~Public Service reserves the right to limit any revision to such daily nomination and shall not be obligated to accept any changes greater than one twenty-fourth (1/24) of the customer's maximum daily usage requirements multiplied by the number of hours remaining for the day. In any event, Public Service may refuse any revision in the nomination made during the day of delivery if, in its sole opinion, such revision is not related to the customer balancing its supplies and usage for the day.~~

~~Public Service will, for each customer provided delivery service, specify the interstate pipeline delivery point(s) at which gas supplies from a TPS shall be delivered. Normally such point(s) will be on the interstate pipeline that is in the closest proximity to each customer.~~

5. CREDIT REQUIREMENTS

5.1. **General:** Public Service's acceptance of a request for service under these Third Party Supplier Requirements is contingent upon TPS providing Security in an amount determined by~~satisfying a credit appraisal by~~ Public Service. ~~Based on consistent financial evaluation standards, each TPS may be granted, on a non-discriminatory basis, an Unsecured Credit Limit. Public Service shall perform such evaluations no less frequently than once every twelve (12) months.~~

~~If required, a~~A TPS may provide one of the following additional credit assurances to meet its Security obligation: (1) an advance cash deposit; or (2) a standby irrevocable letter of credit~~; or (3) a guarantee, acceptable to Public Service, by a parent Guarantor which satisfies the credit requirements. The total of the amounts offered by these instruments and, if applicable, the Unsecured Credit Limit, is defined as Security~~.

5.2. **Credit Amount:** The total Security at all times must be of an amount not less than the product of the TPS's Daily Requirements, expressed in dekatherms, and $70.00, plus the amount of balancing cash-out obligations outstanding to Public Service, whether billed or not billed, such total amount rounded down to the next lower multiple of $15,000. Daily Requirements is defined as the sum of the TPS's maximum month ADCQs for RSG, SLG, GSG and LVG customers and the total of the maximum month average daily usage for TSG-F, TSG-NF, and CSG customers, as stated in their respective service agreements. At any time, the maximum month's value shall be the greatest total ADCQ or average daily usage, as applicable, in the prior 12 month period (otherwise known as a rolling 12 month period).

If, at any point in time, the TPS's Daily Requirements decreases, TPS has the option to reduce the level of the Security to the product of the new Daily Requirements and $70.00, after all the outstanding obligations payable to Public Service are satisfied.

In all cases, any required increase in the level of Security must be satisfied within two (2) business days after receipt of the Public Service notice for additional Security requirements to continue service. If such Security is not posted in accordance with the foregoing, then Public Service is not required to continue service.

5.3. **Interest:** Interest, on cash deposited with Public Service as Security, will be the lower of the average Federal Funds Effective Rate (as published daily on the Federal Reserve website) for the period of time the funds are on deposit or six (6) percent. Cash deposits shall cease to bear interest upon discontinuance of service by the TPS or, if earlier, when Public Service closes the account. When the executed service agreement is terminated or when a portion of the cash deposit is returned to the TPS, such cash deposits will be returned with accrued interest upon payment or deduction of all charges and other debts that the TPS might owe Public Service.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 117**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

5.4. Failure to Deliver for Customers on Rate Schedules RSG, SLG, GSG, and LVG: In the event that, for a particular TPS, at any time, the sum of the cumulative imbalances, for non Force Majeure reasons, which Public Service has not yet received payment are underdeliveries that exceed three (3) times the ADCQ, Public Service will immediately notify the TPS via telephone, electronic~~facsimile~~, or similar means. If such underdeliveries reach five (5) times the ADCQ, the following will occur: (1) the TPS is no longer eligible for these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month; and (2) for the balance of the current month, the affected TPS's customers will be supplied natural gas by Public Service and will be billed for Emergency Sales Service pursuant to their rate schedules for their DCQ times the number of days remaining in the current month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS pursuant to Section 14.3 of the Standard Terms and Conditions or from BGSS default service pursuant to Section 14.5 of the Standard Terms and Conditions.

In order to be reinstated as an eligible TPS following an occurrence of an under-delivery event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an under-delivery event as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2. If an additional under-delivery event as described above occurs during that year period, the TPS will be ineligible for these Third Party Supplier Requirements for an additional one (1) year period.

5.5. Failure to Deliver for Customers on Rate Schedules TSG-F, TSG-NF, and CSG: In the event that, for a particular TPS, at any time, the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 70% of the current level of Security, Public Service will immediately notify the TPS via telephone, electronic~~facsimile~~, or similar means.

At this time the TPS will be given the option to increase the total amount of Security held by Public Service to the required amount as described in Section 5.2 of these TPS Requirements within two (2) business days or to provide immediate payment on outstanding amounts, whether billed or not billed, due to Public Service.

At such time the amount of obligations outstanding to Public Service, whether billed or not billed, exceed 100% of the current level of Security, the TPS is no longer eligible under these Third Party Supplier Requirements unless and until the conditions below are satisfied, but not before the first (1st) day of the following month. The affected TPS's customers eligible for Emergency Sales Service will be supplied natural gas by Public Service for their usage for the remainder of the month. Such customers will continue to be charged the Emergency Sales Service rate until TPS service commences from an eligible TPS or from BGSS default service. Delivery service to customers not eligible for Emergency Sales Service will be ceased until such customers arrange for gas supplies from an eligible TPS.

In order to be reinstated as an eligible TPS following an occurrence of event as described above, the former TPS, in addition to meeting all other applicable tariff requirements must post and maintain for a one (1) year period Security in an amount equal to two (2) times that otherwise required pursuant to Section 5.2 of these Third Party Supplier Requirements. At the conclusion of that year and assuming no additional occurrence of an event in which outstanding obligations, whether billed or not billed, exceed Security as described above, TPS's requirement regarding maintenance of the Security will be returned to that described in Section 5.2.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 118**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

If an additional event in which outstanding obligations, whether billed or not billed, exceed Security as described above occurs during that year period, the TPS will be ineligible under these Third Party Supplier Requirements for an additional one (1) year period.

6. IMBALANCE CASH-OUT PROCEDURES

6.1. TPS Imbalance Cash-out for Customers on Rate Schedules RSG, SLG, GSG, and LVG: On any day that TPS delivers a volume other than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

6.1.1. Over deliveries: On any day that TPS delivers a volume greater than the aggregate of the ADCQs, of its RSG, SLG, GSG and LVG customers, the TPS will be subject to a daily cash-out as follows:

The TPS will be cashed out each day for over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For over deliveries of the ADCQ of less than 5% the PSE&G will cash out the TPS for the excess gas at 90% the index. For over deliveries of the ADCQ greater than or equal to 5% but less than 15% PSE&G will cash out the TPS for the excess gas at 75% of the index. For over deliveries of the ADCQ greater than or equal to 15% but less than 25%, PSE&G will cash out the TPS for the excess gas at 50% of the index. For over deliveries of the ADCQ greater than or equal to 25%, PSE&G will cash out the TPS for the excess gas at 40% of the index.

6.1.2. Under deliveries: The TPS will be cashed out each day for under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

For under deliveries of the ADCQ of less than 5% PSE&G will cash out the TPS for the deficiency at 110 % of the index cost times the under delivered quantity. For under deliveries of greater than or equal to 5%, PSE&G will cash out the TPS for the deficiency at 200% of the index.

6.1.3. Balancing~~Under deliveries~~ during Critical Periods: Upon no less than eight (8) hours' notice, Public Service may on any days that it determines that its gas supply condition is critical, declare such days to be a "Critical Period." For any under deliveries by a TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will pay a charge per dekatherm at a rate equal to ten times the daily price index calculated in paragraph 6.1.1. The resulting price index shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC- approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. In addition, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs. For all over deliveries by an eligible TPS greater than two (2) percent of the ADCQ during a Critical Period, the TPS will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 119**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2. TPS Imbalance Cash-out for Customers with a Maximum Requirement of Less Than 7,500 Therms Per Hour on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for their applicable customers at the same daily rate that the aggregate of their applicable customers are utilizing gas. The Daily Cash-out Price for over- or under deliveries by a TPS for any day will be the weighted average of the higher of lower of the "Common" range values stated in the Final Daily Price Survey section of Platt's *Gas Daily* for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights for the weighted average shall be the required percentages of natural gas delivered on the Texas Eastern and Transco pipelines. Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any underdeliveries by eligible TPSs.

Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.2.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

6.2.2. Normal Daily Balancing for Over-deliveries. The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery.

.Imbalance Level Credit to TPS

0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 120**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.2.3. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~the then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

6.3. TPS Imbalance Cash-out for Customers with a Maximum Requirement of 7,500 Therms Per Hour and Greater on Rate Schedules TSG-F, TSG-NF, and CSG: TPS is responsible to deliver gas to Public Service for each of their applicable customers at the same daily rate each customer is utilizing gas. Except as provided for in Section 6.3.5 below, or as specified in the applicable TSG-NF or CSG agreement, all balancing and cash-out calculations shall be performed separately for each applicable customer. The basis for the Daily Cash-out Price for over- or under deliveries by a TPS will be the weighted average of the higher or lower of the "Common" range value(s) for Texas Eastern M-3 and/or Transco Zone 6 New York, as applicable. The weights for the weighted average shall be based upon the required delivery on the interstate pipeline(s) by the TPS, as published in Platt's *Gas Daily* on the table "Final Daily Price Survey". Under any circumstance, Public Service has the right to recover proportionately from undelivered TPSs any penalties or other charges or damages assessed on Public Service as a result of any under deliveries by eligible TPSs.

If at any time customer's TPS fails to deliver, or arrange for delivery of a quantity of gas, which is consistent with the quantity of gas being consumed by customer, Public Service, in its sole discretion, may suspend deliveries of gas to customer until such time as the delivery of gas to Public Service is equal to the quantity of gas being consumed by customer commences. Public Service, in its sole discretion, may refuse to accept any deliveries of gas which it determines to be excess to a TPS's customers' daily usage.

6.3.1. Normal Daily Balancing for Under-deliveries: The TPS will be cashed out each day for the under delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of under delivery. For any imbalance level, the total cost will be the sum of costs for all prior levels of under-delivery.

Imbalance Level	Cost to TPS
0% to < 5%	Under delivered volume (dth) < 5% * 1.0 * index
≥ 5% to < 15%	5% ≤ under delivered volume < 15% * 1.25 * index
≥ 15 % to < 25%	15% ≤ under delivered volume < 25% * 1.5 * index
≥ 25%	25% ≤ under delivered volume * 2.0 * index

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 121**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.2. Normal Daily Balancing for Over-deliveries: The TPS will be cashed out each day for the over delivered quantity of gas (in dekatherms) at cost based on an index. The index shall be the weighted average of the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day. The weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points.

PSE&G will cash out the TPS for under deliveries based upon the level of over delivery. For any imbalance level, the purchase credit will be the sum of credits for all prior levels of over-delivery

. Imbalance Level Credit to TPS

0% to < 5%	Over delivered volume (dth) < 5% * 1.0 * index
> 5% to < 15%	5% < over delivered volume < 15% * 0.75 * index
≥ 15 % to < 25%	15% ≤ over delivered volume < 25% * 0.5 * index
≥ 25%	25% ≤ over delivered volume * 0.4 * index

6.3.3. Balancing During Periods of Suspension or Limitation: If at any time any customer is consuming gas at a rate other than a uniform hourly rate or consuming gas at a rate that doesn't correspond with the customer's TPS' deliveries, and Public Service determines that in its sole judgment that the integrity of all or a portion of its gas distribution system is being jeopardized because of such action, or the interstate pipeline upon which such gas is being delivered to Public Service enforces uniform hourly take restrictions, Public Service may limit the total amount of gas delivered to a TPS's customer to the same hourly rate at which the TPS is delivering gas to the Public Service gas system.

Public Service will provide the TPS two hours' notice that it intends to suspend or limit deliveries of gas to one or more customers, except in the case of an emergency on the Public Service gas distribution system or when the interstate pipeline enforces uniform hourly take provisions, in which case the TPS shall be notified as soon as practicable. Such notice from Public Service shall indicate the action Public Service intends to take with respect to suspending or limiting deliveries to a customer, the estimated time period of such suspension or limitation, and the time when such suspension or limitation shall go into effect.

If, during such a period of suspension or limitation of service, the TPS delivers a quantity of gas that is inconsistent with such suspension or limitation, then all under deliveries by the TPS greater than two (2) percent will be cashed out at five times the Daily Cash-out Price. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

6.3.4. Balancing During Critical Periods: Upon no less than eight (8) hours' notice to the TPS, Public Service may on any day that it determines that its gas supply condition is critical, declare such days to be a "Critical Period". During such a Critical Period all under deliveries by the TPS greater than two (2) percent will be cashed out at ten times the Daily Cash-out Price. The price for under deliveries shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into New Jersey. All over deliveries of greater than two (2) percent will be cashed out at the minimum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Transco Leidy Line Receipts for that day.~~then current Commodity Charge applicable to Basic Gas Supply Service – Interruptible (BGSS-I).~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 122**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

6.3.5. Designated Personnel: The customer's designated personnel having operational control of the gas usage at that facility shall be responsible for coordinating the balancing of customer's gas consumption and deliveries by the customer's TPS. Such personnel shall be the only party that Public Service contacts for all operational coordination requirements, including those during periods of Suspension or Limitation and Critical Periods as detailed in Sections 6.3.2 and 6.3.3.

~~**6.3.6 Pooling**: A TPS who is supplying more than one facility under separate CSG and/or TSG-NF accounts, with each facility having a Maximum Requirement of 7,500 therms per hour or greater and with each facility being required to have its gas supplies delivered to the same interstate pipeline delivery point as advised by Public Service pursuant to Section 4.3, may pool gas deliveries to serve the pooled load of all those facilities on the respective pipeline. The TPS shall nominate to Public Service in accordance with Section 4.3 the total gas volume to be delivered to serve the load of the pooled facilities on the respective pipeline. That nomination shall be subject to intraday nomination changes;~~
~~provided, however, that such prospective changes may be limited to 1/24th of the cumulative maximum daily requirement of the pooled facilities for each remaining hour of the day. Daily imbalance cash-outs will be performed in accordance with Section 6.3, using the pooled gas deliveries versus the pooled gas usage for these facilities.~~

~~A TPS may designate a particular delivered gas supply or supplies to absorb any variation between the pooled gas deliveries and the actual pooled gas usage (swing service), provided that such supply or supplies are delivered under an interstate pipeline service agreement which is approved by the applicable interstate pipeline as being valid for use as a swing service, and that such supply or supplies have been scheduled with the pipeline's tariff provisions and operating procedures applicable to swing services. Prior to its initial utilization of a swing service, the TPS shall notify Public Service of its intention to do so. Such swing service shall not be effective until Public Service has confirmed with the applicable interstate pipeline that the swing service satisfies the pipeline's tariff provisions and operating procedures, and Public Service and the pipeline have established all necessary procedures and communications relating to daily scheduling, confirmations, and related activities.~~

6.4. Cash-out Billing and Payment: Public Service will ~~bill~~ invoice the TPS any cash-out costs and these charges are due within ten (10) days of the date of Public Service's invoice. Such bills will be subject to a late payment charge at the rate of 1.416% per monthly billing period in accordance with Section 8.13 of the Standard Terms and Conditions. Public Service has the right to call on Security in an amount equal to all unpaid cash out costs within 30 days of issuance of the cash-out invoice unless Public Service has agreed in writing to extend the period for repayment. Public Service will notify the TPS of the amount of the Security used and the amount of additional security that the TPS shall be required to post. The TPS is required to replenish this Security withing two (2) business days as described in Section 5.2 of these Third Party Supplier requirements.

It is the obligation of the TPS to provide Public Service with contact information for cash-out billing annually, and timely notification of any subsequent change to those billing contacts.

Notwithstanding the above, Public Service maintains the right to suspend transportation deliveries to any customer under Rate Schedules RSG, SLG, GSG, LVG, TSG-F, TSG-NF, and CSG from a particular TPS, and return such customers to BGSS, if in Public Service's sole opinion that TPS is not satisfying the TPS requirements as specified herein. Such TPS may also be disqualified from enrolling new customers.

7. FORCE MAJEURE

If an interstate pipeline that deliveries gas to PSE&G's system has declared a Force Majeure event, pursuant to the terms of that pipeline's FERC approved tariff, that substantially affects the ability of a TPS ~~will be excused from~~to deliver~~ing~~ the required ADCQ on any given day, Public Service may ~~for Force Majeure events which directly and substantially affect TPS's natural gas deliveries to Public Service. For purposes of these Third Party Supplier Requirements, a Force Majeure event will be any failure of the final pipeline delivering gas to Public Service or an upstream pipeline~~

~~feeding such pipeline, with failure having been classified as a Force Majeure event pursuant to the terms of that pipeline's FERC approved tariff.~~

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 17 GAS **Original Sheet No. 123**

THIRD PARTY SUPPLIER REQUIREMENTS
(Continued)

~~A legitimate Force Majeure event that curtails TPS's firm transportation service on an upstream pipeline that ultimately feeds a downstream pipeline, which directly and substantially affects a TPS's natural gas deliveries to Public Service, will~~ excuse a TPS from performing pursuant to Sections 6.1, 6.2 and 6.3 of these Third Party Supplier Requirements to the extent of such curtailment, and may cash-out the TPS for related under-deliveries at the higher of the (i) weighted average of the maximum of the "Common" range values stated in the Final Daily Price Survey section of Platt's Gas Daily for Texas Eastern M-3 and Transco Zone 6 New York for that day (the weights in the calculation shall be the required percentages of deliveries at the Texas Eastern M-3 and Transco Zone 6 New York delivery points), or (ii) the Company's average cost of supply for the period in question (inclusive of any pipeline penalties assessed on the Company)~~. If at such time the TPS is delivering gas to customers on other systems, the volume excused from performance on Public Service's system will be no more than a proportionate amount of the affected deliveries curtailed by the Force Majeure event~~. The TPS is responsible for supplying complete information and verifiable proof of all the particulars requested by Public Service related to any such Force Majeure exclusion. The TPS must have a firm, non-interruptible service with the affected pipeline that is covered by the Force Majeure event and must be willing to present such agreements to Public Service.

8. STANDARD TERMS AND CONDITIONS

These Third Party Supplier Requirements are subject to the Standard Terms and Conditions of this Tariff, as applicable.

BILL INSERT

NOTICE TO
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC AND GAS CUSTOMERS

Proposed Increases in Electric and Gas Charges

A Petition was filed by Public Service Electric and Gas Company ("PSE&G" or the "Company") with the New Jersey Board of Public Utilities ("Board") requesting an increase in the charges for electric and gas service. The Company's electric and gas base rates were last increased on November 1, 2018 for both electric and gas rates. Present electric and gas distribution rates will remain in effect until new rates are approved by the Board. Copies of the Petition, showing present and proposed charges for electric and gas service, may be examined at any PSE&G Customer Service Center, online at the PSE&G website at https://nj.pseg.com/aboutpseg/regulatorypage/regulatoryfilings, and at the New Jersey Board of Public Utilities at 44 South Clinton Avenue, 1st Floor, Trenton, New Jersey 08625-0350.

The rate relief requested is required to support the Company's responsibility to operate and maintain its electric distribution system and its gas distribution system in a safe, adequate, proper, and reliable manner. The Company has requested a net electric revenue increase of approximately $462 million (or an 8% total bill impact and a net gas revenue increase of approximately $364 million or an 11% total bill impact.

These increases are primarily due to capital investments that the Company has made and storm costs that the Company incurred, but for which it has not received recovery. These storm costs are proposed to be recovered through introduction of a Storm Recovery Charge ("SRC"), which will be a component of a new Distribution Adjustment Charge ("DAC"). These increases will be partially offset by increases to the Tax Adjustment Credit ("TAC").

Furthermore, the Company also requests the authority to recover gas bad debt expense in the same manner as is currently done for electric bad debt expense via the Social Programs component of the gas Societal Benefits Charge ("SBC") in lieu of including this expense in gas base rates.

Any final rate relief found by the Board to be just and reasonable may be modified and/or allocated by the Board with good and legally sufficient reasons to any class or classes of customers of the Company.

The percent increases by rate schedule proposed by the Company are shown below. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

ELECTRIC SERVICE	
Residential	10.4%
Residential Heating	7.1
Residential Load Management	1.5
Water Heating	13.8
Water Heating Storage	7.2
Building Heating	13.6
General Lighting and Power	15.7
Large Power and Lighting-Secondary	3.5
Large Power and Lighting-Primary	5.4
High Tension Service-Subtransmission	3.6
High Tension Service-High Voltage	2.1
Body Politic Lighting	7.7
Body Politic Lighting Service from Publicly Owned Facilities	6.0
Private Street & Area Lighting	7.6

GAS SERVICE	
Residential	14.8%
General	19.3
Large Volume	13.6
Street Lighting	0.4
Firm Transportation	13.2
Non-Firm Transportation	7.6
Cogeneration Interruptible	7.9

BILL INSERT

EXHIBIT P-1
SCHEDULE 5
PAGE 1 OF 2
(BACK)

The effect of this proposed increase on typical residential electric and gas bills is illustrated below:

RESIDENTIAL ELECTRIC SERVICE

If Your Average Monthly kWhr Use Is:	And Your Jun. to Sep. Average Monthly kWhr Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
137	171	$32.00	$37.31	$5.31	16.59%
275	342	59.21	66.72	7.51	12.68
548	683	113.64	125.55	11.91	10.48
650	803	134.25	147.74	13.49	10.05
1,000	1,300	205.89	225.43	19.54	9.49

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect November 1, 2023 except the currently pending TAC rate, and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.
(2) Same as (1) except includes charges proposed to take effect September 1, 2024.

RESIDENTIAL GAS SERVICE

If Your Average Monthly Therm Use Is:	And Your Dec. to Mar. Average Monthly Therm Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
17	25	$24.72	$31.25	$6.53	26.42%
33	50	40.80	49.11	8.31	20.37
54	100	62.38	72.82	10.44	16.74
85	167	93.97	107.73	13.76	14.64
100	200	108.69	124.00	15.31	14.09
153	300	162.18	183.15	20.97	12.93

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect November 1, 2023 except currently pending TAC rate, and assumes that the customer receives commodity service from Public Service Electric and Gas Company.
(2) Same as (1) except includes charges proposed to take effect September 1, 2024.

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECTRIC AND GAS CUSTOMERS

In The Matter Of The Petition Of Public Service Electric And Gas Company For Approval Of An Increase In Electric And Gas Rates And For Changes In The Tariffs For Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

Notice of Filing and Notice of Public Hearings

Docket No.

PLEASE TAKE NOTICE that, on December 29, 2023 Public Service Electric and Gas Company ("Public Service", "PSE&G", or "Company") filed a petition ("Petition") and supporting documentation with the New Jersey Board of Public Utilities ("Board" or "BPU") requesting an increase in charges for electric and gas service pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1. The Company's electric and gas base rates were last increased in November 2018. The rate relief requested is required to support the Company's responsibility to operate and maintain its electric distribution system and its gas distribution system in a safe, adequate, proper and reliable manner. The Company has requested an net electric revenue increase of approximately $462 million or an 8% total bill impact and a net gas revenue increase of approximately $364 million or an 11% total bill impact.

These increases are primarily due to capital investments that the Company has made and storm costs that the Company incurred, but for which it has not received recovery. These storm costs are proposed to be recovered through introduction of a Storm Recovery Charge (SRC), which will be a component of a new Distribution Adjustment Charge (DAC). These increases will be partially offset by increases to the Tax Adjustment Credit (TAC).

Furthermore, the Company also requests the authority to recover gas bad debt expense in the same manner as is currently done for electric bad debt expense via the Social Programs component of the gas Societal Benefits Charge (SBC) in lieu of including this expense in gas base rates.

The new proposed charges for electric customers, if approved by the Board, are shown in Tables #1a-#1c. The proposed percentage increases by electric customer class are shown in Table #2. The annual percentage increase applicable to specific customers will vary according to their applicable rate schedule and the level of the customers' usage. The approximate effect of the proposed increase on typical electric residential monthly bills, if approved by the Board, is illustrated in Table #3.

The new proposed charges for gas customers, if approved by the Board, are shown in Tables #4a-#4b. The proposed percentage increases by gas customer class are shown in Table #5. The annual percentage increase applicable to specific customers will vary according to their applicable rate schedule and the level of the customers' usage. The approximate effect of the proposed increase on typical gas residential monthly bills, if approved by the Board, is illustrated in Table #6.

Under the Company's proposal, a typical residential electric customer using 683 kWh in a summer month and 548 kWh in an average month (6,580 kWh annually) would see an increase in the average monthly bill from $113.64 to $125.55, or $11.91 or approximately 10.48%. A typical residential gas heating customer using 167 therms per month during the winter months and 85 average monthly therms (1,020 therms on an annual basis) would see an increase in the average monthly bill from $93.97 to $107.73, or $13.76 or approximately 14.64%.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

Present electric and gas rates will remain in effect until new rates are approved by the Board.

A copy of this Notice is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition is available for review online at the PSEG website at http://www.pseg.com/pseandgfilings and was provided to the New Jersey Division of Rate Counsel ("Rate Counsel"), who will represent the interests of all PSE&G customers in this proceeding. The Petition may also be viewed on the Board's website, https://publicaccess.bpu.state.nj.us, where you can search by the above-captioned docket number. The Petition and Board file may also be reviewed at the Board located at 44 South Clinton Avenue, 1st Floor, Trenton, NJ, with an appointment. To make an appointment, please call (609) 913-6298.

PLEASE TAKE FURTHER NOTICE that virtual public hearings are scheduled on the following date and times so that members of the public may present their views on the Petition.

DATE: TBD
TIMES: 4:30 p.m. and 5:30 p.m.
Join: Join Zoom Meeting
https://pseg.zoom.us/j/92846158128?pwd=czBtZHE5ZTh1Z1FveGlmSVg0R1NuQT09#success

Go to www.zoom.com and choose "Join a Meeting" at the top of the web page. When prompted, use Meeting number 928 4615 8128 to access the meeting. -or-

Join by phone (toll-free):
Dial In: (888) 475-4499
Meeting ID: 928 4615 8128

When prompted, enter the Meeting ID number to access the meeting.

Representatives from the Company, Board Staff, and Rate Counsel will participate in the virtual public hearings. Members of the public may participate by utilizing the link or Dial-In number set forth above and express their views on the Petition. To encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters and/or listening assistance, 48 hours prior to the above hearings to the Secretary at board.secretary@bpu.nj.gov.

Comments may be submitted directly to the specific docket listed above, using the "Post Comments" button on the Board's Public Document Search tool (https://publicaccess.bpu.state.nj.us/). Comments are considered public documents for purposes of the State's Open Public Records Act. Only submit public documents using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submissions, confidential information may be filed electronically via the Board's e-filing system or by email to the Secretary of the Board, Sherri L. Golden. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage, https://www.nj.gov/bpu/agenda/efiling/.

Emailed and/or written comments may also be submitted to:
Sherri L. Golden, Secretary of the Board
44 South Clinton Ave., 1st Floor
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-913-6241
Email: board.secretary@bpu.nj.gov

The proposed charges for electric delivery service are as follows:

Table # 1a - Electric Service

	RESIDENTIAL SERVICE (RS)	RESIDENTIAL HEATING SERVICE (RHS) (Closed)	RESIDENTIAL LOAD MGMT SERVICE (RLM)	WATER HEATING SERVICE (WH) (Closed)	WATER HEATING STORAGE SERVICE (WHS)
Delivery Charges					
Service Charge: $/mo.					
Service Charge	$8.05	$8.05	$13.94	--	$1.10
Distribution Charges: $/KWHR					
0-600, June-Sept	$0.081598	$0.090809	--	--	--
0-600, Oct-May	0.047793	0.048550	--	--	--
over 600, June-Sept	0.085672	0.096034	--	--	--
over 600, Oct-May	0.047793	0.029784	--	--	--
June-Sept On-Peak (1)	--	--	$0.111222	--	--
June-Sept Off-Peak (2)	--	--	0.020289	--	--
Oct-May On-Peak (1)	--	--	0.020289	--	--
Oct-May Off-Peak (2)	--	--	0.020289	--	--
Common Use (Tariff Special Provision a-4)	--	0.096034	--	-	--
All Use	--	--	--	$0.071466	0.001947
TAC: $/KWHR	($0.007744)	($0.010806)	($0.007252)	$0.000000	$0.000000
DAC: : $/KWHR	$0.001023	$0.001023	$0.001023	$0.001023	$0.0010123

Table # 1b – Electric Service

	GENERAL LIGHTING AND POWER SERVICE (GLP)	LARGE POWER AND LIGHTING SERVICE-SECONDARY (LPL-S)	LARGE POWER AND LIGHTING SERVICE-PRIMARY (LPL-P)	HIGH TENSION SERVICE SUB-TRANSMISSION (HTS-S)	HIGH TENSION SERVICE HIGH VOLTAGE (HTS-HV)	BUILDING HEATING SERVICE (HS) (Closed)
Delivery Charges						
Service Charge						
Service Charge	$8.30	$370.81	$370.81	$2,038.02	$1,834.22	$6.50
Unmetered	3.82	--	--	--	--	--
Night Use	8.30	--	--	--	--	--
Primary Alternate	--	--	37.45	--	--	--
Distribution Kilowatt Charges:$/kW						
Annual Demand	$4.9428	$4.0313	$3.1465	$1.9683	$0.8382	--
Demand June – Sept	16.4110	13.8058	14.1140	7.1152	--	--
Distribution Kilowatt-hour Charges: $/kWh						
June-Sept	$0.017602	--	--	--	--	$0.113726
Oct-May	0.004037	--	--	--	--	0.059612
Night Use	0.004037	--	--	--	--	--
All Use	--					--
TAC : $/kWh	($0.002415)	($0.001426)	($0.000849)	($0.000805)	($0.000351)	$0.000000
DAC : $/kWh	$0.001023	$0.0010123	$0.001023	$0.001023	$0.001023	$0.001023

Table # 1c - Electric Service

	BODY POLITIC LIGHTING SERVICE (BPL)	PUBLIC STREET LIGHTING SERVICE FROM PUBLICLY OWNED FACILITIES (BPL-POF)	PRIVATE STREET LIGHTING SERVICE (PSAL)
Luminaire Charges	(3)	--	(3)
Maintenance Charges	--	(3)	--
Delivery Charges			
Distribution Kilowatt-hour Charges: $/kWh			
All Use	$0.008701	$0.008936	$0.009297
TAC: $/kWh	$0.000000	$0.000000	$0.000000
DAC: $//kWh	$0.001023	$0.001023	$0.001023

Electric Service Notes:
All Charges are on a monthly basis, include all applicable taxes; and are applied on a per customer, per kilowatt, or per kilowatt-hour basis, as applicable. See Tariff for Provisions of all Rate Schedules.
(1) RLM - On-Peak Hours = 7 A.M. to 9 P.M. (EST) Mon.-Fri.
(2) RLM – Off-Peak Hours = All Other
(3) See Rate Schedules for details.

Table # 2
PROPOSED PERCENTAGE CHANGE BY CUSTOMER CLASS
FOR ELECTRIC SERVICE

Residential	RS	10.4%
Residential Heating	RHS	7.1%
Residential Load Management	RLM	1.5%
Water Heating	WH	13.8%
Water Heating Storage	WHS	7.2%
Building Heating	HS	13.6%
General Lighting & Power	GLP	15.7%
Large Power & Lighting- Sec.	LPL-S	3.5%
Large Power & Lighting- Pri.	LPL-P	5.4%
High Tension-Subtr.	HTS-S	3.6%
High Tension-HV	HTS-HV	2.1%
Body Politic Lighting	BPL	7.7%
Body Politic Lighting-POF	BPL-POF	6.0%
Private Street & Area Lighting	PSAL	7.6%

The percent increases noted above are based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect November 1, 2023, and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.

Table # 3
Residential Electric Service

If Your Average Monthly kWhr Use Is:	And Your Jun. to Sep. Average Monthly kWhr Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
137	171	$32.00	$37.31	$5.31	16.59%
275	342	59.21	66.72	7.51	12.68
548	683	113.64	125.55	11.91	10.48
650	803	134.25	147.74	13.49	10.05
1,000	1,300	205.89	225.43	19.54	9.49

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect November 1, 2023 except the currently pending TAC rate, and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.
(2) Same as (1) except includes changes proposed to take effect September 1, 2024.

Other proposed rate changes include the modifications to the TAC and introduction to the Distribution Adjustment Charge (DAC). For additional electric tariff related changes, see filing for details.

The proposed charges for gas delivery service are as follows:

Table # 4a – Gas Service

	RESIDENTIAL SERVICE RSG	GENERAL SERVICE GSG	LARGE VOLUME SERVICE LVG	STREET LIGHTING SERVICE SLG
Delivery Charges				
Service Charge: $/mo.	$13.39	$31.43	$279.20	
Demand Charge: $/Demand therm			$5.6967 (1)	
Distribution Charge: $/therm				
All Use:	$0.609410			$0.088700
Pre 7/14/97:		$0.543907 (2)		
All Others:		0.543907		
0-1,000 pre 7/14/97:			$0.157814 (2)	
Over 1,000 pre 7/14/97:			0.039763 (2)	
0-1,000 post 7/14/97:			0.157814	
Over 1,000 post 7/14/97:			0.039763	
Off Peak Dist Charge: $/therm				
All Use:	$0.304705 (3)			
Pre 7/14/97:		$0.271953 (2&3)		
All Others:		$0.271953 (3)		
Lamp Charge: $/unit/mo				
Installed Before 1/1/1993:				$16.7182
Installed on and After 1/1/1993:				$85.2336
TAC: $/therm	($0.099864)	($0.085090)	($0.040230)	($0.142830)
DAC: $/therm	$0.000522	$0.000522	$0.000522	$0.000522
SBC: $/therm	$0.064125	$0.064125	$0.064125	$0.064125

Table # 4b – Gas Service

	FIRM TRANSPORTATION TSG-F (Closed)	NON-FIRM TRANSPORTATION TSG-NF	COGENERATION INTERRUPTIBLE CIG (Closed)
Service Charge:$/mo.	$1,060.89	$1,060.89	$290.71
Demand Charge: $/Demand therm	$3.7472 (1)		
Distribution Charge: $/therm			
All Use:	$0.143235	$0.147626	
0-600,000:			$0.129645
Over 600,000:			$0.118983
TAC:$/therm	$0.000000	$0.000000	$0.000000
DAC:$/therm	$0.000522	$0.000522	$0.000522
SBC:$/therm	$0.064125	$0.064125	$0.064125

Gas Service Notes:
All charges are on a monthly basis, include all applicable taxes; and are applied on a per customer, per demand therm, or per therm basis, as applicable.
(1) Applicable in the months of November through March.
(2) Applicable to customers who have taken Third Party Supply (TPS) commodity service continuously since July 14, 1997.
(3) Off-Peak use is applicable in the months of April through October

Table # 5
PROPOSED PERCENTAGE INCREASES BY CUSTOMER CLASS
FOR GAS SERVICE

Residential Service	RSG	14.8%
General Service	GSG	19.3%
Large Volume Service	LVG	13.6%
Street Lighting Service	SLG	0.4%
Firm Transportation Gas Service	TSG-F	13.2%
Non-Firm Transportation Gas Service	TSG-NF	7.6%
Cogeneration Interruptible Service	CIG	7.9%

The percent increases noted above are based upon Delivery Rates and the Basic Gas Supply Service (BGSS) charges in effect November 1, 2023, and assumes that the customer receives commodity service from Public Service Electric and Gas Company.

Table # 6
Residential Gas Service

If Your Average Monthly Therm Use Is:	And Your Avg. Dec. to Mar. Monthly Therm Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
17	25	$24.72	$31.25	$6.53	26.42%
33	50	40.80	49.11	8.31	20.37
54	100	62.38	72.82	10.44	16.74
85	167	93.97	107.73	13.76	14.64
100	200	108.69	124.00	15.31	14.09
153	300	162.18	183.15	20.97	12.93

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect November 1, 2023 except currently pending TAC rate, and assumes that the customer receives commodity service from Public Service Electric and Gas Company.
(2) Same as (1) except includes changes proposed to take effect September 1, 2024.

Other proposed rate changes include the modifications to the TAC, introduction of the Social Programs of the gas SBC as well as the DAC. For additional gas tariff related changes, see filing for details.

Katherine E. Smith
Managing Counsel – State Regulatory

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

December 29, 2023

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. _____

Clerks of Each Municipality,
County Executives,
Clerk of Board of Chosen Freeholders and
County Administrators
in the Company's Electric and Gas Service Areas

Public Service Electric and Gas Company ("PSE&G" or "Company") has filed a Petition with the New Jersey Board of Public Utilities ("Board" or "BPU") requesting an increase in the charges for electric and gas service. A copy of the Petition is enclosed for your information.

The Company last reset rates in November 2018 for electric and gas. These increases are primarily due to capital investments that the Company has made and storm costs that the Company incurred, but for which it has not received recovery. These storm costs are proposed to be recovered through introduction of a Storm Recovery Charge (SRC), which will be a component of a new Distribution Adjustment Charge (DAC). These increases will be partially offset by increases to the Tax Adjustment Credit (TAC).

Furthermore, the Company also requests the authority to recover gas bad debt expense in the same manner as is currently done for electric bad debt expense via the Social Programs component of the gas Societal Benefits Charge (SBC) in lieu of including this expense in gas base rates.

The Company has requested an overall average electric bill increase of approximately 8% and an overall average gas bill increase of approximately 11%. Also attached is a copy of the bill insert which will be sent to each PSE&G customer with regular monthly meter readings.

Any final rate relief found by the BPU to be just and reasonable as the result of this filing, may be modified and/or allocated by the BPU in accordance with the provisions of N.J.S.A. 48:3-2 and 48:3-4, and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the average percentage change in customer bills may be higher or lower than indicated above, based upon the BPU's decision. The BPU may choose to impose a greater portion of any increase on any class or classes of customers and may exclude from increase any class or classes.

It is expected that the BPU will transmit the filing to the Office of Administrative Law for hearings on the Company's Petition. Notice of such hearings will be given in accordance with current legal notice requirements.

Very truly yours,

Attachments

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BALANCE SHEET
$ (In Thousands)

		Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Oct 31, 2023
Assets and Other Debits					
Utility Plant					
Electric Utility Plant					
101	Electric Utility Plant in Service	$ 22,406,654	$ 23,892,858	$ 24,822,664	$ 25,564,220
103	Electric Experimental Plant Unclassified	-	-	-	-
105	Electric Utility Plant Held for Future Use	20,778	22,039	34,362	36,981
106	Electric Completed Construction not classified- Electric	2,338,428	2,953,893	3,515,040	4,012,609
107	Electric Construction Work in Progress	1,710,632	1,110,644	1,184,330	1,292,585
	Total Electric Utility Plant	26,476,492	27,979,435	29,556,395	30,906,395
Gas Utility Plant					
101	Gas Utility Plant in Service	9,326,456	10,074,902	10,817,780	11,514,258
103	Gas Experimental Plant Unclassified	-	-	-	-
105	Gas Utility Plant Held for Future Use	96	96	96	96
106	Gas Completed Construction not classified	36,350	46,833	97,330	136,042
107	Gas Construction Work in Progress	30,706	39,475	90,574	124,401
	Total Gas Utility Plant	9,393,608	10,161,306	11,005,781	11,774,797
Common Utility Plant					
101	Common Utility Plant in Service	463,500	470,965	488,386	508,473
106	Common Completed Construction not classified	2,832	-	-	-
107	Common Construction Work in Progress	30,158	37,156	49,098	71,504
	Total Common Utility Plant	496,490	508,121	537,483	579,977
Property under capital leases					
101.1	Electric & Gas Property under capital leases	99,121	92,336	86,226	98,951
		99,121	92,336	86,226	98,951
	Total Utility Plant	**36,465,711**	**38,741,197**	**41,185,885**	**43,360,120**
Accumulated Provisions for Depreciation and Amortization of Electric Utility Plant					
108 & 111	Electric Utility Plant in Service	(4,342,539)	(4,748,992)	(5,244,177)	(5,562,972)
108.5	Electric Utility Plant Held for Future Use	-	-	-	-
	Total Electric Utility Plant	(4,342,539)	(4,748,992)	(5,244,177)	(5,562,972)
Gas Utility Plant					
108 & 111	Gas Utility Plant in Service	(2,413,343)	(2,469,413)	(2,517,747)	(2,565,591)
Common Utility Plant					
108 & 111	Common Utility Plant in Service	(231,877)	(265,024)	(298,968)	(310,135)
	Total Accumulated Provisions for Depreciation and Amortization of Utility Plant	(6,987,759)	(7,483,429)	(8,060,892)	(8,438,698)
	Net Utility Plant Excluding Nuclear Fuel	29,477,952	31,257,768	33,124,993	34,921,422
Nuclear Fuel					
120.1	120.1 In Process	-	-	-	-
120.2	120.2 Materials and Assemblies Stock	-	-	-	-
120.3	120.3 In Reactor	-	-	-	-
120.4	120.4 Spent	-	-	-	-
Accumulated Provisions for Amortization					
120.5	120.5 Nuclear Fuel	-	-	-	-
	Net Nuclear Fuel	-	-	-	-
	Net Utility Plant	**29,477,952**	**31,257,768**	**33,124,993**	**34,921,422**
Other Property and Investments					
121	Nonutility Property	3,264	3,264	3,264	2,870
122	Accumulated Provision for Depreciation & Amortization of Nonutility Property	(954)	(1,037)	(1,121)	(785)
123 & 123.1	Investments in Associated & Subsidiary Companies	45,054	44,904	44,754	44,641
124	Other Investments	222,261	180,750	143,341	120,522
125-8	Special Funds	51,397	42,906	32,196	29,031
175	Long-Term Portion of Derivative Assets	-	-	-	-
	Total Other Property and Investments	321,023	270,787	222,434	196,279

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BALANCE SHEET
$ (In Thousands)

		Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Oct 31, 2023
	Current and Accrued Assets				
131	Cash	$ 153,926	$ 43,715	$ 54,792	$ 19,212
132-4	Special Deposits	28,826	44,464	48,324	42,844
135	Working Funds	-	-	-	-
136	Temporary Cash Investments	50,000	250,000	165,000	0
141-3	Notes and Accounts Receivable	1,188,721	1,362,113	1,385,656	1,071,909
144	Accumulated Provision for Uncollectible Accounts - Credit	(205,887)	(336,497)	(339,434)	(280,722)
145-6	Receivables from Associated Companies	16,451	16,411	16,403	62,949
151-5	Materials and Supplies (incl. 163)	217,173	233,065	307,024	472,440
158	Allowances	-	-	-	-
164	Gas Stored Underground - Current	-	-	-	-
165	Prepayments	3,032	8,195	6,110	106,285
171	Interest and Dividends Receivable	-	-	-	-
172	Rents Receivable	11,766	12,405	12,447	2,161
173	Accrued Utility Revenues	238,883	228,766	338,559	183,476
174	Miscellaneous Current and Accrued	15,665	10,824	4,661	33,550
175	Current Portion of Derivative Instrument Assets	-	-	-	-
	Total Current and Accrued Assets	1,718,555	1,873,462	1,999,541	1,714,103
	Deferred Debits				
181	Unamortized Debt Expense	61,882	66,066	66,714	75,601
182	Unrec'd Plt and Reg Costs and Other Reg Assets	4,242,055	3,981,137	4,800,054	5,228,928
183	Preliminary Survey and Investigation Charges	26,603	26,296	27,971	29,314
184	Clearing Accounts	3	0	2	4
185	Temporary Facilities	-	-	-	-
186	Miscellaneous Deferred Debits	35,489	29,901	32,748	36,449
188	Research and Development Expenditures	-	-	-	-
189	Unamortized Loss on Reacquired Debt	36,066	29,951	23,854	20,292
190	Accumulated Deferred Income Taxes	844,276	787,155	698,717	579,236
	Total Deferred Debits	5,246,374	4,920,507	5,650,060	5,969,824
	Total Assets and Other Debits	**$ 36,763,904**	**$ 38,322,524**	**$ 40,997,027**	**$ 42,801,628**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BALANCE SHEET
$ (In Thousands)

		Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Oct 31, 2023
	Liabilities and Other Credits				
	Proprietary Capital				
201	Common Stock Issued	$ 892,260	$ 892,260	$ 892,260	$ 892,260
204	Preferred Stock Issued	-	-	-	-
207	Premium on Capital Stock	-	-	-	-
208	Donations from Stockholders	2,155,903	2,155,903	2,155,443	2,155,443
210	Gain on Resale or Cancellation of Reaquired Capital Stock	-	-	-	-
211	Miscellaneous Paid-In Capital	-	-	-	-
215	Appropriated Retained Earnings	-	-	-	-
216	Unappropriated Retained Earnings	10,111,424	11,550,226	12,658,335	13,870,710
216.1	Unappropriated Undistributed Subsidiary Earnings	(28)	(178)	(328)	(441)
219	Other Comprehensive Income	2,555	615	(4,589)	(5,794)
	Total Proprietary Capital	13,162,115	14,598,826	15,701,122	16,912,179
	Long-Term Debt				
221	221 Bonds	10,999,381	11,890,001	12,790,001	13,765,001
223	223 Advances from Assoc. Co.	-	-	-	-
225	225 Unamortized Premium on Long-Term Debt	-	-	-	-
226	226 Unamortized Discount on Long-Term Debt	(28,838)	(29,015)	(27,768)	(28,075)
	Total Long-Term Debt	10,970,543	11,860,986	12,762,232	13,736,926
	Other Non-Current Liabilities				
227-9	Other Non-current Liabilities	1,221,584	609,827	775,001	620,133
244	Long-Term Portion of Derivitive Instrument Liablilities	-	-	-	-
230	Asset Retirement Obligation	313,805	362,845	383,821	378,712
	Total Other Non-Current Liabilities	1,535,390	972,672	1,158,822	998,845
	Current and Accrued Liabilities				
231	Notes Payable	99,969	-	-	20,000
232	Accounts Payable	671,537	570,663	703,212	708,339
233-4	Payables to Associated Companies	470,016	408,747	475,519	238,789
235	Customer Deposits	68,225	57,770	66,649	66,612
236	Taxes Accrued	19,527	21,810	3,085	3,906
237	Interest Accrued	109,209	115,396	121,329	168,263
238	Dividends Declared	-	-	-	-
239	Matured Long-Term Debt	-	-	-	-
241	Tax Collections Payable	6,770	384	5,031	440
242	Miscellaneous Current and Accrued Liabilities	611,148	534,297	686,514	381,725
243	Obligations Under Capital leases	12,729	12,254	12,197	14,176
244	Current Portion of Derivative Instrument Liabilities	-	-	-	-
	Total Current and Accrued Liabilities	2,069,130	1,721,321	2,073,537	1,602,248
	Deferred Credits				
252	Customer Advances for Construction	58,088	69,670	87,244	89,867
253	Other Deferred Credits	349,657	294,923	275,078	270,343
254	Other Regulatory Liabilities	3,180,692	3,075,514	2,830,774	2,717,869
255	Accumulated Deferred Investment Tax Credits	128,656	118,652	108,108	98,442
281-3	Accumulated Deferred Income Taxes	5,309,633	5,609,959	6,000,110	6,374,910
	Total Deferred Credits	9,026,726	9,168,718	9,301,314	9,551,430
	Total Liabilities and Other Credits	**$ 36,763,904**	**$ 38,322,524**	**$ 40,997,027**	**$ 42,801,628**

Exhibit P-1
Schedule 9

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME ACCOUNT

	Dec 2020 * '($000)	Dec 2021 * '($000)	Dec 2022 * '($000)
400 Electric Operating Revenues	3,152,764	3,336,129	3,600,587
Electric Operating Expenses:			
401 Operation Expense	2,184,449	2,297,497	2,558,833
402 Maintenance Expense	129,665	127,580	124,436
403 Depreciation Expense	298,204	307,425	320,702
404 Amortization of Limited Term Plant	16,391	19,424	23,804
407 Amortization of Property Losses	26,767	28,165	14,249
408.1 Taxes Other Than Income Taxes	24,495	25,027	25,219
409.1 Income Taxes - Federal	75,743	89,475	(77,644)
410.1 Provision for Deferred Income Taxes	297,807	258,660	418,520
411.1 Provision for Deferred Income Taxes - Credit	(336,280)	(300,858)	(344,854)
411.103 Accretion Expense-Electric	(226)	0	0
411.4 Investment Tax Credit Adjustments (Net)	(8,160)	(9,217)	(9,796)
Total Electric Utility Operating Expenses	2,708,856	2,843,178	3,053,469
Electric Utility Operating Income	$ 443,909	$ 492,951	$ 547,118

* Electric Distribution only

	Dec-20 '($000)	Dec-21 '($000)	Dec-22 '($000)
400 Gas Operating Revenues	1,679,259	1,919,020	2,440,504
Gas Operating Expenses:			
401 Operation Expense	1,028,741	1,181,121	1,617,554
402 Maintenance Expense	49,435	33,201	38,190
403 Depreciation Expense	177,246	189,648	203,691
404 Amortization of Limited Term Plant	12,681	15,710	15,318
407 Amortization of Property Losses	30,491	38,670	30,048
407.3 Amortization of Excess cost of removal	9,747	9,747	9,747
407.4 Amortization of Excess cost of removal	0	0	0
408.1 Taxes Other Than Income Taxes	17,029	17,275	17,569
409.1 Income Taxes - Federal	13,541	(5,189)	55,177
410.1 Provision for Deferred Income Taxes	197,863	177,572	207,008
411.1 Provision for Deferred Income Taxes - Cr	(231,396)	(161,098)	(255,491)
411.4 Investment Tax Credit Adjustments (Net)	(790)	(787)	(748)
Total Gas Utility Operating Expenses	1,304,587	1,495,869	1,938,065
Gas Utility Operating Income	$ 374,672	$ 423,151	$ 502,439
Net Utility Operating Income	$ 818,580	$ 916,102	$ 1,049,556

Exhibit P-1
Schedule 10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC OPERATING REVENUES

	Year 2022
Sales of Electricity	
440 Residential Sales	$ 2,332,509
442 Commercial and Industrial Sales (a)	2,044,485
444 Public Street and Highway Lighting	73,661
448 Interdepartmental Sales	1,112
Total Sales to Customers	4,451,767
447 Sales for Resale	0
Total Sales of Electricity	0
Other Operating Revenues	
450 Forfeited Discounts	3,653
451 Miscellaneous Service Revenues	12,907
454 Rent from Electric Property *	5,140
456 Other Electric Revenues *	(988,854)
Total Other Operating Revenues	(967,154)
Total Electric Operating Revenues	$ 3,484,613

* Electric Distribution only

Note:
Includes Unmetered Sales for: (a) Private Street Lighting

GAS OPERATING REVENUES

	Year 2022
Sales of Gas	
480 Residential Sales	$ 653,428
481 Commercial and Industrial Sales	444,943
484 Interdepartmental Sales	681
Total Sales to Customers	1,099,052
Other Gas Revenues	
487 Forfeited Discounts	1,447
488 Miscellaneous Service Revenues	40,880
489.1 Revenue from Trans of Gas of Others	1,274,197
493 Rent from Gas Property	0
495 Other Gas Revenues *	5,602
Total Other Gas Revenues	1,322,126
Total Gas Operating Revenues	$ 2,421,178

* Gas Distribution only

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME ACCOUNT
12 MONTHS ENDING MAY 31, 2024 *
($000)

Operating Revenues:		
Electric	$	4,218,045
Gas		2,324,389
Total	$	6,542,434
Operating Expenses:		
Electric	$	3,749,050
Gas		1,864,434
Total	$	5,613,485
Operating Income:		
Electric	$	468,994
Gas		459,955
Total	$	928,949
Other Income and Deductions:		
Other Income	$	56,537
Other Income Deductions		(12,913)
Taxes Other Than Income Taxes		(23,059)
Total Other Income and Deductions	$	20,565
Income Before Interest Charges	$	949,514
Interest Charges		296,842
Net Income	$	652,672

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SALES BY CLASS OF BUSINESS
12 MONTHS ENDING MAY 31, 2024 *
(000)

Electric Kilowatthour Sales:	
Residential	13,420,021
Commercial	21,847,389
Industrial	3,498,950
Street Lighting	334,899
Total Sales to Customers	39,101,260
Interdepartmental	7,533
Total Electric Distribution Sales	39,108,793
Gas Therm Sales:	
Residential	1,538,177
Commercial	964,063
Industrial	84,152
Firm Transportation Service	22,704
Non-Firm Transportation Service	128,549
Cogeneration Interruptible	25,942
Contract Service Gas	684,425
Street Lighting	711
Total Sales to Customers	3,448,722
Interdepartmental	671
Total Gas Distribution Sales	3,449,393

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
12 MONTHS ENDING MAY 31, 2024 *
($000)

Electric Operating Revenue:	
Residential	2,508,564
Commercial	1,959,080
Industrial	219,388
Street Lighting	84,809
Total Revenue From Sales to Customers	4,771,841
Interdepartmental	1,127
Total Electric Operating Revenue	4,772,968
Gas Operating Revenue:	
Residential	1,562,300
Commercial	679,883
Industrial	44,702
Firm Transportation Service	3,876
Non-Firm Transportation Service	23,297
Cogeneration Interruptible	11,307
Contract Service Gas	7,720
Street Lighting	601
Total Revenue From Sales to Customers	2,333,685
Interdepartmental	384
Total Gas Operating Revenues	2,334,069

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC DISTRIBUTION OPERATING EXPENSES
12 MONTHS ENDING MAY 31, 2024 *
($000)

Production Expenses:		
Other Power Supply Expenses:		
Purchased Power	$	2,541,467
System Ctrl / Load Dispatch		5
Total Electric Distribution Power Supply	$	2,541,472
Transmission:		
Operation		0
Maintenance		0
Total Transmission		0
Distribution:		
Operation	$	52,237
Maintenance		127,615
Total Distribution	$	179,852
Customer Accounts and Information:		
Customer Accounts	$	340,964
Customer Service and Informational		160,563
Total Customer Accounts and Information	$	501,528
Sales	$	671
Administrative and General:		
Operation	$	123,738
Maintenance		0
Total Administrative and General	$	123,738
Depreciation	$	311,407
Amortization	$	39,846
Taxes other than Income Taxes	$	25,686
Income taxes	$	24,851
Total Electric Distribution Operating Expenses	$	3,749,050

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GAS DISTRIBUTION OPERATING EXPENSES
12 MONTHS ENDING MAY 31, 2024 *
($000)

Production Expenses:		
Other Power Supply Expenses:		
Purchased Power	$	1,104,641
Storage		3,033
Total Gas Distribution Power Supply	$	1,107,674
Transmission:		
Operation	$	137
Maintenance		4,087
Total Transmission	$	4,223
Distribution:		
Operation	$	97,578
Maintenance		30,247
Total Distribution	$	127,825
Customer Accounts and Information:		
Customer Accounts	$	110,421
Customer Service and Informational		137,874
Total Customer Accounts and Information	$	248,295
Sales	$	539
Administrative and General:		
Operation	$	109,075
Maintenance		0
Total Administrative and General	$	109,075
Depreciation	$	233,901
Amortization	$	44,997
Taxes other than Income Taxes	$	17,288
Income taxes:	$	(29,384)
Total Gas Distribution Operating Expenses	$	1,864,434

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADJUSTMENTS - INCREASE OR (DECREASE) - PRESENT RATES
12 MONTHS ENDING MAY 31, 2024 AS ADJUSTED*
($000)

		Electric	Gas	Total
	Test Year Distribution Operating Income	$ 468,994	$ 459,955	$ 928,949
	Tax Adjustment - N/A	-	-	-
	Adjusted Test Year Distribution Operating Income	$ 468,994	$ 459,955	$ 928,949
1	Wages	(7,362)	(6,747)	(14,109)
2	Payroll Taxes	(506)	(464)	(970)
3	Interest Synchronization (Tax Savings)	1,030	1,267	2,297
4	Pension & Fringe Benefits	(20,935)	(15,611)	(36,546)
5	COLI Interest Expense	(2,120)	(728)	(2,848)
6	Weather Normalization	(3,500)	4,424	924
7	Gains/Losses on Sales of Property	42	207	249
8	Real Estate Taxes	(617)	329	(288)
9	Insurance	(483)	(263)	(746)
10	ASB Margin	-	(14,762)	(14,762)
11	TSGNF Margin Sharing	-	(748)	(748)
12	Depreciation Rate Change	(44,544)	(71,386)	(115,930)
13	Test Year Amortization Adjustments	17,276	5,933	23,209
14	Rate Case & Management Audit Expenses	(189)	(150)	(339)
15	Energy Strong II / IAP Revenue Adjustment	30,209	-	30,209
16	BGS Admin Charge To Recon	220	-	220
17	Gas Bad Debt Adjustment	-	24,801	24,801
18	CEF-EC Amortization	(21,862)	-	(21,862)
19	CEF-EC Revenue Reduction	5,096	-	5,096
20	CEF-EV Amortization	(4,303)	-	(4,303)
21	CIP Revenue Accrual Adjustment	(62,862)	(9,597)	(72,460)
22	TAC Revenue Accrual Adjustment	(19,250)	(22,628)	(41,877)
23	Deferred Compensation & Severance	1,200	682	1,882
24	Tax Impact of Bad Debt Adjustment	(8,693)	(4,884)	(13,577)
	Total Pro-Forma Adjustments	$ (142,152)	$ (110,324)	$ (252,476)
	Total Pro-Forma Electric Distribution Operating Income	$ 326,842	$ 349,631	$ 676,473

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO FORMA OPERATING INCOME - PROPOSED RATES
12 MONTHS ENDING MAY 31, 2024 AS ADJUSTED*
($000)

	Electric	Gas	Total
Operating Income Pro Forma - Present Rates	$ 326,842	$ 349,631	$ 676,473
Adjustment:			
1. Net Increase in Revenues Resulting from proposed Rates	$ 522,084	$ 422,815	$ 944,899
2. Increase in BPU / RPA Assessments Resulting from Increase Revenue	(137,454)	(111,318)	(248,772)
2A. Uncollectibles Gas		$ -	0
3. Increase in State Income Taxes	(34,617)	(28,035)	(62,651)
4. Increase in Federal Income Taxes	24,321	19,696	44,017
Total Pro Forma Adjustments	374,334	303,158	677,493
Operating Income Pro Forma - Proposed Rates	$ 701,177	$ 652,789	$ 1,353,966

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

OPERATING INCOME, YEAR END RATE BASE AND RATE OF RETURN
12 MONTHS ENDING NOVEMBER 30, 2024 AS ADJUSTED*
($000)

	Electric	Gas	Total
Present Rates			
Operating Income	$ 326,842	$ 349,631	$ 676,473
Year-End Rate Base Nov 2024	$ 9,287,110	$ 8,646,212	$ 17,933,322
Rate of Return	3.52%	4.04%	3.77%
Proposed Rates			
Operating Income	$ 701,177	$ 652,789	$ 1,353,966
Year-End Rate Base Nov 2024	$ 9,287,110	$ 8,646,212	$ 17,933,322
Rate of Return	7.55%	7.55%	7.55%

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

NET INVESTMENT RATE BASE - AVERAGE
12 MONTHS ENDING NOVEMBER 30, 2024 AS ADJUSTED*
($000)

	Electric	Gas	Total
Plant in Service	$ 13,072,325	$ 12,883,854	$ 25,956,179
Plant Held for Future Use	495	$ 96	591
Accumulated Depreciation Reserve	(3,300,289)	$ (2,838,624)	(6,138,912)
Customer Advances	(63,736)	$ (24,945)	(88,681)
Net Plant	$ 9,708,796	$ 10,020,381	$ 19,729,177
Working Capital			
Cash (Lead/Lag)	$ 925,712	$ 605,322	$ 1,531,034
Materials and Supplies	$ 227,212	$ 67,365	$294,577
Prepayments	$ 500	$ 116	$ 616
Net Working Capital	$ 1,153,424	$ 672,803	$ 1,826,227
Deferred Taxes	(1,817,082)	(1,761,557)	($3,578,639)
Consolidated Tax Adjustment	(3,394)	0	($3,394)
IAP	(27,894)	(29,283)	($57,177)
CEF-EC	230,037	0	$230,037
CEF-EV	43,223	0	$43,223
GSMP II EXT	0	(256,132)	($256,132)
Total Rate Base	$ 9,287,110	$ 8,646,212	$ 17,933,322

* 5 Months Actual - 7 Months Estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

OPERATING INCOME, AVERAGE NET INVESTMENT
RATE BASE AND RATE OF RETURN
($000)

	Electric	Gas	Total
Present Rates			
Operating Income	$ 326,842	$ 349,631	$ 676,473
Average Net Investment Rate Base	$8,683,912	$ 8,141,925	$ 16,825,836
Rate of Return	3.76%	4.29%	4.02%
Proposed Rates			
Operating Income	$ 701,177	$ 652,789	$ 1,353,966
Average Net Investment Rate Base	$8,683,912	$ 8,141,925	$ 16,825,836
Rate of Return	8.07%	8.02%	8.05%

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE NET INVESTMENT RATE BASE

($000)

ELECTRIC RATE BASE

	Average Balance
Plant In Service	$ 12,373,228
Plant Held for Future Use	495
Accumulated Depreciation Reserve	(3,217,539)
Customer Advances	(63,736)
Net Plant	$ 9,092,448
Working Capital:	
Cash (Lead/Lag)	$ 925,712
Materials and Supplies	227,212
Prepayments	500
Net Working Capital	$ 1,153,424
Deferred Taxes	(1,777,031)
Consolidated Tax Adjustment	(3,394)
IAP	(21,355)
CEF-EC	202,229
CEF-EV	37,590
GSMP II EXT	0
Total Electric Rate Base	$ 8,683,912
	$ -

GAS RATE BASE

	Average Balance
Plant In Service	$ 12,118,917
Plant Held for Future Use	96
Accumulated Depreciation Reserve	(2,729,361)
Customer Advances	(24,945)
Net Plant	$ 9,364,708
Working Capital:	
Cash (Lead/Lag)	$ 605,322
Materials and Supplies	67,365
Prepayments	116
Net Working Capital	$ 672,803
Deferred Taxes	(1,749,268)
Consolidated Tax Adjustment	0
IAP	(14,799)
CEF-EC	0
CEF-EV	0
GSMP II EXT	(131,519)
Total Gas Rate Base	$ 8,141,925
	$ -

Exhibit P-1

Schedule 12

Public Service Electric & Gas Company

Total Utility Payments or Accruals to Affiliates

($ THOUSANDS) Net Billing

		2022
PSEG Services	$	911,393
PSEG Power		1,369,676
PSEG Long Island		(380)
PSEG Energy Holdings		(1,106)
PSEG Enterprise		301,641
Total Payments to Affiliates	$	2,581,224

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
MICHAEL P. MCFADDEN

DIRECTOR OF SALES AND REVENUE FORECASTING

December 29, 2023
P-2

TABLE OF CONTENTS

I. INTRODUCTION ..... - 1 -

II. CONTEXT FOR REQUEST AND VALUE TO CUSTOMERS ..... - 7 -

III. FACTORS DRIVING THE NEED FOR RATE RELIEF ..... - 22 -

IV. MITIGATION OF THE RATE INCREASES ..... - 36 -

A. Tax Adjustment Credit ("TAC") ..... - 37 -

B. Cost Containment Measures – O&M ..... - 39 -

C. Cost Containment Measures – A&G (Pension and Benefits) ..... - 41 -

D. Cost Containment Measures – Interest Expense ..... - 46 -

E. Appliance Service Business ..... - 46 -

F. Summary Impact of Cost Savings ..... - 47 -

V. CAPITAL STRUCTURE AND THE COST OF CAPITAL ..... - 48 -

A. Return on Equity ..... - 48 -

B. Capital Structure and Credit Ratings ..... - 51 -

VI. APPLIANCE SERVICE BUSINESS ("ASB") ..... - 60 -

VII. P&OPEB EXPENSE RECOVERY ..... - 66 -

VIII. GAS BAD DEBT RECOVERED IN SBC CLAUSE ..... - 70 -

IX. STORM COST RECOVERY ..... - 71 -

X. CONSERVATION INCENTIVE PROGRAM ("CIP") ..... - 75 -

XI. EMBEDDED COST OF DEBT RATE RECOVERY ..... - 77 -

XII. INCENTIVE COMPENSATION ..... - 82 -

XIII. DEFERRAL REQUESTS – CREDIT AND DEBIT CARD FEES AND IMPLEMENTATION COSTS FOR TIME OF USE RATES ..... - 86 -

XIV. TEST YEAR AND REVENUE REQUIREMENTS – ADJUSTMENTS TO BASE ELECTRIC AND GAS DISTRIBUTION RATES ..... - 89 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL MCFADDEN
DIRECTOR OF SALES AND REVENUE FORECASTING
PSEG SERVICES COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael P. McFadden. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by PSEG Services Corporation ("PSEG Services"), a subsidiary of Public Service Enterprise Group Incorporated ("PSEG" or "Enterprise"), as the Director of Sales and Revenue Forecasting. I have been employed by Enterprise for 15 years in a number of financial positions, primarily supporting the financial analyses and determination of revenue requirements associated with regulatory filings by Public Service Electric and Gas Company ("PSE&G, or the "Company"). Since June 2021, I have been the Director of Sales and Revenue Forecasting. My credentials are set forth in Schedule MPM-1.

Q. What are the key points in your testimony?

A. In support of PSE&G's December 2023 electric and gas base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), my testimony addresses the following key topics:

1) ***Context for Request and Value to Customers*** – I first provide some context to customer bills, explaining: a) the value the Company provides to its customers compared to peers both in cost, customer satisfaction, and reliability; b) how the

Company's bills compare to the income of median- and low-income families; c) how PSE&G's distribution costs, the subject of this proceeding, compare with those of regional peers; d) how PSE&G's total customer bill compares to that of regional peers; and e) ways customers can control their bills through proposed time of use rates and other programs the Company offers.

2) ***Factors Driving Rate Increase*** – I discuss the key drivers of the Company's rate request, which include recovery of Board-approved capital investments and deferrals, and resets of Board-approved cost recovery clauses. Major drivers include stipulated base programs and deferred investments such as those for Energy Strong II ("ES II"), the extension of the Gas System Modernization Program ("GSMP II"), the Infrastructure Advancement Program ("IAP"), the Clean Energy Future – Energy Cloud Program ("CEF-EC", or "AMI"), the Clean Energy Future – Electric Vehicle Program ("CEF-EV"), and the NJ Transit Mason Substation Project ("Mason Substation") along with other significant capital expenditures.

3) ***Mitigation of Rate Increases*** – I discuss the actions PSE&G has taken to mitigate rate increases. This includes steps taken to control costs charged to customers, a proposal to increase the flow-back of certain tax benefits to customers, and the benefits customers receive through PSE&G's Appliance Service Business.

4) ***Capital Structure and Cost of Capital*** – I discuss the Company's requested return on equity ("ROE") and capital structure that are critical both to the preservation of the Company's credit ratings and access to capital, and also to ensure just and reasonable rates. The allowed ROE and capital structure should appropriately recognize the conditions in the financial markets supporting our request.

5) ***Appliance Service Business ("ASB")*** – I address the significant benefits of the Company's ASB and the Company's request to retain 50 percent of the Gas ASB margins (revenues less expenses), the same percentage allowed on the electric side of ASB, to continue to provide this benefit to customers.

6) ***Pension & OPEB Expense Recovery*** – I discuss the Company's proposal to defer changes in pension and other post-employment benefit ("OPEB") expenses above or below the amount reflected in rates, ensuring recovery from customers, or return to customers, of cost changes outside the Company's control to ensure there are no winners or losers.

7) ***Gas Bad Debt Expense Recovery in Societal Benefits Charge ("SBC")*** – I address the Company's request, first raised in the COVID-19 proceeding,[1] to recover Gas bad debt expenses through a new social component of the SBC in the same manner as is currently done for Electric bad debt expenses.

8) ***Storm Cost Recovery Mechanism*** – I provide details on how costs for significant storm events are currently accounted for and recovered from customers, as well as PSE&G's proposal to recover those costs through a new tariff clause, the "Storm Recovery Charge." The proposal will ensure only prudently incurred costs are recovered from customers in a timely manner through a mechanism that allows for Board-approved increases or decreases outside a base rate case.

9) ***Conservation Incentive Program ("CIP") Baseline Reset*** – I explain the approved CIP mechanism for both electric and gas service and propose the new

[1] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

baseline use (for gas) or revenue (for electric) per customer as a result of this proceeding.

10) ***Embedded Cost of Debt Rate Recovery*** – I discuss the Company's proposal to defer changes in the embedded cost of debt from the rate established at the end of the test year, recognizing the current debt market conditions. The deferral mechanism would apply only to the debt component of rate base approved by the Board.

11) ***Incentive Compensation*** - I explain why recovery of incentive compensation is appropriate, integral to strong operating performance, and benefits customers.

12) ***Deferral Authority on Credit Card and Debit Card Fees and the IT Expenditures Required to Implement TOU Rates*** – I address the Company's request for deferral authority on incremental expenses the Company will incur if permitted to assume the cost of credit card payments from customers. In addition, the Company proposes to implement changes to its billing system to allow for time of use rates and requests deferral authority for the expenditures that will occur after the test year.

13) ***Test Year and Revenue Requirements*** - Finally, I support the test year and associated calculation of the Company's revenue request in this proceeding and test year and post-test year adjustments.

Q. Why is PSE&G making this base rate filing at this time?

A. This filing is being made, in part, to comply with the BPU's May 22, 2018 Order approving PSE&G's next phase of the Gas System Modernization Program ("GSMP II").[2] The

[2] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II")*, B.P.U. Docket No. GR17070776, "Decision and Order Approving Stipulation" (May 22, 2018) ("GSMP II Order").

GSMP II Order required the filing of a base rate case by no later than January 1, 2024.[3] In addition, the 'BPU's approval of the Company's ES II filing required the Company to submit a base rate case no later than December 31, 2023.[4] This filing is in compliance with those Orders and seeks approval to increase PSE&G's annual revenue requirements for both its electric and gas operations as discussed later in my testimony.

Q. What is the rate increase being sought?

A. Please see the table below for the breakdown of the net rate increase sought in this proceeding. Beyond the proposed base rate increase, the Company is also seeks: 1) recovery of storm costs through a new clause component rather than through base rates, 2) recovery of gas bad debt expense through a new component of the SBC rather than through base rates, and 3) an adjustment to flow-back certain tax benefits to customers through the Tax Adjustment Credit ("TAC").

Table 1

Rate Case Net Impact to Customers

Overall Total Revenue Impact ($M)	**Electric**	**Gas**	**Total**
Base Rates	$522	$423	$945
Tax Adjustment Credit ("TAC")	-$98	-$102	-$200
Storm Recovery Mechanism	$38	$1	$39
Gas Bad Debt in SBC	$0	$42	$42
Net Total Revenue Impact $	$462	$364	$826
Net Total Bill Impact %	8%	11%	9%

[3] Parallel requirements exist in *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, B.P.U. Docket No. EO18101115, Decision and Order Approving Stipulation (January 7, 2021) ("CEF-EC Order"), and *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, B.P.U. Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

[4] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Second Energy Strong program ("Energy Strong II")*, B.P.U. Docket Nos. EO18060629 and GO18060630, Final Decision and Order Approving Stipulation (September 11, 2019) ("Energy Strong II Order").

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision:

- Schedule MPM-1: Credentials
- Schedule MPM-2: Determination of Revenue Requirements
- Schedule MPM-3: Determination of Rate Base
- Schedule MPM-4: Weighted Average Cost of Capital
- Schedule MPM-5: Long Term Debt
- Schedule MPM-6: Revenue Factor
- Schedules MPM-7 through 18: Support for components of rate base
- Schedule MPM-19: Income Statement
- Schedules MPM-20 through 28: Support for components of the income statement
- Schedule MPM-29: *Pro-forma* Distribution Operating Income
- Schedules MPM-30 through 53: Support for *pro forma* adjustments to test year operating income
- Schedule MPM-54E and 54G: revised Electric Baseline Revenue per Customer and Gas Baseline Use per Customer amounts for the Conservation Incentive Program as a result of the revised billing determinants approved in this proceeding.
- Schedule MPM-55: Interest Rate Adjustment Mechanism

II. CONTEXT FOR REQUEST AND VALUE TO CUSTOMERS

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, all but one of the six other NJ electric and gas utilities have filed two base rate cases.

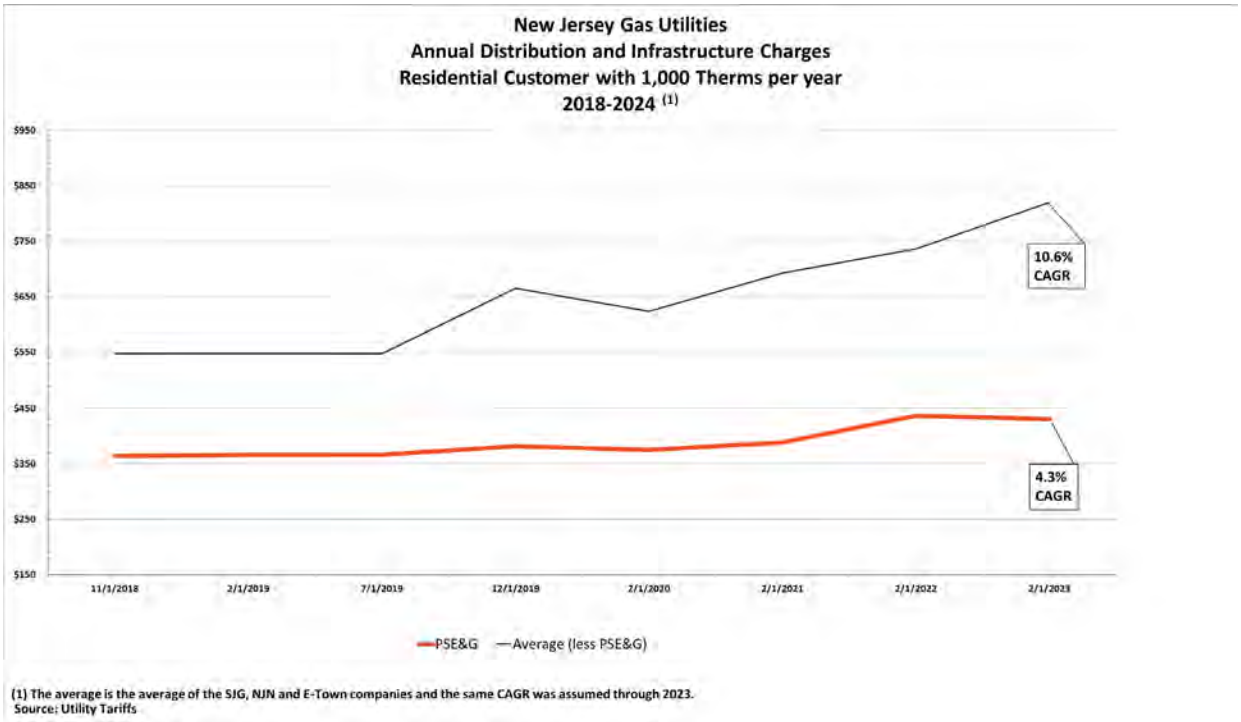
Q. How has PSE&G been able to avoid filing for a rate case until now?

A. This is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently while being good stewards of the electric and gas distribution systems and providing the funds needed to operate and maintain the systems effectively. This is achieved by regularly benchmarking Company costs, exceptional employee performance, and creating appropriate employee incentives to continue to improve upon historic success.

Q. How have PSE&G's Gas distribution rates, the subject of this proceeding, changed since the 2018 base rate case?

A. The Gas distribution rates have increased since 2018 primarily as the result of GSMP II and ES II rate adjustments for work to modernize the gas system and replace cast iron and unprotected steel mains, which provide both reliability and carbon-emissions benefits to customers. The distribution component of a Residential Gas customer bill using 1,000 therms per year has increased at a compound annual growth rate ("CAGR") of 4.3% since 2018. Despite the considerable investment to modernize the gas system, this increase is less than half of the statewide average of 10.6%. PSE&G's distribution rates are considerably less than those of the New Jersey average as PSE&G has been able to control costs and maximize the value of its prior investments.

Chart 1

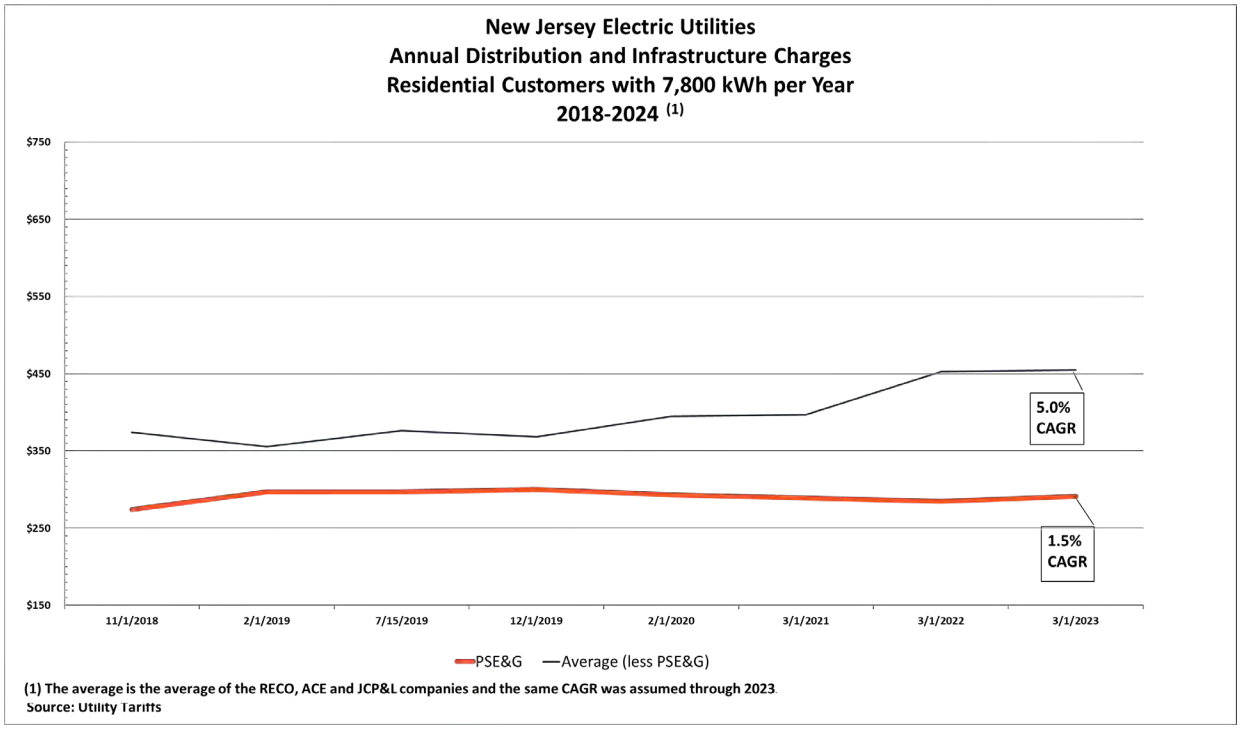


(1) The average is the average of the SJG, NJN and E-Town companies and the same CAGR was assumed through 2023.
Source: Utility Tariffs

Q. How have PSE&G's Electric distribution rates changed since the 2018 base rate case?

A. The distribution component of a Residential Electric customer bill for a customer using 7,800 kWh per year has increased at a CAGR of 1.5%, well below the statewide comparable average of 5.0%. and below inflation levels. This modest increase is driven primarily by rate increases from the ES II Program to modernize the Company's electric system and to make it more reliable and resilient. As with Gas, the Company has been able to control costs and avoid the need for an earlier base rate case.

Chart 2



Q. That shows that PSE&G electric and gas distribution charges increased at a relatively lower rate, but how do you compare on a total bill basis?

A. PSE&G's bills continue to be lower than the average of its peers.

Chart 3

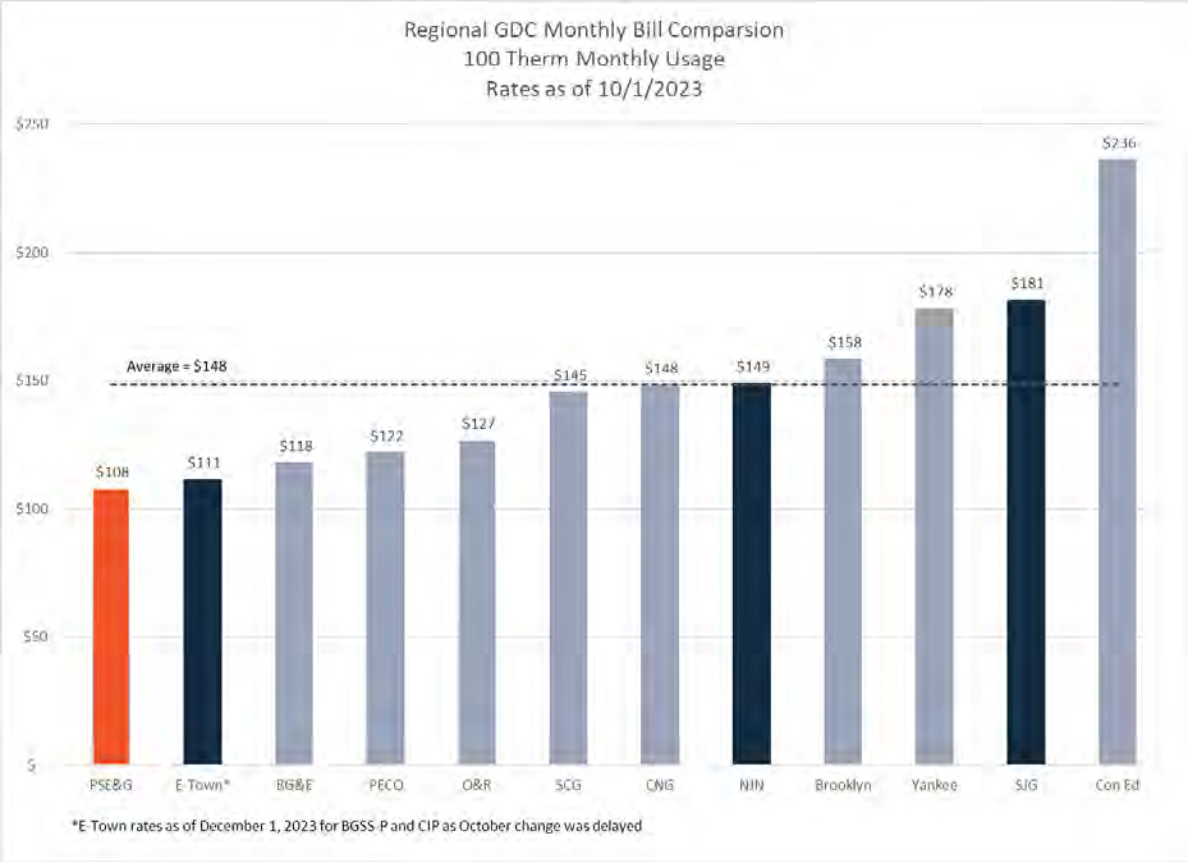
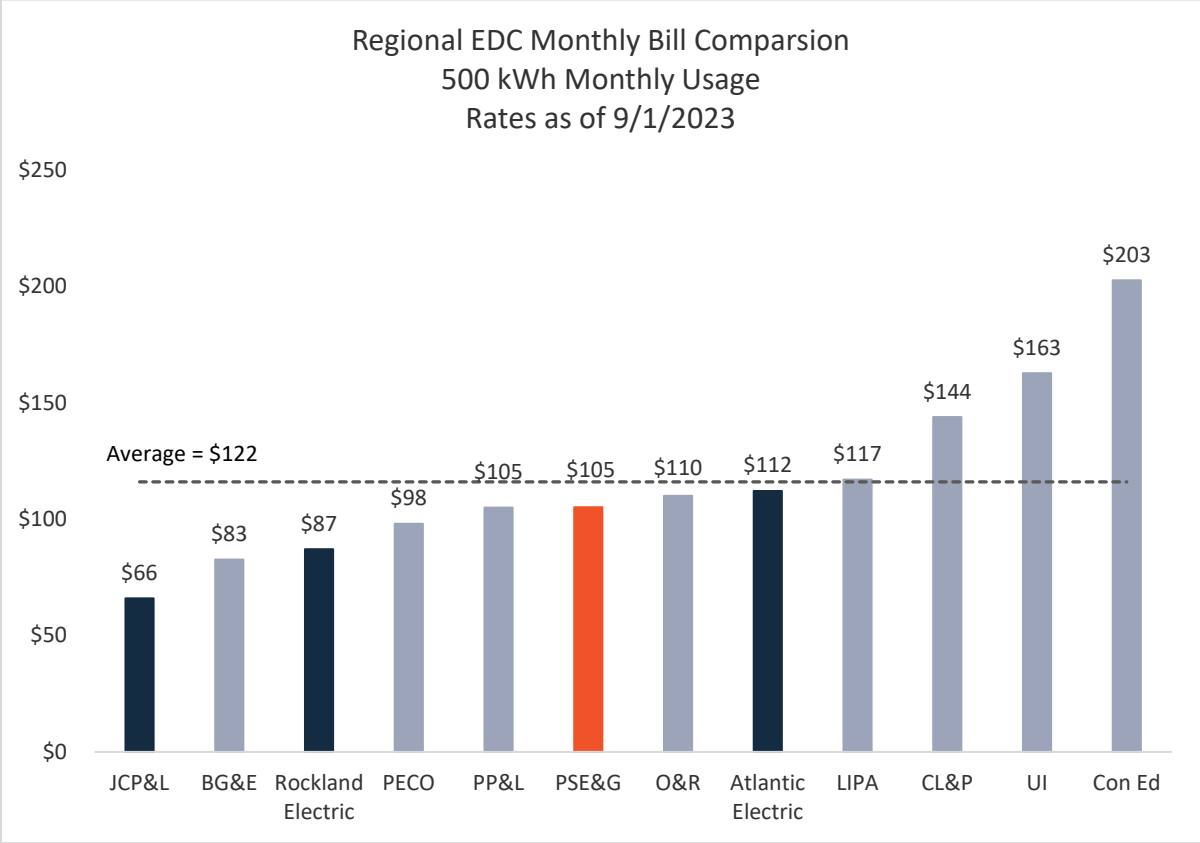

Regional GDC Monthly Bill Comparsion
100 Therm Monthly Usage
Rates as of 10/1/2023
$250
$200
$150
$100
$50
$
Average = $148
$108
$111
$118
$122
$127
$145
$148
$149
$158
$178
$181
$236
PSE&G
E-Town*
BG&E
PECO
O&R
SCG
CNG
NJN
Brooklyn
Yankee
SJG
Con Ed
*E-Town rates as of December 1, 2023 for BGSS-P and CIP as October change was delayed

Chart 4



Q. Are customers receiving value from the Company's investments and cost control efforts?

A. Absolutely. PSE&G represents a great value to its customers both in terms of cost and reliability. As shown in the tables below, PSE&G ranks the lowest for total distribution O&M per customer compared to both State, Regional and ROE proxy group peers for both Electric and Gas, and PSE&G has the best rating of cost per customer and reliability for Electric.

Chart 5

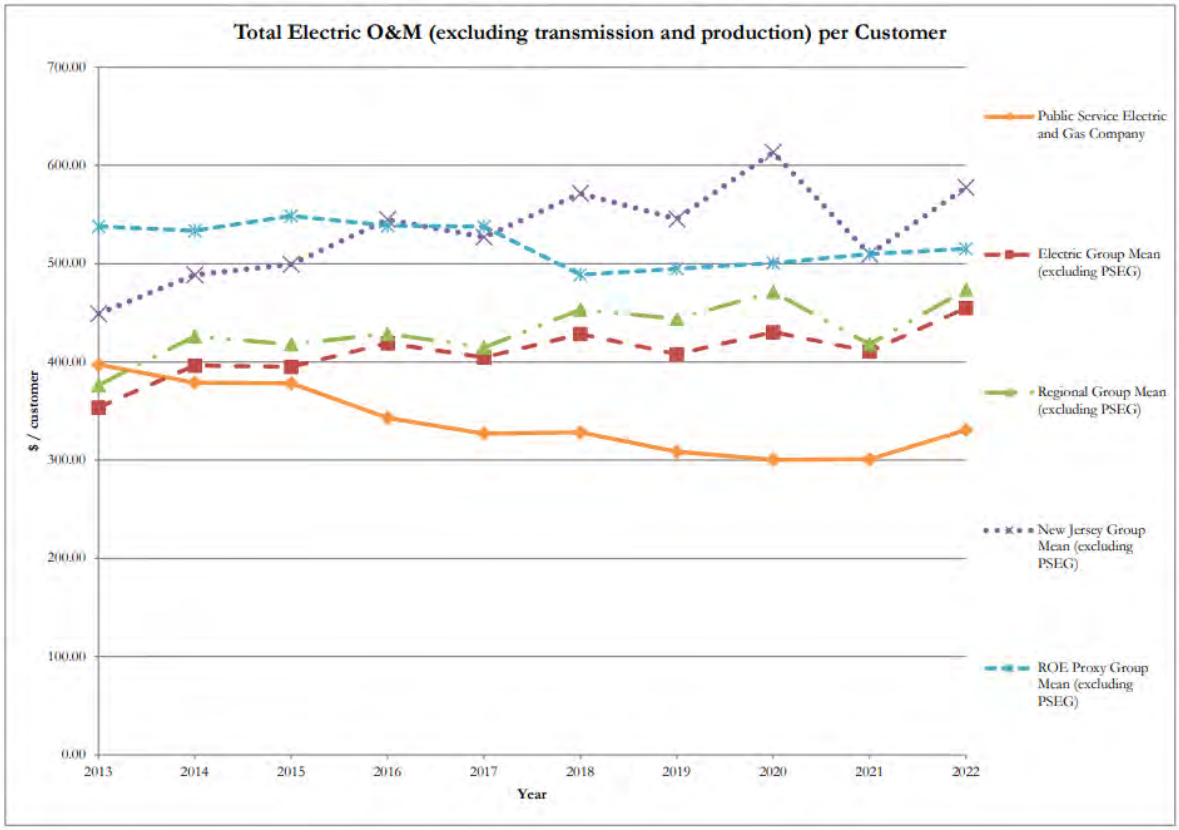

Total Electric O&M (excluding transmission and production) per Customer
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
$ / customer
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company
Electric Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

Chart 6

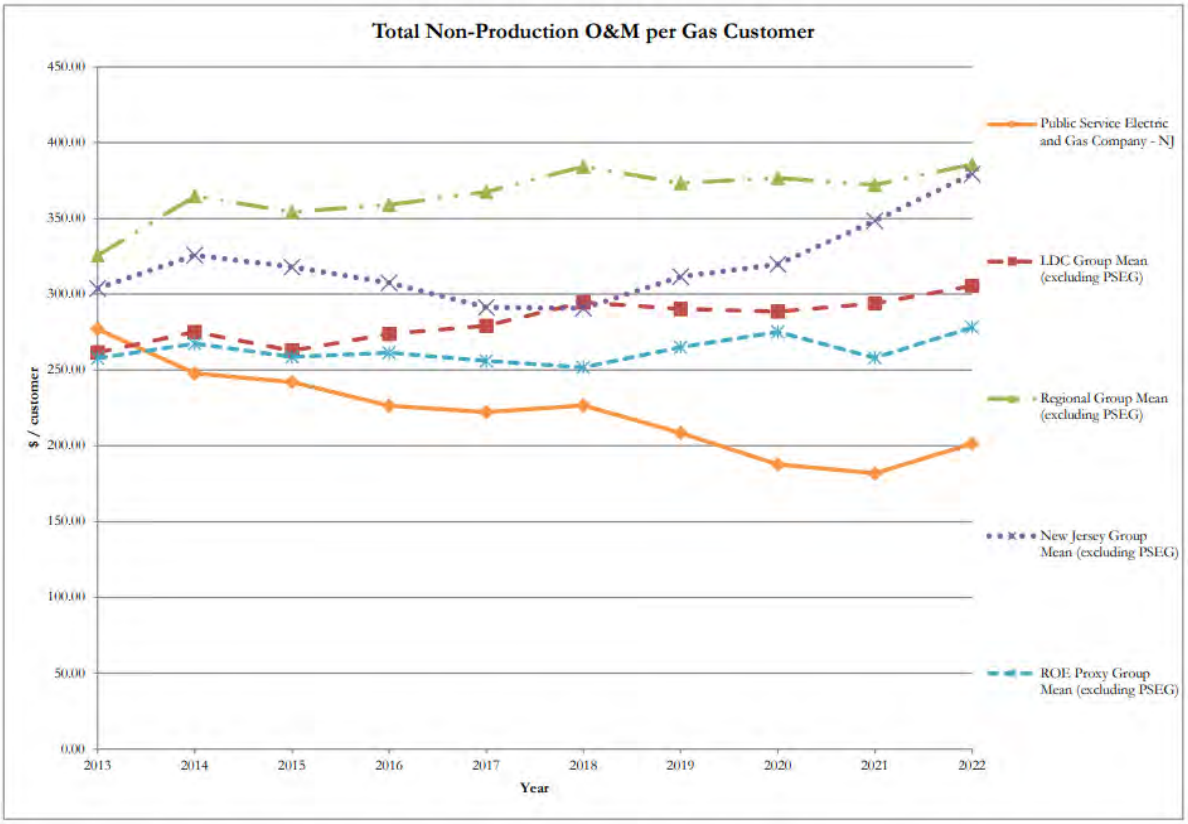
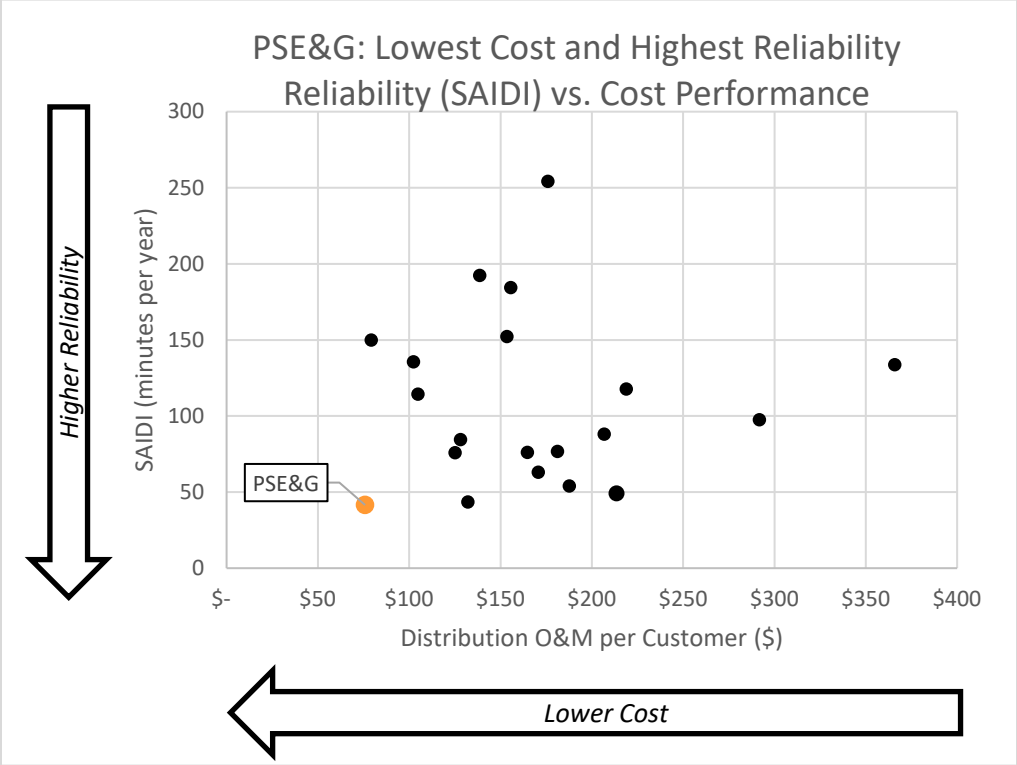

Total Non-Production O&M per Gas Customer
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
$ / customer
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
Year
Public Service Electric and Gas Company - NJ
LDC Group Mean (excluding PSEG)
Regional Group Mean (excluding PSEG)
New Jersey Group Mean (excluding PSEG)
ROE Proxy Group Mean (excluding PSEG)

Chart 7



For more details on the Company's costs and reliability compared to peers, see the testimony of Michael Adams.

Q. Have customers recognized this value?

A. Yes. The Company's J.D. Power Customer Satisfaction results for Residential and Business customers for both Electric and Gas are illustrated in the following charts. In 2022, the Company achieved better than first quartile results in all four categories.

Chart 8

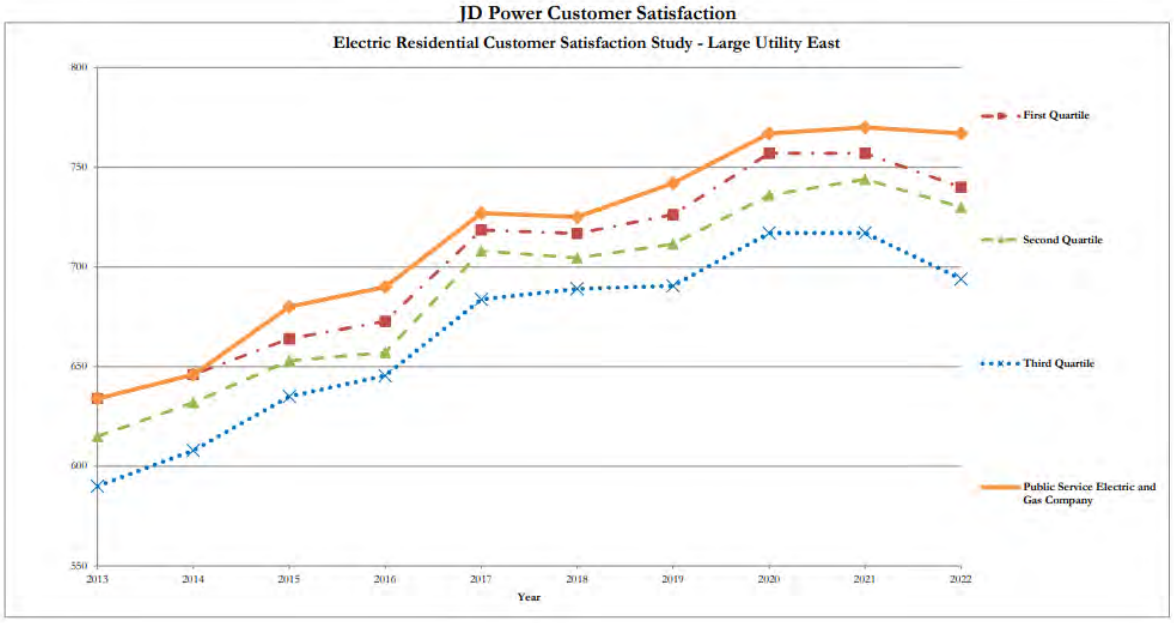


Chart 9

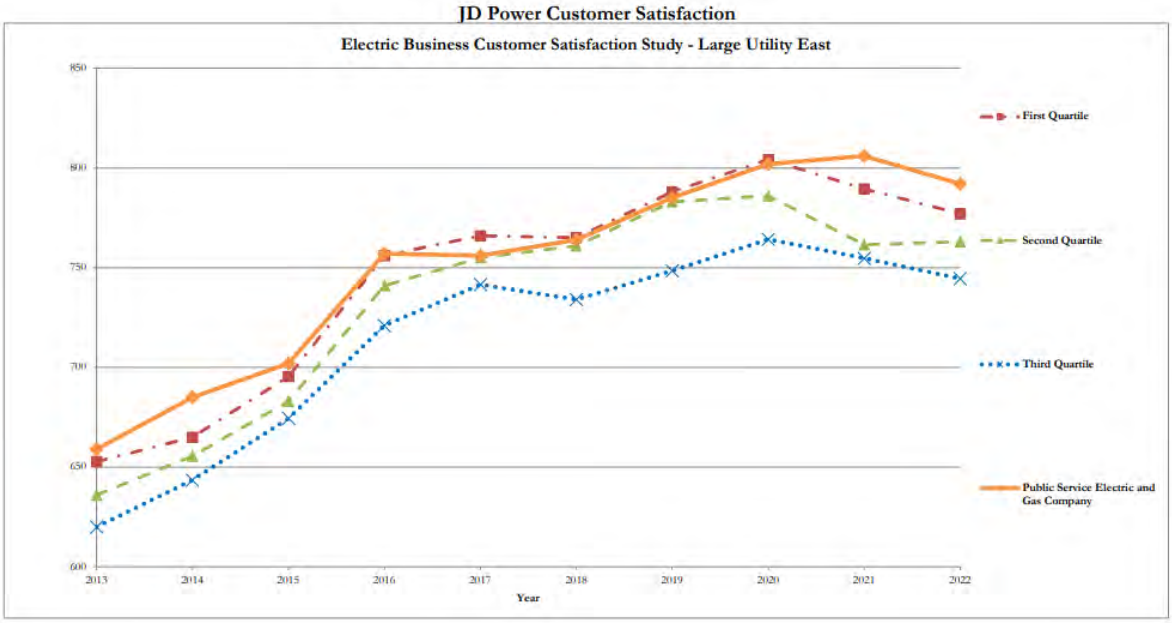


Chart 10

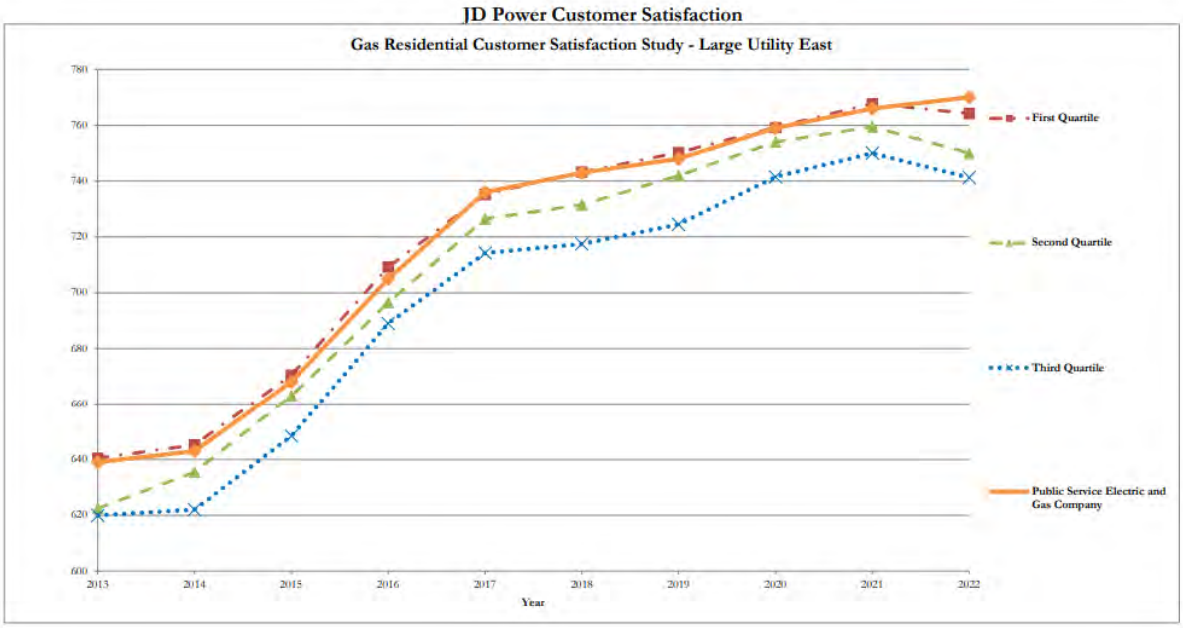
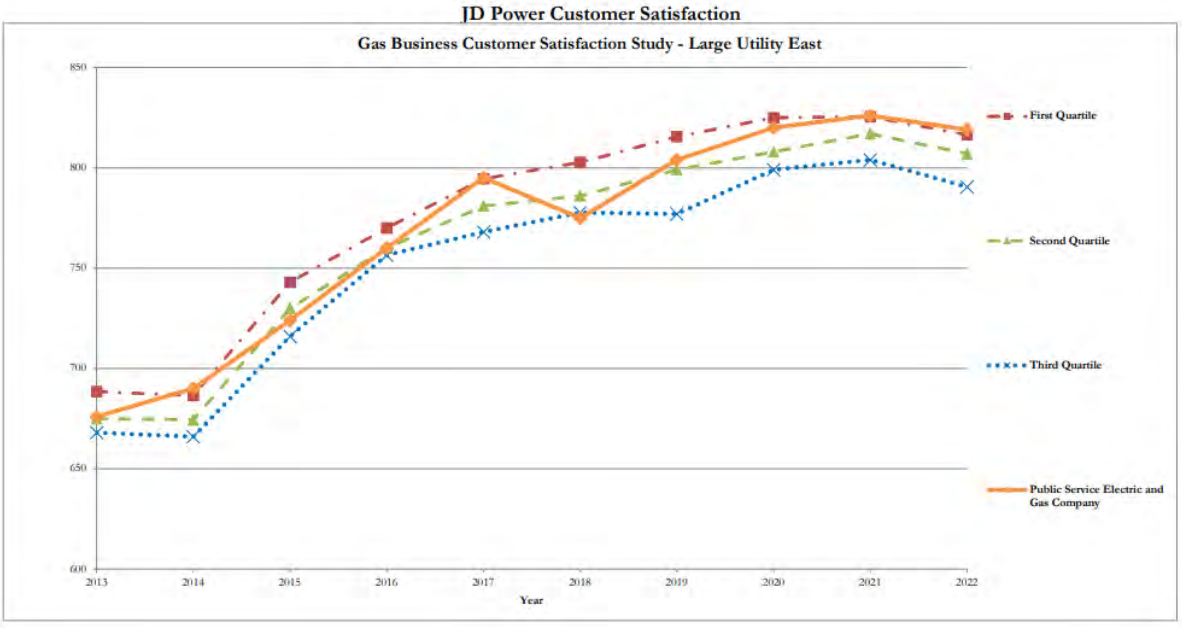


Chart 11



Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of its customer base. PSE&G's Energy Efficiency programs include special incentives targeted to lower income customers. The Company implements the State's Comfort Partners program, which provides free energy savings measures as well as upgrades to address health and safety problems in the home for lower income customers. PSE&G also introduced a new initiative in its Clean Energy Future – Energy Efficiency program targeted to lower income customers between 250% and 400% of the Federal Poverty Level, and customers in overburdened communities. This included financial incentives to both property owners and tenants in apartments and multifamily properties. The Company promotes these programs through multiple channels, including outreach events, digital and traditional media, bill inserts, social media, and marketing by trade allies.

Q. Are there other assistance programs for lower income customers outside of PSE&G's energy efficiency programs?

A. Yes. PSE&G also advocates for various grants provided to lower-income customers, including the Low Income Home Energy Assistance Program ("LIHEAP"), "Lifeline" for senior and disabled adults, the Universal Service Fund ("USF"), Payment Assistance for Electric and Gas ("PAGE"), and "NJ SHARES."

Q. Please describe what these programs are and who is eligible.

A. LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting

Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

Q. How does the Company promote these programs?

A. The Company promotes the use of these services to its customers through bill inserts, community outreach, events, and through its collection correspondence. A dedicated web site with written information and videos is also promoted and all these methods of communication occur in multiple languages where possible and appropriate. PSE&G serves the most diverse demographics in the State and, due to the nature of PSE&G's customer base, has more customers eligible for these low-income programs on a proportionate basis compared to other utilities. Consequently, this customer segment receives special focus.

Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

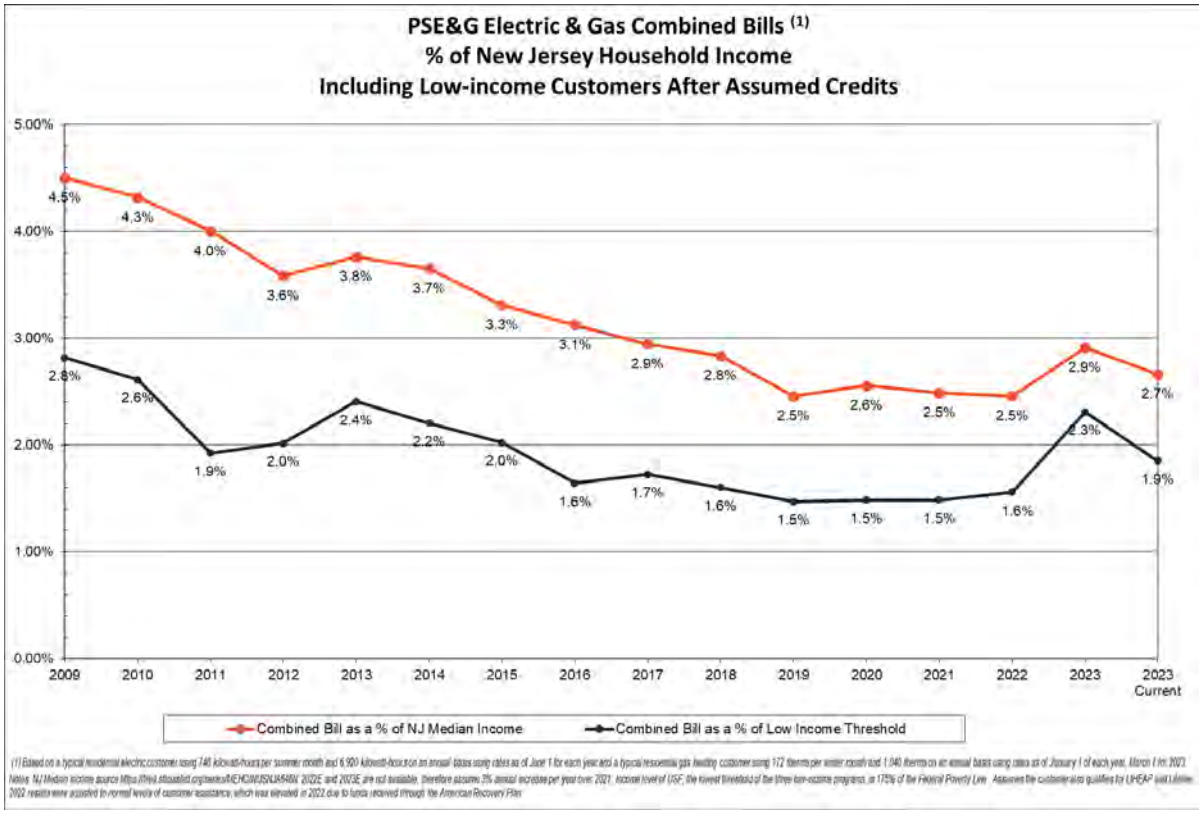
A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances for many customers. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors, as well as an external media

campaign designed to provide customers the opportunity to garner financial assistance and enter into deferred payment arrangements.

Q. Have you considered the impact of electric and gas rates on these customers?

A. Yes. As illustrated in the chart below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009.

Chart 12



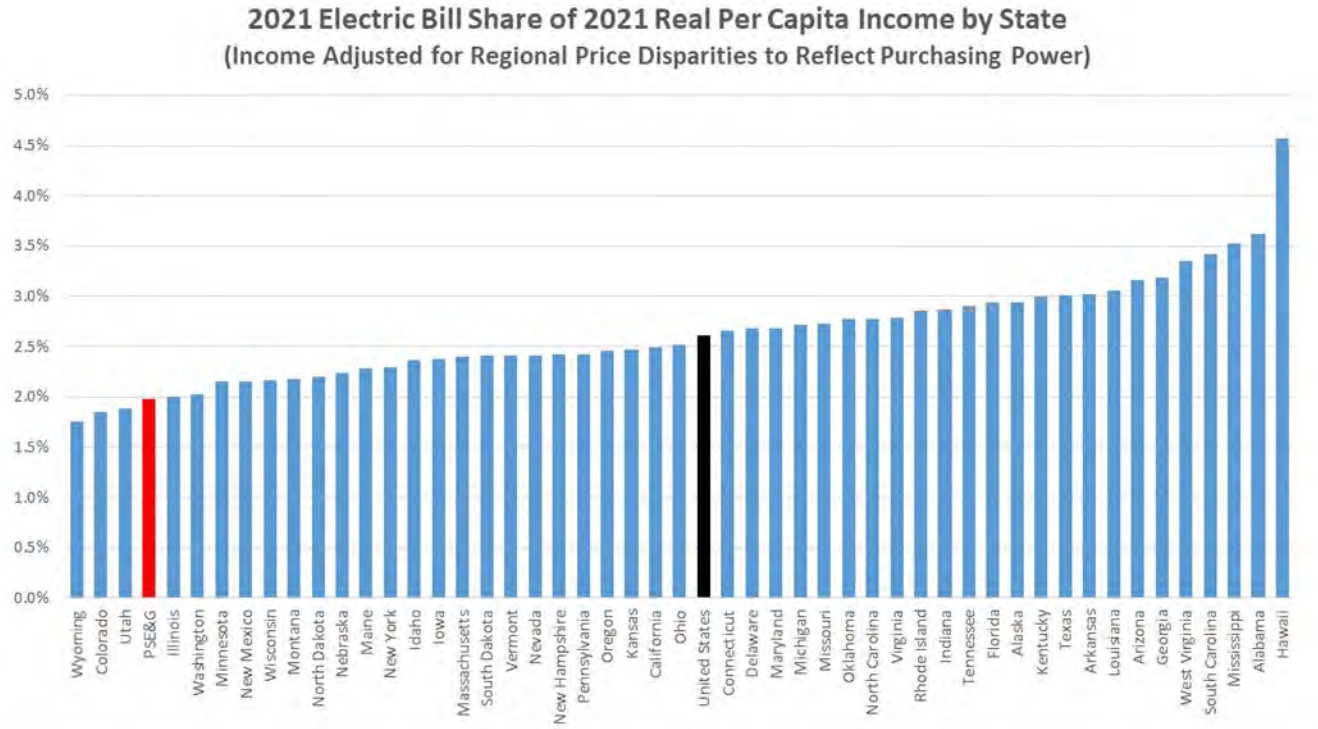
This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income

level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does this utility bill portion of overall income compare to other states?

A. Very well. As shown in the chart below, PSE&G's residential electric bill as a percentage of per capita income for NJ is in the top quartile compared to the other states in the US. In other words, PSE&G's total bill represent less share of a customer's wallet than the relative utility bill share in most of the other states.

Chart 13



Source: U.S. Dept. of Commerce, Bureau of Economic Analysis, "Regional Data GDP and Personal Income", June 2023
U.S. Dept. of Energy , Energy Information Agency, "Sales (consumption, revenue, prices & customers", retrieved July 2023.

While PSE&G's bills as a percentage of overall NJ income is very favorable compared to most other states, the Company recognizes the current economic environment and the ongoing need to control costs as much as possible. PSE&G has and will continue to control costs as much as possible to maintain affordable rates for customers without sacrificing reliability.

Q. Beyond cost control efforts, has PSE&G considered any other options for customers to lower their bills?

A. Yes. PSE&G has a robust energy efficiency program open to all customer groups to help customers reduce their usage and overall bill. Further, as discussed in the testimony of Mr. Swetz, PSE&G proposes to implement new voluntary electric time-of-use ("TOU") rate options that will allow customers to reduce their bills (as well as reduce overall system peak demand and the need for additional generation) by shifting usage when they can to off-peak periods. These new proposed TOU rates can be utilized by all residential customers to shift usage away from the system peak demand and will be particularly beneficial to electric vehicle customers that can charge their cars during off-peak hours. Further, PSE&G proposes to offer this TOU program with guaranteed bill protection for customers enrolling in the first 24 months. Customers who opt into the TOU rate options will be eligible for a refund if the total cost of the TOU rate exceeds what they would have been charged on the standard Residential ("RS") rate in the first 12 months of their enrollment. After the first year, the customers may opt-out of the program.

Q. Do you have any final comments on the impact of this filing to customers?

A. Yes. PSE&G recognizes the current economic environment and the need to keep costs to customers as low as possible. However, in addition to the requirement in the GSMP II Order

that this case be filed before January 2024, it is important to put this increase in context looking at the utility bill as a percentage of overall income both for low income customers and for customers overall. Further, PSE&G has controlled costs as much as possible, avoiding the need to file a base rate case until now and resulting in a distribution increase over the last five years well below the average for all other NJ electric and gas utilities. The increase is primarily driven by Board approved and traditional utility investments to modernize the electric and gas systems, reduce carbon emissions, and improve reliability and customer satisfaction, and by deferred costs related to major storm events. PSE&G's customers have recognized these benefits as shown in the Company's reliability results and the JD Power results, and thus PSE&G is requesting recovery of these prudent expenditures. Finally, PSE&G will continue to evaluate ways to reduce the impact to customers through additional rate options to send the right price signals to customers to help reduce bills and improve reliability.

III. FACTORS DRIVING THE NEED FOR RATE RELIEF

Q. Why is the Company seeking the requested rate increase?

A. It has been approximately five years since the Company's last base rate case filing, so PSE&G has successfully operated for an extended period of time without having to seek a base rate increase. After five years, and despite the Company's successful execution of its cost mitigation and expense control strategies, there are a number of significant factors that have driven the Company's financial results well below its authorized rate of return and that represent the primary drivers of the rate increase sought in this filing. These factors include recovery of the following:

- Board approved investment programs;
- traditional utility investments;

- insufficient depreciation and cost of removal rates;
- New Business investment with flat sales growth;
- deferred significant storm event costs; and
- working capital requirements

I will address each of these in turn.

A. Board Approved Investment Programs

Q. What are the Board approved infrastructure programs impacting this proceeding?

A. The Board has approved the Company's substantial investments in specific programs with prudency and final recovery to be determined in this proceeding. The Board approved programs that are the subject of this proceeding are:

- NJ Transit Mason Substation;
- GSMP II (as extended);
- Energy Strong II;
- CEF-EC;
- CEF-EV; and
- IAP[5]

Q. How do these programs impact this proceeding?

A. The specifics of each program and its recovery are unique and identified separately below. In general, as discussed in the panel testimony of Company witnesses Mike Schmid and Rick Fonseca, as well as in the testimony of David Johnson, PSE&G seeks a prudency

[5] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of an Infrastructure Advancement Program (IAP)*, B.P.U. Docket Nos. EO21111211 and GO21111212, Decision and Order Approving Stipulation of Settlement (June 29, 2022) ("IAP Order").

determination and final rate recovery on the NJ Transit Mason Substation, GSMP II, Energy Strong II, and CEF-EC programs. While PSE&G seeks a prudency determination and recovery of investments and expenditures associated with the CEF-EV and IAP programs that are in-service, each program will continue to have investment beyond the end of this proceeding and will require a final prudency determination on all expenditures outside this proceeding in a subsequent rate case.

Q. Please briefly summarize each program and its recovery mechanism.

A. A description of each program or area is set forth below:

a. **New Jersey Transit Mason Substation** – By Order dated November 21, 2017, making use of funds remaining from the original Energy Strong program approved in 2014, the Board approved a plan to demolish the facilities known as the Mason Substation, comprising a number of buildings and electric plant that at the time were owned by the New Jersey Transit Corporation ("NJ Transit"), and to rebuild the facilities under PSE&G ownership.[6] The substation, which is a crucial facility for both NJ Transit and for electric customers in northern New Jersey, suffered severe damage during Superstorm Sandy. The cost of the rebuilt facility is shared between NJ Transit and PSE&G. The Board authorized PSE&G to recover its prudently incurred project cost investment of up to $100 million plus an Allowance for Funds Used During Construction, in a subsequent base rate case. Station assets are placed into service as they become used and useful. To date $60 million has been placed into service and the remaining $40 million is expected to be placed in

[6] *See I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Construction of the Mason Substation Damaged During Superstorm Sandy*, BPU Docket No. EO16080788, Decision and Order Approving Stipulation (November 21, 2017), at 3-4.

service by November 2024. Therefore, as discussed in the panel testimony Mr. Schmid and Mr. Fonseca, the Company is seeking recovery of its prudently incurred substation-related costs consistent with the Mason Substation Order.

b. **GSMP II** – In the GSMP II Order, the BPU authorized the Company to invest and seek recovery through periodic rate "roll-ins" of up to $1.575 billion in capital costs over a five-year period.[7] The capital investments under GSMP II have enhanced gas system safety and achieved leak reductions. The roll-ins of GSMP II costs, which already have been approved in previous roll-in proceedings, are subject to prudency review in this base rate case.[8] The GSMP II Order also established requirements for "Stipulated Base" expenditures of approximately $300 million and other baseline capital expenditures that were not eligible for recovery through the GSMP II roll-in mechanism and thus will be recovered in this proceeding, adding to the Company's unrecovered capital balance. The Board approved the final GSMP II investment roll-ins by Order issued May 24, 2023.[9] PSE&G's revenue requirement includes all investment associated with the GSMP II Program. All revenues associated with GSMP II projects already rolled into rates are included in Operating Revenues and thus form no part of PSE&G's incremental revenue request in this proceeding. On October 11, 2023, the Board approved a two-and-a-half-year extension of GSMP II for $902 million ($752M for accelerated recovery

[7] A limited amount of O&M costs relating to the amortization of cost offsets from methane leak reductions were included in the GSMP II Rate Mechanism. GSMP II Order at p. 10.
[8] GSMP II Order at p. 8.
[9] *I/M/O the Petition of Public Service Electric and Gas Co. for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II") (December 2022 GSMP Rate Filing)*, B.P.U. Docket No. GR22120749, Decision and Order Approving Stipulation (May 24, 2023).

and $150M for Stipulated Base) starting January 1, 2024 ("GSMP II Extension").[10] GSMP II Extension will not have any rate roll-ins during the test year and thus no revenue adjustment is required. However, as described in more detail below, PSE&G will make a rate base adjustment to exclude GSMP II Extension accelerated recovery investment in the test year from the request in this case; that investment will be recovered in a future rate adjustment to ensure the investment is not double-counted. See Schedule MPM-18 for the rate base adjustment.

c. **Energy Strong II –** The Company was authorized in the Energy Strong II Order to invest up to $691.5 million ($641 million for electric and $50.5 million for gas). The rate adjustments relating to Energy Strong II costs are subject to prudency review in this base rate case.[11] The Energy Strong II Order also authorized recovery of up to $150.5 million ($100 million for electric and $50.5 million for gas) of incremental costs for specified Energy Strong II projects to the extent incurred (also known as Stipulated Base), in the Company's next base rate case. The Company is effectively and reasonably managing the Energy Strong II Program as described in the panel testimony of Mr. Schmid and Mr. Fonseca. PSE&G's proposed revenue requirement includes all investment associated with the Energy Strong II Program. Likewise, all revenues associated with the Infrastructure Improvement Program Charges for Energy Strong II projects already rolled into rates, or that will

[10] *I/M/O of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II")*, BPU Docket No. GR17070776, and *I/M/O the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP III")*, BPU Docket No. GR23030102, Decision and Order Approving Settlement (October 11, 2023) ("GSMP II Extension Order").

[11] Energy Strong II Order at 8.

be rolled into rates during the test year, are included in Operating Revenues, and thus form no part of the Company's incremental revenue request in this proceeding.

d. **CEF-EC** – By Order dated January 7, 2021, the Board approved PSE&G's CEF-EC proposal authorizing installation of 2.2 million advance metering infrastructure ("AMI") meters and related infrastructure and information technology over an approximately four-year period.[12] The Board approved deferral of actual investment up to $707 million and expenses of $71 million, or a total of $778 million for total CEF-EC expenditures. The CEF-EC Order also allowed for the recovery of prudent legacy meter stranded costs, recognizing that the acceleration of the AMI deployment will result in legacy meters being replaced before they are fully depreciated. Finally, the CEF-EC Order called for a *pro forma* revenue requirement adjustment in this proceeding to account for future savings at the completion of the AMI deployment. The CEF-EC Order allowed for deferral of program-related costs without any recovery until this base rate case. The CEF-EC program description and status are detailed in the testimony of Company Witness David Johnson. The details of the CEF-EC impact to rate base are shown on Schedule MPM-16. The proposed amortization of the CEF-EC deferrals is shown on Schedule MPM-47, and the *pro forma* revenue requirement adjustment is shown on Schedule MPM-48 and described in more detail below. Consistent with the CEF-EC Order, in this rate case PSE&G seeks recovery of prudently incurred actual AMI expenditures as well as stranded costs related to legacy meters.

[12] *See* CEF-EC Order.

e. **CEF-EV** – By Order dated January 27, 2021, the Board approved PSE&G's CEF-EV program, in which the Company was authorized to invest up to $166.2 million to implement its CEF-EV program and to incur up to $38 million of incremental O&M expenses associated with the program.[13] The CEF-EV program description and status are detailed in the testimony of Company Witness Karen Reif. Consistent with the CEF-EV Order, in this rate case PSE&G seeks recovery of prudently incurred actual investments and CEF-EV related O&M expenses. The details of the CEF-EV impact to rate base are shown on Schedule MPM-17. The details of the proposed amortization of the CEF-EV deferrals are shown on Schedule MPM-49 and described in more detail below. In addition, while not a factor impacting the rate request in this proceeding, the CEF-EV Order allowed for annual roll-in filings for investment not expected to be in-service by six months after the end of the test year in this base rate case. The testimony of Company witness Mr. Swetz details the template for those future roll-in filings.

f. **IAP** – The Company was authorized in the IAP Order to invest up to $351.0 million ($281.2 million for electric and $69.8 million for gas) to be recovered through an accelerated rate adjustment mechanism, designated the IAP Rate Mechanism.[14] The IAP program description and status are detailed in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca. The Board also required stipulated base expenditures of $160.0 million on incremental costs outside the IAP Rate Mechanism to be recovered in the Company's next base rate case if found to be reasonable and prudent. While this program is not complete and final prudency on

[13] *See* CEF-EV Order.
[14] *See* IAP Order.

all expenditures outside of this proceeding will not occur until a future base rate case proceeding, PSE&G estimates $53 million of stipulated base expenditures in service through the end of the test year on May 31, 2024 and a total of $73 million in service up to 6 months beyond the end of the test year; PSE&G seeks to recover those costs in this proceeding. In addition, as described in more detail below, PSE&G will make a rate base adjustment to exclude IAP investment in the test year from the request in this case; that investment will be recovered in a future rate roll-in to ensure the investment is not double-counted. See Schedule MPM-15 for the rate base adjustment.

Q. Why was the authorized interim recovery of costs associated with these programs insufficient?

A. The Company was approved for interim rate adjustments for only a portion of its Energy Strong II, GSMP II and IAP investments. PSE&G seeks recovery of the investment in these programs that is not subject to interim recovery, referred to as Stipulated Base. The Company was authorized by the Board to make these investments with recovery to commence in a base rate case proceeding. For the NJ Transit Mason Substation, CEF-EC, and CEF-EV programs, there was no interim recovery approved before this proceeding and recovery for all in-service expenditures will commence from this rate case proceeding.

Q. Are there any adjustments to the GSMP II, Energy Strong II, or IAP interim rate adjustments to ensure recovery of investments is not double-counted?

A. Yes. As described in more detail below, a *pro forma* adjustment is being proposed to annualize any interim rate adjustments during the test year to ensure the Company does not double count the revenues associated with any of these programs. These adjustments will increase the Company's Operating revenue as if the interim rates were in effect for the entire

test year, which reduces PSE&G's request. There were no rate adjustments during the test year for the gas business as all rate adjustment occurred by the June 1, 2023 start of the test year. There are ES II and IAP rate adjustments during the test year for electric. Please see Schedule MPM-44 for the adjustment.

B. Traditional Utility Investments

Q. Have the Company's non-program-related investments impacted PSE&G's request in this proceeding?

A. Yes. From the conclusion of PSE&G's prior base rate case through the start of the current test year on June 1, 2023, the Company has invested $5.8 billion ($2.4 billion for electric and $3.4 billion for gas) in service to support safe, proper, and reliable service. To put that amount into context, the Company's approved total rate base balance in the 2018 base rate case was $9.5 billion ($5.5 billion for electric and $4.0 billion for gas). While some of that investment is associated with Board approved programs detailed above, the majority is associated with traditional utility base investments. These investments include accelerating the replacement of the aging cast iron and unprotected steel piping in the Company's system and modernizing the gas system to reduce methane emissions and improve safety and reliability, as well as improving the performance of the electric system by retiring certain older substations and investing in circuits prone to outages. Details concerning PSE&G's base capital investments are discussed by panel witnesses Mr. Schmid and Mr. Fonseca. This capital investment far exceeds the amount the Company is recovering in depreciation expense in current rates, increasing PSE&G's rate base and the depreciation expense needed to recover

this investment. PSE&G is seeking recovery of and on all prudent investment in the system in this proceeding.

C. Insufficient Depreciation and Cost of Removal Rates

Q. Please explain the impact of depreciation on PSE&G's need for rate relief.

A. It is widely acknowledged that aging infrastructure is one of our nation's greatest challenges. Since depreciation rates are the mechanism through which a utility recovers the dollars expended for its capital projects, establishing the appropriate depreciation rates for a utility is critical to establishing just and reasonable rates. Properly set depreciation rates allow the Company to recover its investments timely, charge those costs to the customers who benefited from their use, and fund new capital construction. Company witness Mr. John Spanos has conducted a detailed evaluation of PSE&G's assets and developed new depreciation rates based on that evaluation to recover the costs of replacing aging infrastructure over its useful life and account for the cost to remove assets in the future. As described in Mr. Spanos' testimony, the Company's current depreciation rates are insufficient, largely due to the fact that the rates are not permitting the Company to recover its cost to remove and retire plant for which there is no more useful life (i.e., cost of removal). Prior reductions in the accrual for cost of removal have resulted in under-collection of those costs. The Company is proposing new depreciation rates that properly account for cost of removal and will allow the Company to appropriately recover its expected costs as it replaces aging infrastructure See Schedule MPM-41 for the impact of the proposed depreciation rates.

D. Flat Sales Despite Customer Growth

Q. How have PSE&G's sales changed since the last rate case?

A. On a weather-normalized basis, electric sales have slightly declined while gas sales have slightly increased. However, customers have steadily increased, so on a per customer basis, weather-normalized sales for both electric and gas have declined.

Q. Has this decline in sales meaningfully impacted the Company's margin (revenues less expenses)?

A. No. The Company's margin has been maintained due to the Conservation Incentive Program ("CIP").

Q. Please describe the CIP.

A. The CIP mechanism was approved by the Board in the Clean Energy Future – Energy Efficiency matter on September 23, 2020 in Dockets Nos. GO18101112 and EO18101113 ("CEF-EE Order").[15] The CIP rate mechanism provides a rate adjustment related to changes in the average revenue per customer when compared to a baseline revenue per customer, removing the disincentive for the Company to encourage customers to conserve energy. Because of the CIP, flat to declining sales growth is not a factor requiring PSE&G to request rate relief.

Q. What is the impact of a base rate case filing on the CIP?

A. Anytime a base rate case is filed, the CIP baselines will reset. As described in more detail below, PSE&G will reset the CIP baselines in this proceeding to the approved billing

[15] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis*, Order Adopting Stipulation, BPU Docket Nos. GO18101112 and EO18101113 (September 23, 2020).

determinants for this test year of June 2023 through May 2024. This will shift the recovery of the revenue from the CIP accrual to base rates, increasing rates in this proceeding (but significantly lowering the CIP accrual for future years). Generally, this is just a transition of recovery from the CIP to base rates. However, the CIP is recovered or refunded to customers on a one-year lagged basis, so when base rates increase, the CIP accrual will subsequently decline, but the CIP rate in effect will remain, resulting in a net increase in rates to customers. The details of the *pro forma* adjustment to remove the CIP accrual currently included in operating revenues for recovery in base rates is shown in Schedule MPM-50.

E. Major Storm Event Recovery

Q. Please describe the regulatory asset PSE&G seeks to recover in connection with Major Storm Events.

A. The Company seeks to recover $109 million of deferred major storm costs incurred by the Company since the last rate case. As described in detail in the testimony of panel witnesses Mr. Schmid and Mr. Fonseca, that $109 million is the result of five Major Storm Events on the following dates:

- August 4-13, 2020 (Tropical Storm Isaias/State of Emergency) $72M;
- June 3, 2020 (Derecho/thunderstorms) $15M;
- July 17-18, 2019 (Major Storm) $12M;
- September 1-28, 2021 (Hurricane Ida/State of Emergency) $8M; and
- Jan. 31- Feb. 23, 2021 (February 2021 Snow Storms/State of Emergency) $2M;

Q. Is the Company recovering any of these costs through base rates?

A. No, it is not. In the 2018 base rate case, the Company deferred all major storm event costs prior to and during the test year. Those costs, along with other regulatory assets were

resolved through a black box settlement, with amortization of the agreed upon total regulatory assets over a five-year period. Because the test year Major Storm Events were deferred, there were no Major Storm Event costs reflected in the test year expenses and thus nothing in base rates to recover any post-test year Major Storm Events.

Q. Can you summarize your request for Major Storm Event costs?

A. The Company is seeking recovery of all prudently incurred Major Storm Event costs that have been deferred since the last rate case. These costs were incurred in preparation for and response to Major Storm Events that are outside the Company's control. As described in more detail below in Section IX, the Company is seeking a Storm Recovery Charge to recover these costs going forward.

F. Working Capital

Q. What is Working Capital?

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments. The amounts included in the test year are described in more detail below.

Q. How has Working Capital changed since the last rate case?

A. The primary driver of the large increase in working capital is related to the Company's cash working capital needs. As described in the testimony of Company witness Mr. Adams, the cash working capital requirement is comprised of a lead-lag study and net asset liability analysis.

Since the last rate case, the cash working capital requirements from the lead-lag study have increased due to a significant increase in the collection lag from customers. Since 2020 the Company's Accounts Receivable balance has increased significantly. While the Company is working with customers to address their arrears, there remains a significant lag in revenue recoveries, increasing working capital needs. This working capital requirement is not for recovery of uncollected bad debt, but recognition of an ongoing lag in revenue recovery. Further, since the last rate case, the Company has successfully managed its pension and OPEB plans, which results in net pension and OPEB income and an offsetting entry to record a pension asset. Each of those are reflected in this rate case (crediting the 2024 pension and OPEB income to customers and recovering the corresponding pension asset which is part of working capital).

Q. Why have Materials and Supplies increased?

A. The increase in inventory is primarily a result of ensuring material availability for planned increases for system maintenance and capital work. Due to extended lead times and supply chain constraints, PSE&G has restructured its approach to purchasing inventory material. The Company has diversified the supplier base in many material categories in an effort to increase material availability and reduce lead times. The Company also implemented more enhanced material forecasting models that have translated into increased inventory levels to support operations. Raw material and labor shortages stemming from the pandemic combined with increased demand industry-wide has also resulted in price increases impacting inventory values. Conductors and transformers are especially vulnerable to fluctuations in the metals markets, and commodities like aluminum and copper have been very volatile the last few years. PSE&G's strategy to diversify suppliers also includes use of international vendors, which adds cost to accommodate overseas shipping and logistics.

IV. MITIGATION OF THE RATE INCREASES

Q. Has PSE&G taken steps to minimize the rate change requested?

A. Yes. I will describe in this section some of the successful cost-containment efforts made to enable the Company to limit its total O&M expense since its last test year in 2018. The Company takes very seriously its responsibility to customers to manage its costs prudently and to be good stewards of the electric and gas distribution systems and the customer funds needed to operate and maintain them effectively. It is important to note, however, that while maintaining a much lower cost structure, PSE&G has preserved operational performance – safety, reliability, and customer satisfaction – that is, generally, top quartile in the industry, as noted above and more comprehensively in the testimony of Michael Adams.

Q. Please discuss the steps that the Company has taken to limit the rate increase.

A. The Company has taken a number of steps to mitigate the magnitude of the rate increases proposed in this proceeding. First, the Company proposes to flow-back to customers significant tax benefits to replace expiration of the unprotected Excess Deferred Income Taxes ("EDIT") refunded to customers through the TAC as a result of the 2018 base rate case. Second, the Company has contained the growth of distribution-related O&M expenses, including electric and gas distribution operating costs, while reducing certain administrative and general ("A&G") costs, including pension and benefits costs. Third, PSE&G has managed its interest costs as prudently as possible and is anticipating approximately the same long-term debt rate as in the 2018 rate case by the end of the test year despite the significant rise in interest rates. Finally, the Company's Appliance Service Business has grown its net margins (revenues less expenses), which reduces the revenue request in this proceeding. All of these factors have enabled the Company to reduce the rate request that it otherwise would have made.

A. Tax Adjustment Credit ("TAC")

Q. Please describe the current TAC.

A. As discussed in the testimonies of Company witnesses Mr. Pardo and Mr. Swetz, the TAC is a mechanism approved in the 2018 base rate case to flow-back certain tax benefits to customers. The TAC allowed for the flow back to customers of the Federal Tax benefit associated with EDIT and the Historic Safe Harbor Adjusted Repair Expense ("SHARE") as outlined in the 2018 rate case order below:[16]

Table 2

Tax Flow-Through Balances				
$000				
	Electric	Gas	Total	Amortization
Excess deferred tax (EDIT) flowback - Protected	424,259	326,618	750,877	ARAM
EDIT flowback - Unprotected (Rate Base Related)	175,105	213,929	389,034	5 yr
EDIT flowback - Unprotected (Non-Rate Base Related)	56,308	59,971	116,279	5 yr
Histroic SHARE flowback	130,493	287,201	417,694	10 yr
Total	**786,165**	**887,719**	**1,673,884**	

The TAC also required the flow-back of January – March 2018 income tax recovery, the flow-through of the Current SHARE, a return on the increase in rate base as a result of the flow back at the Company's Weighted Average Cost of Capital ("WACC"), and the payment of interest at WACC on the non-rate base related EDIT.

[16] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order") at Stipulation ¶ 15.

Q. What is meant by "protected" and "unprotected" EDIT?

A. As discussed in the testimony of Mr. Pardo, EDIT can be classified in two categories: (1) those restricted by the normalization provisions of the Tax Cuts and Jobs Act (sometimes referred to as "protected" EDIT); and (2) those that are not (sometimes referred to as "unprotected" EDIT).

Q. What is the status of the Flow-Through Balances approved in the 2018 rate case outlined in the table above?

A. The protected EDIT is amortized to customers using the IRS-mandated Average Rate Assumption Method ("ARAM") and will continue to be refunded to customers through the TAC. As discussed in the testimony of Mr. Pardo, the historic SHARE was designed so one third of the accumulated balance would be refunded over the first approximately five years ending December 31, 2023 and the remaining two thirds would be refunded over the remaining five-year period ending December 31, 2028. The unprotected EDIT balance will primarily be refunded by the end of 2023 and fully refunded by the end of 2024. The unprotected EDIT represents the largest annual amortization, and its completion has resulted in a significant reduction in the amount to be refunded to customers through the TAC.

Q. Is the Company proposing any adjustment to the TAC in this proceeding?

A. As discussed in the testimony of Mr. Pardo, there are tax deductions for what is referred to as Mixed Service costs that are not subject to IRS normalization rules and can be flowed-back to customers. The Company is proposing to flow back both the historic deferred tax balance associated with the Mixed Service deduction as well as the future deductions it will claim. This is consistent with the existing Historic SHARE flow-back to customers through the TAC (although PSE&G is proposing a more accelerated refund of Mixed Service costs to

customers than the 10-year period for the SHARE). This represents a significant benefit to customers and lowers the Company's revenue request.

Q. Are there any other changes to the TAC?

A. Yes. As discussed in the testimony of Mr. Pardo, the Company is proposing to refund a pre-set amount for the current period SHARE and Mixed Service deductions, with any difference between the actual and pre-set amount deferred for refund to customers in a future proceeding. This has the benefit of providing consistency in the flow-back to customers to avoid rate swings from changes in the current deduction and will potentially provide an additional balance to flow-back to customers at the end of the amortization of the historic Mixed Service deduction to mitigate future increases to customers when the amortization is complete. To this point, as discussed in the testimony of Mr. Swetz, the Company also proposes to shape the amortization of the historic Mixed Service flowback to decline over an approximately five-year period to avoid a significant impact to customers after the final year of the amortization. Further, as also discussed by Mr. Swetz, the Company is proposing an adjustment to the Gas allocation of the TAC among customer classes so that all of the refund is attributed to firm customers. For more details on the TAC components, please see the testimony of Mr. Pardo. For details on the calculation of the TAC, proposed rates, and bill impacts, see the testimony of Mr. Swetz.

B. Cost Containment Measures – O&M

Q. Does PSE&G describe in this filing the actions that the Company has taken to control electric and gas operating distribution-related O&M expenses?

A. Yes, Mr. Schmid and Mr. Fonseca describe these actions in detail in their panel testimony. In general, the Company seeks to measure and optimize distribution-related O&M

expenses by regularly benchmarking costs and setting targets to improve results year after year. This fosters an environment of continuous improvement and results in a continuous focus on cost control and operational improvement.

These cost control efforts have helped to offset increases in distribution-related O&M costs due to inflation, including cost increases to satisfy regulatory requirements, and other cost increases since the Company's last rate case. Mr. Schmid and Mr. Fonseca's panel testimony on PSE&G's electric and gas operations provides examples of how PSE&G seeks to manage these costs while obtaining strong operating results. One example of cost containment is PSE&G's treatment of wages.

Q. Has the Company taken measures to control wages?

A. Yes. In the area of wages and benefits, the Company has controlled distribution-related O&M growth by regularly assessing its compensation levels to keep them competitive with the market while providing appropriate incentives to employees to focus on key operational metrics and critical business initiatives. The objective has been to ensure employee compensation programs remain market competitive and continue to enable the Company to attract, retain, and develop a talented and diverse workforce. Prior to 2023, PSE&G has generally provided average annual merit/wage increases between 2.5% to 3% to employees. In 2023, annual merit/wage increases averaged 3.5% to 4% in line with current market competitive conditions. The Company is currently evaluating its compensation programs, including but not limited to merit/wage increases, to ensure it remains market competitive. PSE&G also manages union employee costs through a rigorous collective bargaining process. In March 2023, the Company reached a new four-year bargaining agreement with all of its

unions that set merit increases between 3% and 4% for the agreements' terms, below recent inflationary levels.

Q. Has the Company taken any other steps to control wages?

A. Yes. In 2022, the Company initiated a Voluntary Exit Incentive Program ("VEIP") for non-represented employees that will result in the voluntary retirement of approximately 240 employees (of which 185 are from the utility and service company) by December 31, 2023, the majority of whom are Final Average Pay (FAP) pension participants. The VEIP offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks, in line with current separation plan provisions. While a portion of these severance benefits will be paid in the test year, PSE&G proposes a *pro forma* adjustment to remove these non-recurring expenses so they are never collected from customers. The Company anticipates savings by 1) not filling all vacated positions, and 2) reducing pension liability, since any external replacements of positions that are vacated will participate in the Cash Balance Pension plan.

C. Cost Containment Measures – A&G (Pension and Benefits)

Q. How has PSE&G's control of pension costs mitigated the impact of the rate increase sought in this filing?

A. PSE&G has a long history of successfully controlling pension costs, and the considerable control the Company has exercised over this expense has translated into an estimated proposed revenue requirement for Pension and Other Post-Employment Benefits ("P&OPEB") *income* of approximately $9 million for calendar year 2024.[17] It should also be noted that the proposed revenue requirement would be relative to PSE&G's pension and OPEB

[17] This estimate will be known and measurable before the end of the test year.

liability of $4.2 billion based on year-end 2022. Even if the estimated income were to decline or even switch to an expense due to market conditions once the 2024 amount is known, it would still be extremely modest compared to the liability.

Q. Please describe the steps that the Company has taken to control P&OPEB costs.

A. PSE&G was among the first utilities in the country to close a Final Average Pay Pension Plan ("FAP") to new entrants and move to a Cash Balance Pension Plan construct for all new hires starting in the mid-1990s. Further, in 2011, the Company froze the FAP benefit structure for existing non-represented employees, which was calculated utilizing the five highest years of compensation through 2011 and created a new FAP benefit structure for existing non-represented employees, which was calculated utilizing the seven highest years of compensation, reducing pension expense and future liability. Since its last base rate case, PSE&G has adopted several cost measures that helped to further lower P&OPEB costs and reduce ongoing volatility. To highlight several:

- Diversifying the investment portfolio to include real assets, such as real estate and infrastructure, to reduce volatility;
- Adjusting the pension plan asset allocation strategy to reduce the funded status sensitivity to interest rate movements;
- Splitting the plan into "active" and "inactive" which allowed for a lengthening of the aggregate amortization period, reducing expense and volatility;
- As noted above, offering a voluntary early retirement plan, eliminating future compensation costs, and reducing associated volatility;
- Negotiating the allowance of a Defined Contribution-only pension offering for the Company's unions that will reduce future pension costs and volatility;

- Reducing medical expenses by transitioning Medicare-eligible retirees to a private exchange for procurement of health insurance and providing an annual credit to retirees by way of deposits into a notional Healthcare Reimbursement Account (HRA); and
- With approval from the BPU, implementing a five-year smoothing of the actuarial gains/(losses) associated with pension asset performance, which reduced 2023 pension expense by $55 million and also reduces the volatility of future pension expense levels.

Based on the investment returns that the Company has achieved in the past, the expected actuarial returns on pension funds in the test year, and the changes noted above that have assisted in improving the funding levels of the plans, PSE&G's pensions and OPEB are currently projected to result in projected income (negative expense) for the test year and calendar year 2024.

Q. Has the management of the returns on the pension funds also lowered expenses?

A. Yes. The management of the Company's pension funds has been exemplary over the long term. For the most recently available 10-year period ending June 30, 2023, PSE&G is in the top quartile ranking in the Trust Universe Comparison Service ("TUCS") rankings for trust returns. TUCS is a report published by Wilshire, an independent investment consulting firm, designed for trusts to evaluate their performance; the ranking reflects all decisions including asset allocation, policy guidelines, and manager selection. The Company's asset allocation decisions and investment manager selections have resulted in annualized long-term returns that exceed the industry median by more than 1% over the ten years through June 30, 2023. This superior management has resulted in higher actual returns and fund balances. As a result, this leads to lower costs in the test year.

Q. As a result of these measures, what is the P&OPEB expense in the test year and are you proposing any *pro forma* adjustments related to P&OPEB expense?

A. As a result of these actions, as well as present market conditions and other factors, the Company projects approximately $54 million of income from P&OPEB in the test year. This is a reduction to the revenue requirement request. However, the test year does not reflect the most recent go forward pension and OPEB revenue requirement. The P&OPEB expense is determined in January for the calendar year. As a result, the 2024 full calendar year expense will be known and measurable before the end of the test year. The Company proposes a *pro forma* adjustment to use the known annual P&OPEB expense at the end of the test year, which will be the 2024 actual P&OPEB expense. A forecast is included in this initial filing, but the final 2024 P&OPEB income will be determined in 2024 and should be used in place of the test year amount to reflect the latest known and measurable amount. If 2024 actual results are P&OPEB income as projected, this would be a reduction to the revenue requirement request. However, the Company cannot offset such a reduction in revenue requirements and make itself whole by taking that cash out of the P&OPEB funds. Additionally, any reductions in revenue requirement reduces operating cash flow and adversely impacts PSE&G's credit metrics. P&OPEB income is an actuarial result of the actions PSE&G took to reduce costs, as described above. Since the projected P&OPEB income is non-cash, the net offset is to record an asset. Each of these items impacts the request in this rate case, with P&OPEB income reducing revenue requirements and the pension asset included in working capital. The Company does not have access to the pension income that would reduce its revenue request in this proceeding and thus should be allowed a working capital adjustment to account for the net pension asset that is driving the pension income.

If a working capital adjustment is not reflected for the P&OPEB asset (net of the impact of smoothing as agreed to in the Pension Accounting Order[18]), any P&OPEB income reflected in the revenue requirement should be $0 as the Company does not have access to the cash associated with the income. Either of these two treatments ensure symmetry between the paper P&OPEB income under the plan and the corresponding P&OPEB asset – with either both included in calculating revenue requirements, or both excluded.

Q. Are you making any other proposal with regard to P&OPEB expense?

A. Yes. As described in more detail later in my testimony, the Company proposes that any difference between the utility P&OPEB income amount credited to customers in this proceeding and actual results be deferred for recovery or refund in a subsequent base rate case proceeding. P&OPEB costs have significant annual volatility driven by factors outside the Company's control, such as market gains and losses and changes in interest rates. The Company has done a very effective job managing P&OPEB costs as noted above. The Pension Accounting Order does help reduce volatility, but significant volatility in annual pension costs remains. Deferring any amount above or below the amount reflected in the revenue requirement in this rate case will allow flexibility in the amount incorporated in rates. A reconciliation mechanism also protects customers and the Company from significant swings in the pension income, so neither is a winner or loser based on short-term market fluctuations.

[18] *I/M/O Public Service Electric and Gas Company's Request for an Accounting Order Authorizing the Company to Modify Its Pension Accounting for Ratemaking Purposes*, BPU Docket No. ER22090549, Decision and Order Approving Stipulation (February 17, 2023) ("Pension Accounting Order").

D. Cost Containment Measures – Interest Expense

Q. Please describe the steps taken to control the Company's interest costs.

A. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.02%, comparable to the embedded cost of long-term debt as of June 30, 2018 of 3.96%, which was the amount used to establish the cost of capital in the Company's 2018 Distribution Base Rate Case. Despite headwinds due to the inflationary environment, the Company has been able to maintain the embedded cost of debt at virtually the same reduced level set in the 2018 rate case. This result is primarily due to issuing long-dated debt during the historically low interest rate environment experienced over the past decade, strong PSE&G credit ratings, and solid execution of PSE&G's financing plan.

At present and for the foreseeable future, all companies will be faced with a higher interest rate environment. For example, in August 2023, PSE&G issued long-term debt at coupons for a 10-year bond of 5.20% and a 30-year bond at 5.45%, which is well above the Company's current embedded cost of debt. Given the prevailing current interest rate environment, this filing includes the estimated May 31, 2024 embedded cost of 4.02% rather than the October 31, 2023 actual cost of 3.87%. However, the final embedded cost rate will be the actual embedded cost as of May 31, 2024, the last month of the test year. In addition, as explained in more detail later in my testimony, the Company is seeking to defer any change in the embedded cost of debt after the test year given the volatile interest rate market.

E. Appliance Service Business

Q. Has the Company's Appliance Service Business helped to reduce rates?

A. Yes. PSE&G is the only utility in the State that continues to have an Appliance Service Business ("ASB") within the utility structure. As a result of this structure, the majority of the

pre-tax earnings of this business are captured in the revenue requirement-setting process of each PSE&G base rate case, including this one. As discussed in more detail below, the Company is proposing to retain 50% of the Gas ASB margins in this proceeding in the same manner as allowed for an Electric utility under the New Jersey Administrative Code. Even with the proposed 50% sharing of all ASB margins, the test year reflects a significant benefit to Electric and Gas customers of approximately $46 million of margin (revenue less expenses) that will offset PSE&G's revenue requirement and is comparable to the margin returned to customers in the last base rate case.

F. Summary Impact of Cost Savings

Q. Please summarize the cost mitigation efforts the Company has accomplished to limit the rate request in this proceeding.

A. The Company has been very successful in controlling costs to limit the impact to customers. While an increase is unavoidable, PSE&G has taken notable steps to limit the impact: 1) PSE&G is the only utility in NJ flowing back significant tax credits to benefit customers, allowed by the Company's strong balance sheet and disciplined cash management; 2) the Company's P&OPEB currently remains a credit to customers, even with the recent downturn in markets; 3) PSE&G is the only NJ utility still providing ASB through the utility, representing a significant benefit to customers in net margin and operational savings; and 4) PSE&G continues to contain utility expenses to reduce the inevitable increase in expense due to inflation and wage increases. PSE&G has been able to accomplish this without sacrificing reliability and customer satisfaction. This is exemplified in the testimony of Mike Adams on how PSE&G compares to its peers in cost, reliability, and customer satisfaction.

V. CAPITAL STRUCTURE AND THE COST OF CAPITAL

Q. Does PSE&G have a need to maintain sufficient financial integrity to raise capital effectively?

A. Yes. The Company's financial integrity depends on, among other things, an approved return on equity ("ROE") that reflects the cost of capital required by investors, and a capital structure that is supportive of the Company's strong credit quality. The current authorized ROE is 9.60% and was set in the Company's last base rate case. As Company witness Ann Bulkley testifies, the Company's overall ROE should be reset at 10.4%, reflecting current market and business conditions. PSE&G proposes to apply its ROE to a capital structure reflecting a common equity component of 55.5%, to support targeted credit statistics, maintain a strong investment grade credit rating, and earn a just and reasonable return for investors.

Q. What is the Company's cost of capital and on what capital structure is PSE&G seeking to have those cost rates applied?

A. PSE&G seeks an overall rate of return of 7.55% that is derived from a capital structure composed of 55.5% equity, 44.29% long-term debt, and 0.21% customer deposits. The embedded cost rate for the Company's long-term debt is estimated to be 4.02% by the end of the test year. Customer deposits are accumulated at a rate of 1.40% as of January 1, 2023. The proposed ROE is 10.4%, as discussed in Ms. Bulkley's testimony.

A. Return on Equity

Q. How did Ms. Bulkley determine an appropriate cost of equity?

A. Ms. Bulkley derived her cost of equity using an analysis of a proxy group of companies that receive a similar percentage of operating income from regulated operations as PSE&G, and possess a set of operating risk characteristics that are substantially comparable to the

Company. She then estimated the Company's Cost of Equity ("COE") by applying several traditional COE estimation methodologies to a proxy group of comparable utilities, including Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. The COE estimation models produce a wide range of results. Based on this analysis, Ms. Bulkley established a range of 10.00% to 11.00% as reasonable and recommended 10.40% based on underlying market conditions and the business, financial, and regulatory risk factors facing PSE&G, including the Company's significant capital expenditures.

Q. Beyond the results of Ms. Bulkley's COE analysis, is there anything else the Board should consider?

A. Yes. While the Company fully supports Ms. Bulkley's analysis and 10.4% ROE recommendation, PSE&G also recognizes that COE estimation models are complex, with each methodology resulting in a wide range of results and different consultants can have different results based on the assumptions employed for each test. In the Company's 2009 base rate case, the parties to the proceeding settled to a 10.30% ROE and in 2018 settled to a 9.60% ROE, both of which were approved by the Board. Without getting into the complexity of each COE methodology, below is a summary of the market conditions for the current and prior PSE&G rate case:

Table 3

Change in Market Conditions Since Company's Last Rate Case					
PSE&G Rate Cases	**Decision Date**	**Federal Funds Rate**	**30-Day Average of 30-Year Treasury Bond Yield**	**Core Inflation Rate**	**Authorized / Proposed ROE**
2018 Rate Case	10/29/2018	2.20%	3.29%	2.13%	9.60%
2023/24 Rate Case	10/31/2023	5.33%	4.84%	4.13%	10.40%

Q. How do these factors impact a utility's ROE?

A. As described in the testimony of Ms. Bulkley, these factors impact the assumptions on risk used to calculate the COE methodologies. At a high-level, a US Treasury bond is considered risk-free and thus a premium above that rate would be needed for any investor to invest in PSE&G over a risk-free treasury bond. As interest rates rise, utility stocks can become less desirable as the premium needed to take on the additional risk declines. As a result, it would be expected that the ROE would increase as interest rates are increasing. Also, in terms of risk, the high Federal Funds Rate and Inflation rate indicate more risk to investors in the future as costs (and interest rates) may continue to rise. As such, market conditions require higher equity returns than at the time the 2018 ROE was approved.

Q. Is there more uncertainty surrounding the electric and gas utility industries in NJ compared to the last rate case?

A. Yes. There have been several BPU Orders, Governor's Executive Orders, legislative acts, and the Energy Master Plan focused on significant expansion of electric vehicle adoption, solar targets, electrification, and the future of the natural gas business as the State promotes the transition to a cleaner environment. PSE&G supports the State's promotion of the transition to a cleaner environment, and it can present opportunities for growth for the Company. However, it also represents significant uncertainty and risk to investors. The BPU is preparing to initiate a proceeding on the future of the natural gas industry. While the electric business has growth opportunities, the significant expansion of electric vehicles and conversion of gas heating to electric will require significant capital investment to ensure the reliability of the distribution system as customers depend on it more than ever. Capital investment will also be required to account for increasing amounts of supply coming from cleaner, more distributed sources as well as potential shifts in the Company's peak. The

uncertainty of the impacts of the transition on the utility industry should be taken into consideration when determining the Company's risk and ROE.

Q. Are there any other factors that should be considered by the Board in determining the Company's ROE?

A. Yes. The Company's exemplary operating performance should be considered. As noted above and more extensively in Mr. Adams' testimony, PSE&G has delivered top quartile service (reliability) and customer satisfaction, at the lowest O&M and A&G costs compared to NJ and other peers.

B. Capital Structure and Credit Ratings

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The Company is targeting a capital structure having a 55.5% equity ratio, because this ratio is important to provide support for PSE&G's current credit rating. PSE&G is committed to strong investment-grade credit ratings in order to ensure consistent access to the capital markets at reasonable costs. PSE&G ended 2022 with a 55.1% equity ratio and its current senior secured credit ratings are "A" from S&P and "A1" from Moody's; the credit rating outlooks are stable from both rating agencies. The Company plans to manage its capital structure consistent with its equity ratio approved for ratemaking, so would expect to move toward 55.5% later in 2024. The 55.5% equity percentage was determined by evaluating the equity level needed to maintain certain credit statistics (i.e., Funds from Operation to Debt ("FFO to Debt"), or as Moody's calculates, Cash flow from Operating activities – pre working capital ("CFO pre-WC") to Debt) for a sustained period. Moody's credit opinion indicates that the FFO to Debt range for PSE&G's current rating is between 17% and 20%. While a 54% equity ratio was approved in the 2018 base rate case, the Company has increased its equity

ratio to support its credit rating. The Company seeks approval of a 55.5% equity ratio to maintain strong credit ratings in a volatile market environment.

Q. Why is it important to maintain the Company's current credit ratings?

A. PSE&G has approximately $14 billion of long-term debt outstanding as of October 31, 2023. PSE&G also has a significant capital program and several billion dollars of long-term debt maturing in the coming years. Strong credit ratings are essential to executing financing plans and accessing the capital markets on reasonable terms at all times, especially during periods where market volatility can be prevalent. Volatility can limit market access and increase credit spreads.

Markets have experienced significant volatility in recent years that continues to persist. In March 2020, capital markets were not accessible due to uncertainty related to the COVID-19 pandemic. It required substantial government intervention to restore confidence and re-open markets. In early 2022, the Federal Reserve began to battle high levels of inflation, causing significant market uncertainty as rising interest rates impacted the economy. During 2022, volatility translated into periods of reduced market access, where issuers needed to be concerned with "actionable" days. In 2022, a considerable number of the business days were not "actionable", resulting in issuers competing more intensely for capital during periods when markets were open. Later in March 2023, markets were not accessible due to a crisis of confidence in the banking system. Intervention by the Federal Reserve to backstop deposits and assume responsibility for failed banks was required to help stabilize markets. Markets re-opened to issuers but continue to remain susceptible to further developments that could impact the regional banking sector. Impacts to the bank sector have the potential to spill over to the wider economy. Overall, market conditions remain characterized by volatility and are highly

susceptible to political, banking, and economic developments, and have proven very dependent on economic data and Federal Reserve response.

The Company has had a strong history of raising low-cost financing, which has directly benefited customers in the form of lower interest expense – both in its infrastructure filings as well as this base rate case proceeding. As noted previously, the Company's cost of debt has remained relatively constant since the 2018 base rate case. This value translates into keeping customer rates low. Overall, preserving the Company's current credit ratings is the most desirable course of action for the reasons cited above, including the importance of executing the Company's debt financing plan during volatile periods.

Q. What key metrics and factors do the rating agencies assess in determining the Company's credit rating?

A. Funds from Operations to Debt (FFO/Debt) represents a key credit measure used by the ratings agencies. Moody's refers to FFO / Debt as CFO pre-WC to Debt. FFO/Debt is a measure of cash flow leverage and indicates a company's ability to support its debt level. For the purpose of demonstrating sound financial management, PSE&G tends to focus on the calculation of FFO to Debt from Moody's more so than S&P's calculation. S&P's analysis follows a "family" approach that develops a corporate credit rating based on a consolidated business and financial profile. S&P uses a top-down approach; Moody's, in contrast, uses a bottom-up approach, which analyzes the business and financial profile of an entity. Given this approach, Moody's credit opinion provides the more useful insights into a subsidiary credit rating.

Q. How has your credit rating changed since the last rate case in 2018?

A. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. PSE&G's senior secured credit ratings from Moody's of A1 and S&P of A are now both in the same 'A' rating category. The below table reflects PSE&G's Senior Secured ratings since 2018:

Table 4

Year – End	S&P	Moody's
2018	A	Aa3
2019	A	Aa3
2020	A	Aa3
2021	A	A1 (one notch downgrade)
2022	A	A1
2023 (Current)	A	A1

Q. What factors led to the downgrade in the Company's credit rating?

A. As indicated during the 2018 base rate case, federal tax reform in 2017 was credit negative for regulated utilities including PSE&G. The loss of bonus depreciation and the decision to flow back excess deferred income taxes to customers placed downward pressure on credit metrics. Moody's credit research referenced weakening financial metrics with limited financial cushion for PSE&G. In 2020, the decline in CFO pre-WC to Debt below the downgrade threshold of 19% was notable driven by impacts related to Tropical Storm Isaias and COVID-19. In May 2021, Moody's changed PSE&G's credit rating outlook from stable to negative, noting the decline in metrics. In October 2021, Moody's downgraded PSE&G's rating on senior secured debt to A1 from Aa3. Since 2021, PSE&G's credit ratings have

remained unchanged while the Company has executed substantial capital programs, supported by a regulatory equity ratio of 55.1% at year-end 2021 and year-end 2022, with a plan to manage capital structure consistent with an equity ratio approved for ratemaking, so would expect to target 55.5% later in 2024.

Q. Has PSE&G managed its finances to maintain a strong credit rating?

A. Yes. PSE&G has managed to maintain a strong credit profile. This has been achieved through disciplined financial management, including limited dividends to the parent company Public Service Enterprise Group ("PSEG"). From 2019 through 2022, PSE&G demonstrated disciplined financial management while experiencing storms, most notably Tropical Storm Isaias, and the COVID-19 pandemic. As a result of these events, PSE&G incurred significant unexpected costs. These incremental costs were financed consistently with PSE&G's capital structure, which required more retained equity. In addition, PSE&G increased its equity ratio to 55% from 54%, which required more retained equity.

Q. Has Moody's threshold for a credit upgrade or downgrade changed since the last rate case?

A. Yes. Moody's updated its upgrade threshold for CFO pre-WC to debt. In summary, Moody's "raised the bar" for the "Aa3" rating from 19% to 20%. See the table below.

Table 5

Moody's CFO pre-WC to debt			
	Senior Secured Credit Rating	Factors that could lead to an upgrade	Factors that could lead to a downgrade
June 2018	Aa3	excess of 26%	falls below 19%
October 2023	A1	above 20%	below 17%

Moody's credit opinion on PSE&G from October 2023 includes the following:

> **Factors that could lead to an upgrade**
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful improvement in the utility's business risk and that there is greater certainty and visibility for the utility's cash flow generation, the rating could be upgraded.
>
> A rating upgrade could be considered if PSE&G's financial profile improves such that its CFO pre-WC to debt, including the adjustment related to energy efficiency investment, is maintained above 20% on a sustained basis. In addition, if the regulatory environment improves, resulting in a meaningful decrease in the utility's business risk and greater certainty and visibility with regard to the utility's cash flow generation, the rating could be upgraded.
>
> **Factors that could lead to a downgrade**
> A downgrade could be considered if the regulatory environment deteriorates such that the regulatory lag increases significantly. In addition, if its CFO pre-WC to debt ratio, including energy efficiency investment, remains below 17%, its rating could be downgraded.

Q. Has Moody's conveyed its expectation of the CFO-pre-WC to debt ratio it intends PSE&G to retain to maintain its current rating?

A. Yes. In the PSE&G Credit Opinion from October 2023, Moody's included the following:

> PSE&G is pursuing a substantial capital investment program over the next five years that will grow its rate base. We expect its cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, including the adjustment related to its energy efficiency spending, to be around 18% over the next two to three years.

At year-end 2022, "CFO pre-WC" to Debt was approximately 18%, while the regulatory equity ratio was approximately 55%. A 55% regulatory ratio was important to help deliver Moody's expectations of CFO pre-WC to debt, as referenced in its credit opinion from October 2023.

Q. Do you believe the current approved equity percentage of 54% is sufficient for PSE&G to maintain its current credit rating?

A. PSE&G's current credit rating would be challenged at the 54% equity ratio, which prompted the Company to increase to 55.1%. PSE&G has been gradually increasing its equity ratio above 54%, which was approved in the 2018 distribution base rate case, as we have sought to support PSE&G's credit profile. As shown in the table below, our FFO to debt ratio dropped below the 17% floor in 2020 and increasing PSE&G's regulatory equity ratio to over 55% has been an important measure to help support the current credit profile.

Table 6

Year	Year-End Regulatory Equity Ratio	Moody's CFO pre-WC to Debt
2019 Actual	54.6%	18.2%
2020 Actual	54.5%	16.7%
2021 Actual	55.1%	17.5%
2022 Actual	55.1%	18.1%

Q. Has the Company informed Board Staff or the New Jersey Division of Rate Counsel ("Rate Counsel") that it was increasing its common equity percentage above the approved amount in the last rate case?

A. Yes. In July 2021, PSE&G reached an agreement to lower transmission rates with the Board and Rate Counsel. During the settlement process, PSE&G advised the parties that the Company would increase its equity ratio from 54% to approximately 55% due in part to the lower cash flows due to the reduction in the Transmission ROE agreed to in the settlement. At the end of 2021 and 2022, PSE&G's equity ratio was 55.1%. The actual regulatory equity ratio will vary monthly based on monthly earnings and financing activities.

Q. Please explain the basis for the 55.5% equity ratio sought by the Company.

A. The 55.5% equity target was determined by evaluating the capital structure needed to maintain key credit statistics for a sustained period. More specifically, Moody's credit opinion indicates that the CFO pre-WC to Debt range for PSE&G's current rating is between 17% and 20%. The 55.5% equity ratio is expected to support an FFO/Debt level that targets the upper end of the guidance for our credit metrics, which includes sufficient cushion above the low end of the range (17%) for downside risks.

Q. Why is it important to target above the 17% floor for the credit rating range?

A. As made evident by the last four years, unexpected events will impact the Company's cash flow, most recently major storm events and the COVID-19 pandemic. To illustrate the need for some financial flexibility, in 2020 Tropical Storm Isaias and the COVID-19 pandemic adversely impacted the Company's CFO pre-WC to Debt by approximately 2.5%. While those events will not occur every year, unexpected events that impact cash flow can and will occur, so it is important to maintain sufficient cushion above the 17% threshold to help protect the Company's credit profile against unexpected events and cash flow uncertainty.

Q. Are there other factors besides unexpected events that support increasing common equity to 55.5%?

A. Yes. First, PSE&G is unique in the State in flowing back significant tax benefits. This is a significant benefit to customers (and revenue reduction to the Company) of over $200 million per year on average since 2019. The Company is able to flow this amount back to customers because of its disciplined financial management but it does impact the Company's cash flow, and given the size of the credit to customers, any lag in adjusting rates can cause a notable impact on the Company's cash flow. PSE&G also has the highest proportion of low-

income customers compared to the other electric and gas utilities in the State and experienced a significant impact on collections during the COVID-19 pandemic, with its Accounts Receivable balance greater than 90 days increasing from $116 million in March 2020 to $442 million in March 2022, an increase of more than 350%, far more than any other New Jersey utility experienced. Finally, PSE&G forecasts a substantial capital program to modernize its system to meet the State's clean energy goals and maintain safe and reliable service.

Q. Can you summarize the basis for the requested 55.5% common equity ratio?

A. Yes. PSE&G has demonstrated strong financial management to support strong credit ratings in a very challenging environment. However, recent years have shown that the 54% common equity amount approved in the last rate case is not sufficient, as PSE&G has proactively increased its common equity ratio to above 55% to support a FFO/Debt ratio to support the Company's credit profile. A 55.5% equity ratio allows PSE&G to better manage a substantial capital investment program, flowing back excess deferred taxes, and to account for unexpected events, such as major storm events, that are becoming more frequent and can have a significant impact on cash flow. The Company forecasts a substantial capital program necessary to meet State goals and maintain safe and reliable service and must have access to financial markets to fund those investments at the lowest rates possible. Maintaining the current credit rating will ensure the best possible execution of PSE&G's financing plans under a range of possible market conditions, and therefore it is critical that the Board approves a 55.5% common equity ratio to support PSE&G's credit profile.

VI. APPLIANCE SERVICE BUSINESS ("ASB")

Q. Can you briefly describe the Appliance Service Business?

A. PSE&G has been servicing appliances in its territory for over a century. The current services offered are for:

1) Appliance Repair Service and Maintenances Services, referred to as "APSO";
2) Replacement Parts Service Contracts, referred to as "Contracts";
3) Water Heater Replacement; and
4) Central Heating and Central Air Conditioning Replacement ("HVAC").

The majority of the work is performed by PSE&G's workforce with the exception of water heating replacement, which is conducted by contractors retained by the Company.

Q. How is the margin from ASB treated for ratemaking?

A. The revenues and expenses associated with the appliance service business are included in the income statement for the utility. The margin (revenues less expenses) in the test year is included for ratemaking purposes in accordance with *N.J.A.C.* 14:4-3.6(r), which has separate regulations for electric and gas utilities. For gas public utilities, the total ASB margins are currently treated above-the-line for ratemaking purposes and credited to customers. For electric public utilities and related competitive business segments of electric public utilities, 50 percent of the total margins are recorded in respective competitive service revenue accounts and treated above-the-line for ratemaking purposes.

Q. Since PSE&G is both an electric and gas utility, how are margins split between the two businesses?

A. In the 2018 rate case, the revenues and expenses were split between electric and gas based on the fuel type for the appliances under contract and being repaired or replaced. Starting

in 2023, PSE&G has modified that approach to allocate ASB margins based on a pre-set 55% electric and 45% gas allocation.

Q. Why change the allocation methodology?

A. There are a few reasons why a pre-set allocation is more appropriate at this time.

First, for ratemaking purposes, it adjusts the calculation as if PSE&G consisted of standalone electric and gas utilities for allocating the net benefit of the business. A customer in PSE&G's electric-only service territory can have services for gas appliances, and vice versa. In this instance where an electric-only customer has work completed on gas appliances, that customer is contributing to the net ASB margins, but none of that credit is flowing back to that customer as it will be allocated to PSE&G's gas customers only. The pre-set allocation based on number of customers adjusts the allocation as if we were stand-alone electric and gas utilities and is the same allocation applied to Common Plant for decades. Also, since the approval of the CIP after the 2018 rate case, the primary driver of margin for the utilities is the number of customers, since the CIP is calculated on a per customer basis. Switching to an allocation based on the number of customers aligns the ASB margin with the driver of margin for the electric and gas utility.

Second, the allocation by appliance fuel type does not factor in the nature of the service being provided. While the majority of ASB margins are allocated to the gas utility based on appliance fuel type, the majority of the materials being replaced for the Contract and APSO services are for electrical components. Based on recent history, approximately 60% of the parts repaired and replaced for gas-fueled appliances are for electric components. While using this approach would still directly allocate margins between electric and gas based on the work performed, it would significantly shift ASB margin from gas to electric and create the same

cross-subsidization issue as the current allocation by fuel type. For these reasons, PSE&G did not implement this approach, but it supports allocating more margin to electric, which the Company is doing to a lesser extent by allocating based on the number of customers.

Finally, the allocation methodology takes into consideration the State's policy goals targeting increased electrification. The allocation of ASB margins between electric and gas customers in the 2018 rate case was approximately 35% to electric and 65% to gas. That allocation is expected to increase by the end of the test year to approximately 40% electric and 60% gas if margins were allocated by appliance fuel type. As the State moves toward electrification, it is likely the allocation to electric appliances will continue to increase. Since ASB margins are allocated to customers based on the test year amount in a rate case, electric customers will not receive any benefit from the shift in allocation between electric and gas until a subsequent rate case. Implementing the pre-set 55% Electric and 45% Gas allocation at this time will credit electric customers now with the expected shift to more electric appliances in the short-term and will help lower costs to electric customers where costs are expected to increase while the State pursues its electrification and clean energy goals. While PSE&G made this allocation change in 2023, the Company will continue to monitor the driver of the ASB margins and the most appropriate allocation to customers in the future, especially as the electric and gas utilities evolve to meet the State's clean energy goals.

Q. Does ASB provide a benefit to PSE&G's customers by being part of the utility?

A. Absolutely. ASB provides significant financial and operational benefits to customers.

Financial benefits of ASB. The margins from this business help reduce costs to all our customers. For this test year ending May 31, 2024, PSE&G projects annual net margins of $46 million ($25 million to electric and $21 million to gas) to be returned to customers,

reducing the annual revenue request in this proceeding. As a reduction to base rates, that amount will be implicitly refunded to customers every year until the conclusion of the Company's next base rate case, when the amount will be reset. This is a significant benefit to customers and includes the proposed retention of 50% of gas margins discussed in more detail below.

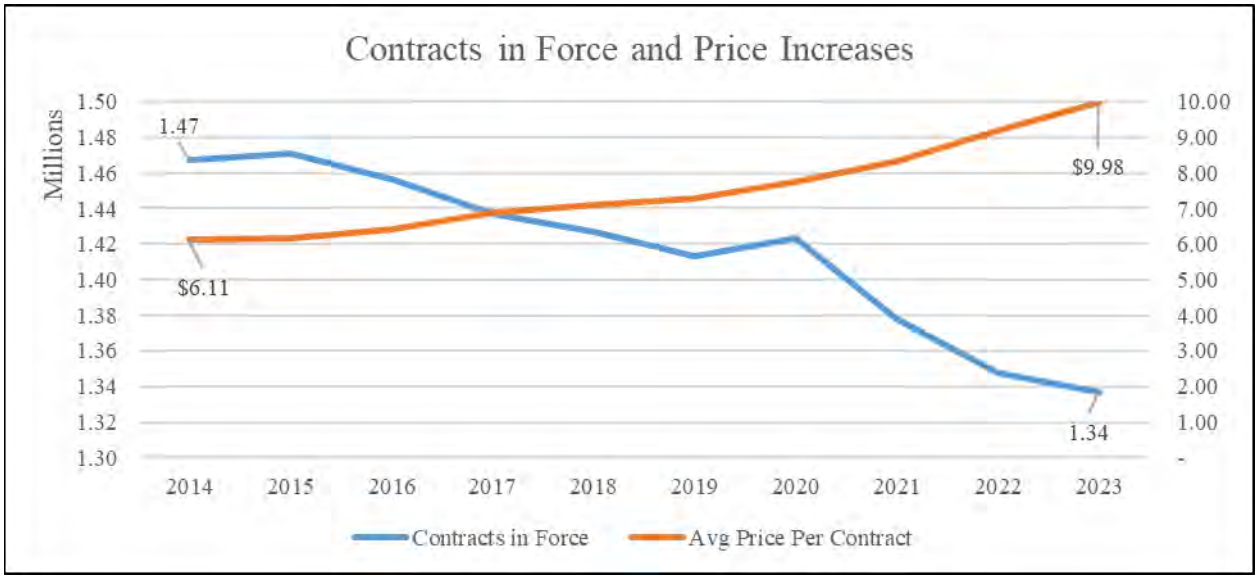
Operational benefits of ASB. Having ASB in the utility also has operational benefits. Appliance service technicians are skilled labor that also perform emergency response duties (including responding to emergency calls about gas leaks, carbon monoxide, and fires) as well as meter services, such as meter installations and replacements, and turn on and shutoff services. This work is referred to as regulatory work and the majority is on emergency response in the peak winter season. If not for the ASB Competitive Service business, the Company would have inefficiencies with the workforce due to the inconsistent nature of the work that is weather driven. For example, there are a greater volume of gas leak and appliance diagnostic responses in the winter months as compared to the non-winter months. The need to staff for the peak workload would result in a material increase in costs to our customers.

Q. Are there challenges in increasing ASB margins going forward?

A. Yes. PSE&G has been very successful in managing this business, which has benefited customers through a revenue reduction from margins and through more efficient workforce management. However, the number of customers purchasing Contract services has been declining. Other than a temporary increase in 2020, the number of customers purchasing Contracts services has been in decline since 2015. On top of a decline in demand for the business, the Company faces challenges in the supply chain, leading to cost increases and part shortages. While PSE&G can continue to increase Contract prices to offset the costs, the

increases only occur once each year and will likely result in a reduction in customer contracts, creating more margin risk. Despite these challenges, PSE&G has been able to increase margins through price increases, and growth in the HVAC business since the last rate case. However, yearly price increases are not a long-term strategy, as continual increases will only hasten the decline in the number of customers.

Chart 14



Q. Are there challenges amplified by the current ratemaking structure?

A. Yes. As mentioned above, the ASB margins included for ratemaking purposes follow *N.J.A.C.* 14:4-3.6(r), which requires 50% of electric margins and 100% of gas margins in the test year returned to customers. Once included in rates, the Company is essentially refunding that amount to customers every year until the margins are reset in a future rate case. As a result, if ASB margins drop below the amount in the test year, the Company would lose money as a result of continuing this business.

Q. How does the Company propose to address this challenge?

A. The Company proposes to retain 50% of the total net margins from the provision of ASB services to its gas customers in the same manner as allowed for its electric customers. While *N.J.A.C.* 14:4-3.6(r) provides rules for ratemaking for electric utilities and gas utilities, it does not specify the treatment for a combined electric and gas utility and the Board can approve this ratemaking treatment to account for the uniqueness of PSE&G's combined electric and gas business. The Company believes that good cause exists for the BPU to approve this ratemaking treatment for the following reasons:

- Given the decline in ASB customers since 2020, the Gas ASB represents more risk than reward going forward;
- The request to retain 50% of the margins is consistent with the ratemaking already allowed for electric margins;
- ASB would still represent a $46 million reduction to our requested annual revenue increase, even at 50% margins for both Electric ASB and Gas ASB;
- Maintaining ASB in the utility provides operational benefits to customers by reducing staffing needs that would only be used for emergency work in the winter period; and
- As the only utility in NJ still providing this service, the N.J.A.C. regulations apply only to PSE&G, but they do not address a combined electric and gas utility.

PSE&G is proud of this business, its skilled workforce, and the value that it generates for customers, both through direct financial benefit in the ratemaking process, and through support of the important services we provide, particularly during emergencies and in challenging weather conditions. However, if there is more risk than reward potential

associated with this business, PSE&G will be forced to consider restructuring or exiting this business.

VII. P&OPEB EXPENSE RECOVERY

Q. Is the Company proposing a change in the accounting treatment of P&OPEB expense (or income) in this proceeding?

A. Yes. The Company proposes that any volatility in the P&OPEB income (or expense) above or below the amount set for recovery in this proceeding be deferred for recovery or refund in a subsequent rate case proceeding.

Q. Please briefly describe P&OPEB accounting.

A. Pension expense represents an employer's annual cost for maintaining employees' pension benefits, while OPEB expense reflects the annual expense recognition for retiree healthcare and other post-retirement benefits. Employers that provide a pension plan must calculate and disclose plan assets and liabilities on the balance sheet, and record pension expense on the income statement. Pension expense is comprised of individual components calculated by the plan's actuary. These components include service cost (the P&OPEB earned by employees who are active in the relevant year), interest cost, expected return on plan assets, and amortizations of both prior service cost and actuarial gains / losses.

Q. How are these P&OPEB components reflected on the income statement?

A. The Service Cost component of expense is reflected in the operating section of the income statement. The other components of expense are reflected in non-operating earnings for GAAP. This accounting treatment is due to the concept that the Service Cost component of expense reflects the cost associated with pension benefits earned during the year. The other components of expense are mostly related to the plan's assets, liabilities, historical plan

changes, and actuarial assumptions, and are impacted by financial market performance and interest rates. For ratemaking purposes, all components are included as operating and recovered or refunded to customers.

Q. What is the funding level of the Company' pension obligation?

A. As of July 31, 2023, the qualified pension plans were funded at approximately 93%.

Q. Has the Company been successful managing the investment strategy of the pension asset?

A. Yes. As I have stated previously, the Company has been very successful in managing the investment strategy of the pension assets, as illustrated by the expected P&OPEB income of approximately $9 million for 2024 ($8 million of pension income and $1 million of OPEB), which is positively impacted by the funded status of the pension plans (difference between pension liability and pension assets). This estimated income is after accounting for the Board's February 2023 Pension Accounting Order. If not for the Pension Accounting Order, the projected P&OPEB income would decline by $55 million in 2023 and become an expense.

Q. Can there be significant annual fluctuations in the pension non-service income?

A. Yes. The pension non-service income is subject to market performance and given the size of PSE&G's pension assets and liabilities, can reflect significant annual changes.

Q. How did the Board's Pension Accounting Order address the volatility of pension costs?

A. In its February 2023 Pension Accounting Order, the Board granted PSE&G the authority to use a calculated value that recognizes changes in fair value in a systematic and rational manner, to "smooth" returns on assets in the Company's pension trust, for purposes of calculating the amortization of net gain or loss component of pension expense. This

methodology change results in a timing difference between PSE&G's recognition of the impact of changes in the market-related value of assets in calculating its pension expense for ratemaking purposes versus its current methodology. PSE&G was therefore authorized to (1) record a regulatory asset or liability to account for the difference in the amortization of net gain or loss component of pension expense (or income) between PSE&G's current methodology and this alternative methodology ("smoothing"), and (2) submit for recovery or return in rates the pension expense or income utilizing the proposed methodology for computing the amortization of net gains or losses. Adopting a calculated method for determining the market related value of plan assets in PSE&G's pension trust for purposes of calculating pension expense, like the majority of PSE&G's peer companies and the State of New Jersey itself, will reduce the volatility of PSE&G's income statement and customer rates; improve the usefulness of the information presented to financial statement users; and improve comparability of results for PSE&G and its peers.

Q. Does the Pension Accounting Order address the volatility in pension non-service income?

A. While the Pension Accounting Order does reduce the volatility resulting from market fluctuations, there remains significant volatility that can occur based on market changes. The Pension Accounting Order only impacts the gain or loss amortization component of expense. There remains significant cost volatility with respect to the expected return on assets component of pension expense.

Q. How does the Company's proposal address this volatility?

A. The proposal would defer any variances between the required actuarial expense/income recorded on the FERC income statements and the amount refunded to customers as a result of

this proceeding. This would ensure that neither the customers nor the Company would win or lose based on market fluctuations outside of the amount refunded to customers in this case.

Q. Does this proposal just shift market performance risk to customers?

A. No. While it would allow for recovery of a decline in P&OPEB income, it would also allow an increase in the refund of market gains as well. Fluctuations will occur both up and down and this proposed accounting treatment will ensure variances are equally shared.

Q. Does this proposal incent PSE&G to take excessive risk with its pension investments?

A. No. The management of the investments of the pension plan are subject to fiduciary standards that require the highest level of prudence and care, and all decisions are made in the best interests of plan beneficiaries. In fact, a glide path strategy for the investment allocation of PSE&G's pension asset was adopted and designed to reduce risk by increasing fixed income investments as the funded status of the plan improves. In addition, the pension and OPEB programs cover non-PSE&G employees, whose pension costs are not subject to rate recovery. The Company is therefore incented to manage the entire pension plan to ensure optimal financial results.

Q. Is there precedent in New Jersey for this accounting treatment?

A. Yes. New Jersey American Water utilized deferred accounting for P&OPEB expense in its most recent rate case, deferring any change from the amount proposed in rates in the same manner as PSE&G proposes in this proceeding.

VIII. GAS BAD DEBT RECOVERED IN SBC CLAUSE

Q. How are gas bad debt expenses currently recovered from customers?

A. Gas bad debt expenses are currently recovered in base rates. An average uncollectible rate is included in the revenue factor used to gross-up the revenue increase request in the Company's prior base rate case as well as in post rate case infrastructure program rate adjustments and the gas TAC. There is no true-up between the actual gas bad debt expense incurred and the recovery through base rates (and the TAC).

Q. Does the recovery of gas bad debt expense treatment differ from the recovery of electric bad debt expense?

A. Yes. Electric bad debt expense is recovered through the Social Programs component of the electric Societal Benefits Charge.

Q. Are there any differences between the two businesses that warrant the separate treatment?

A. No. The majority of PSE&G's customers are combined electric and gas customers, so non-payment would impact the Accounts Receivable balance of both businesses, in the same manner. Setting aside the different mechanisms for recovery, there is no difference to PSE&G between non-payment from an electric customer and a gas customer or a combined electric and gas customer, as in all cases it is cash not received by the Company. It would be more logical and less confusing to use the same recovery mechanism without regard to which business the Accounts Receivable balance is attributed.

Q. Which recovery mechanism is better?

A. Recovery of bad debt expenses through the SBC, as is done for the electric business, is the most appropriate method. Through the SBC, all bad debt expenses can be reviewed for

prudency and only prudently incurred costs are recovered. Conversely, with base rate recovery, there will always be a mismatch between bad debt expense recovered and the expense incurred so the Company is either recovering too much or too little.

Q. What is PSE&G's proposal in this proceeding?

A. As described in the testimony of Mr. Swetz in the COVID-19 proceeding in BPU Docket No. AO20060471, the Company proposes that gas bad debt expenses be recovered through a new Social Programs component of the Gas SBC, consistent with the recovery of electric bad debt expense. For details on the proposed new component of the Gas SBC, please see the testimony of Mr. Stephen Swetz. See Schedule MPM-46 for a *pro forma* adjustment to remove the recovery of gas bad debt from the rate case request so that it can be recovered in the proposed new Social Programs component of the Gas SBC.

As a result of the COVID-19 Order, PSE&G and other New Jersey utilities were permitted to defer the significant increase in gas bad debt expense above the amount included in base rates from March 9, 2020 through March 15, 2023. The Company's proposal in this proceeding does not include deferred COVID-19 bad debt which is being addressed in a separate proceeding.

IX. STORM COST RECOVERY

Q. Has PSE&G incurred any major storm expenses since the last base rate case in 2018?

A. Yes. As discussed in more detail in the panel testimony of Mr. Schmid and Mr. Fonseca, the Company has incurred approximately $109 million in incremental O&M expense for preparation and/or restoration efforts associated with five major storm events from July 2018 through November 30, 2023.

Q. What is the definition of a "Major Storm Event"?

A. A Major Storm Event is defined in N.J.A.C. 14:5-1.2 and includes a weather event such as a thunderstorm, tornado, hurricane, heat wave, snow, or ice storm which either affects at least ten percent of the customers in one of the Company's operating areas or results in the declaration of a state of emergency. As discussed in more detail below, the Company is proposing to expand the definition for Major Storm Event costs to include prudent, significant pre-staging costs that are incurred in preparation for a projected Major Storm Event that may not ultimately occur.

Q. How does the Company currently account for the incremental O&M costs associated with Major Storm Events?

A. Consistent with the way in which the Company has accounted for incremental O&M costs associated with Major Storm Events since 2010, the Company defers these costs for future recovery in a manner to be determined by the BPU.

Q. Were base rates set to recover any Major Storm Events that occurred after the conclusion of the 2018 base rate case?

A. No. In the 2018 base rate case, the Company used a *pro forma* adjustment to remove the $25.247 million in Major Storm Event incremental O&M that occurred in the July 2017 through June 2018 test year in that proceeding.[19] As a result, there is no base rate recovery of incremental O&M for post 2018 Major Storm Events in the Company's current base rates.

[19] Schedule SSJ-40 R-2, of Exhibit P-2 12+0 Testimony of Scott Jennings from the 2018 base rate case (*I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030 (filed January 12, 2018)).

Q. Is the Company proposing to use deferral accounting for Major Storm Event costs rather than base rate recovery?

A. Yes. The use of deferral accounting for the costs ensures that customers will pay no more and no less than the Company's actual costs associated with events that are beyond the Company's control and impossible to predict. This protects both the Company and customers. For example, assume the test year Major Storm Event costs were reflected in base rates instead of deferral accounting. Customers would have been paying over $25 million in rates even if no Major Storm Events occurred, such as in 2022. While the Company would have the benefit of collecting above actual costs in all years but 2020, in that year it would have incurred a massive loss due to the over $87 million in deferred costs incurred as a result of Tropical Storm Isaias. The Company should not profit from the absence of Major Storm Events, nor should it be penalized for prudently incurred incremental expenses associated with Major Storm Events.

Q. Is the Company proposing any changes to Major Storm Event recovery in this proceeding?

A. Yes. Deferral accounting, coupled with an annual surcharge mechanism, is the most appropriate means of recovering Major Storm Event costs by protecting the Company from significant financial harm from major weather events outside its control as well as ensuring customers only pay for actual, prudently incurred costs. First, this would allow for a prudence review of the deferrals within a reasonable time after they are incurred instead of reviewing all Major Storm Events that occur between rate cases at the same time. Second, these interim rate proceedings can help the Company maintain its credit ratings (which have benefited customers) as well as prevent any rate shock that could arise if the Company were permitted to recover the costs of all post-test year events at the same time. Finally, the use of a surcharge provides a mechanism to stop the amortization when recovery of the deferral is completed. As

a result, the Company is proposing that a new clause, "the Storm Recovery Charge," be created to recover the approximately $109 million in deferred storm costs incurred since the last rate case as well as any future prudently incurred storm costs. For more details on the new clause, please see the testimony of Company witness Mr. Swetz.

Q. Are you proposing any other change to the manner in which costs associated with major storm events are recovered from customers?

A. Yes. Based upon the severity of weather forecasts, the Company may prepare in advance for a storm by procuring and/or mobilizing contractor crews prior to the onset of adverse weather, with the intention of deploying those crews to shorten the duration of customer interruptions. Given the difficulty of moving people and equipment under adverse weather conditions, and the competition among regional utilities to secure adequate emergency support when storms are forecast, the Company simply cannot wait until the impact of an imminent storm is certain; by then it is too late. Therefore, "pre-staging costs" must be recoverable, including any costs to retain contractors to assist with restoration efforts that would otherwise leave for storm duty in another jurisdiction. If the actual weather does not end up meeting the definition of a Major Storm Event, the Company should nonetheless by provided an opportunity to recover prudently incurred "pre-staging costs" incurred to respond to potential storms. The Company proposes that under the Major Storm Events cost recovery clause that it is proposing in this proceeding, it should be permitted to include recovery of pre-staging costs that exceed, in any one instance, $250,000. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prepare more prudently for future storms.

X. CONSERVATION INCENTIVE PROGRAM ("CIP")

Q. How and when was the CIP approved?

A. PSE&G filed for approval of its Clean Energy Future – Energy Efficiency Program ("CEF-EE Program") on October 11, 2018 ("CEF-EE Petition"). Subsequent to the CEF-EE Petition, on June 10, 2020, the Board approved a framework ("Framework Order")[20] for the performance targets; program administration; cost recovery (including lost revenue treatment); evaluation, measurement, and verification ("EM&V"); and filing and reporting standards for implementation of New Jersey's EE and peak demand reduction ("PDR") programs. The Framework Order allowed utilities the option of seeking a lost revenue adjustment mechanism ("LRAM") or the Conservation Incentive Program to address lost revenue recovery as provided for in the Clean Energy Act ("CEA"). On September 23, 2020, the Board approved a stipulation resolving all matters associated with the CEF-EE Petition, which included approval of the CIP mechanism.

Q. What is the purpose of the CIP and how does it work?

A. The CIP mechanism provides for rate adjustments related to changes in the average use per customer when compared to a baseline, removing the Company's disincentive to encourage customers to conserve energy that exists under traditional ratemaking. The CIP applies to both the Company's electric ("ECIP") and gas ("GCIP") businesses. The ECIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline revenue per customer ("BRC") from the actual revenue per customer and multiplying the resulting revenue per

[20] *I/M/O the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs*, B.P.U. Docket No. QO19010040 et al., Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs (June 10, 2020) ("Framework Order").

customer by the actual number of customers for the month. The GCIP margin deficiency to be collected from customers or the margin excess to be refunded to customers is calculated each month by applicable rate schedule by subtracting the baseline use per customer ("BUC") from the actual use per customer and multiplying the resulting use per customer by the actual number of customers and per therm margin rate for the month.

Q. Are you proposing any adjustments to the CIP in this proceeding?

A. Yes, there are two adjustments that must be made in a base rate case proceeding associated with the CIP. First, a base rate case proceeding will establish new baseline use (gas) or revenue (electric) per customer figures that will go into effect upon approval of this proceeding. Second, a *pro forma* adjustment must be made to the test year income statement to remove the CIP accrual to account for the reset of the CIP baseline.

Q. Please explain the resetting of the BUC and BRC.

A. Aspects of the CIP tariff that interrelate with PSE&G's base rate revenue recoveries must be updated when new base rates are determined in a base rate case. The CIP is designed to adjust for changes in the average use per customer compared to the amount approved to set base rates, and thus the baseline for the CIP must be aligned with the approved billing determinants used to set base rates in this proceeding. In addition to the updated BUC and BRC, the date for determining incremental large customers should be set at June 1, 2024, the first day following the end of the test year. An adjustment to the number of customers is allowed under Rate Schedule Large Volume Gas ("LVG") to account for new customers with significant loads. The calculation of the LVG customer adjustment is the aggregate connected load for all new active customers that exceed 1,200 cubic feet per hour ("CFH") divided by 600 CFH.

Please see Schedule MPM-55E and MPM-55G for the updated BRC and BUC based on the actual results from June 1, 2023 – October 31, 2023 and a forecast from November 1, 2023 – May 31, 2024. The revised baselines will be updated with actual results when available.

Q. Why does the Company need a *pro forma* adjustment for the test year CIP accrual?

A. The CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC. The details associated with the elimination of the test year CIP accrual are reflected in Schedule MPM-50.

XI. EMBEDDED COST OF DEBT RATE RECOVERY

Q. How does the Company recover interest expense in base rates?

A. Interest expense is recovered as the Company's electric and gas rate base multiplied by the long-term debt component of its capital structure and then by the embedded cost of long-term debt. Each of these components will be approved by the Board in this proceeding based on results as of the end of the test year and approved post-test year adjustments.

Q. Can there be significant movements in interest rates?

A. Yes. This is highlighted by recent sharp movements in interest rates attributed to federal reserve policy seeking to lower inflation and other market factors. At the beginning of 2022, the 10-year treasury was approximately 2% and in less than two years, the 10-year treasury has

recently been near 5%. Further, the outlook for interest rates is expected to be higher for some time – and certainly during the initial period when rates set in this case will go into effect -- due to a variety of market factors. As of May 31, 2024, PSE&G's embedded cost of long-term debt is estimated to be 4.02% based on expected additional financings in the test year. Quite simply, in the current and expected interest environment, any new financing given the level of treasury rates would be expected to significantly exceed the embedded cost of long-term debt.

Q. Has the impact of interest expense increased since the last rate case and do you expect it to continue to grow?

A. Yes. While the path of future interest rates is difficult to predict, the materiality of interest expense will continue to increase as debt grows to finance PSE&G's capital investment program needed to meet the State's clean energy targets and maintain safe and reliable service. PSE&G's long-term debt outstanding has grown significantly since the last rate case (debt outstanding was approximately $9 billion at the end of 2018 and is approximately $14 billion as of October 31, 2023). PSE&G supports the State's transition to a cleaner environment, but that transition will require significant capital investment to the distribution system that will be financed by the Company's approved capital structure, significantly increasing PSE&G's long-term debt balance and overall interest expense. In addition to financing new capital investments, approximately $1.1 billion of the existing long-term debt will come due in 2024 and 2025.

Q. What are the implications of interest rate increases on the rate setting process?

A. Upon setting new rates, PSE&G would not be expected to recover the cost of debt for a period of time that is difficult to predict. The rate setting process should provide the Company an opportunity to earn its allowed return in at least the first-year new base rates go

into effect, which is why post-test year pro forma adjustments have been approved by the Board for known and measurable expenses. The current interest rate environment and the need to refinance existing debt after the end of the test year will likely result in the Company's interest expense exceeding its revenue recovery within the first year that new rates go into effect. This treatment could also enable the Company to stay out of rate cases longer than it otherwise would, thereby deferring impacts to customers.

Q. What is the Company's proposal to address changes in interest expense after the test year?

A. The Company proposes a new interest cost reconciliation mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding. Please see Schedule MPM-55 for the proposed calculation of the deferral. The interest cost reconciliation mechanism avoids the need for a *pro forma* adjustment that would increase costs to customers in this proceeding and will provide the Company an opportunity to earn its allowed return. The mechanism also ensures the Company recovers no more or less than its allowed interest expense and can be reevaluated in a future base rate case.

Q. Will the proposed mechanism allow the Company to defer the incremental interest expense on increases in its outstanding long-term debt balance outside of a rate case?

A. No, it will not. Increases in the Company's rate base and associated long-term debt balance will continue to be recovered through the base rate case process and will not be part of the deferral mechanism. The deferral accounts only for changes in the Company's embedded cost of debt. The rate base balance and long-term debt percentage in the mechanism will be the amounts approved by the Board in this proceeding. As a result, the Company will

still bear the risk of increases in interest expense associated with investments that have not been approved by the Board.

Q. Would this mechanism be symmetrical and allow for potential refunds to customers?

A. Yes. As the market has shown over the past few years, interest rates can rapidly change downwards (such as during the COVID-19 pandemic) or upwards (such as during periods of inflation and other market crises). If interest rates decline again in the future and reduce the Company's embedded cost of debt, those amounts would similarly be deferred for future refund to customers. Rate movements will be influenced by the prevailing economic environment, which could vary from a re-acceleration of inflation to a hard landing of the U.S. economy. Rate movements could also be driven by a shock to the system such as a pandemic, banking crisis, or global conflict. Fluctuations in interest rates can be higher or lower, and the proposed accounting treatment will ensure variances are shared between the Company and customers.

Q. Does this proposal shelter customers from the execution risk of financing plans to customers?

A. Yes. A long-term bond is priced using a treasury rate and a credit spread. For reference, in August 2023, PSE&G issued 10-year debt with a coupon of 5.20%, reflecting a 10-year treasury as the reference rate plus a credit spread of 103 basis points. Generally, the cost of debt is driven by the treasury component, which is determined by the macroeconomic environment. The credit spread is driven by market volatility, highlighting the need for strong investment grade credit ratings to maintain access to the markets on reasonable terms. Despite the interest rate environment, PSE&G utilizes its credit rating and the strong capabilities of its bank group to run a competitive book building process to obtain the lowest-possible price.

Further, the deferral mechanism will apply only to the approved long-term debt balance in this proceeding and therefore the Company—and not customers—bears the risk on its increased interest expense as its outstanding long-term debt balance increases between rate cases.

Q. Are you proposing any other adjustments associated with the embedded cost of long-term debt?

A. Yes. For the Company's future infrastructure investment program ("IIP") rate adjustment filings, such as GSMP II Extension, IAP and the proposed future CEF-EV rate adjustments, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding. Every IIP rate adjustment filing includes an initial forecast that is trued-up with actual results before new rates are implemented, and the actual embedded cost of long-term debt can be updated at that time. In addition, the WACC in the Company's Green Program Recovery Charge ("GPRC") and TAC should be updated monthly, consistent with the monthly return calculation for each program with a return component. For the GPRC, the size of the programs (such as for the Clean Energy Future – Energy Efficiency II filing) have significantly increased, causing a more significant impact on the debt costs to finance that investment. With regard to the TAC, the Company has voluntarily proposed to flow-back tax benefits to customers on an accelerated basis, reducing customer bills in this proceeding, but lowering the Company's cash flow, which impacts the need and timing for additional financing. As a result, it is appropriate to use the actual long-term debt rate in the calculation of the Company's return in those proceedings.

XII. INCENTIVE COMPENSATION

Q. Please briefly describe the Company's compensation philosophy.

A. PSE&G maintains a compensation structure designed to attract and retain a talented and diverse workforce to operate safely, reliably, and cost-effectively. The Company's compensation structure (salary ranges, incentive compensation targets, and related factors) is regularly benchmarked to enable the Company to attract and retain its management team and overall workforce.

Q. Does the Company base part of employee compensation on the achievement of various incentives?

A. Yes. Similar to industry peers and the vast majority of companies, PSE&G has a compensation program that is a mix of fixed base pay and incentive pay. The incentive pay is dependent upon achieving established goals. For PSE&G these goals are primarily operational and customer focused. The incentive pay program is designed to encourage employees to focus on the goals that have enabled PSE&G to achieve the levels of reliability, safety, and operational excellence that I have described previously. Included in test year expenses are approximately $36 million ($19 million for electric and $17 million for gas) associated with incentive compensation for PSE&G as well as the Service Company allocation to PSE&G to support the utility. Of that amount, approximately $11 million ($6 million electric and $5 million gas) is provided to officers and relates to a mix of targets, including operational performance, but mostly weighted towards financial results. Of the remaining $25 million, $16 million ($8 million each for electric and gas) relates to achieving operational metrics and strategic goals, with the remainder related to achieving financial goals, all of which ultimately benefit customers as discussed more fully below.

Q. Please explain why the Board should approve the recovery of PSE&G's incentive compensation at this time.

A. As a preliminary matter, it should be recognized that an incentive compensation program is not a "bonus" program as that term is commonly understood. As discussed more fully below, it is the combination of fixed compensation and variable compensation that permits the Company to provide a level of overall compensation necessary to attract and retain qualified personnel. In addition, while there are certain metrics that might be characterized as "financial," these metrics actually benefit both shareholders and customers. For example, containing O&M costs benefits shareholders in the year(s) costs are contained, but also helps keep down test year costs that are ultimately recovered from customers through rate cases, thereby lowering customer rates from what they otherwise would be. That is an incontestable benefit to customers, and it is the product of properly incented employees and a properly incented management team. Also, meeting earnings targets enables investors to have confidence in the Company, which helps to keep the cost of capital down. Finally, including financial goals in an at-risk compensation program ensures that employees are properly encouraged to attempt to achieve operational goals in a cost-effective manner. So, fundamentally, there is benefit for all parties – including, demonstrably, PSE&G's customers -- when financial targets are achieved. Nevertheless, as the Company demonstrates below, the majority of PSE&G's variable compensation metrics relate to operational metrics that directly benefit customers and the achievement of which produces tangible, positive effects on the service provided by the Company.

Q. How does the Company's incentive compensation structure correlate variable compensation to operational performance?

A. The annual variable compensation structure is designed so that the majority of the targets relate to operational metrics. Those metrics are focused on Reliability (e.g., SAIDI and other metrics), customer satisfaction (J.D. Power scores and other metrics), and other operational metrics. The metrics have two components that are scored – Part A, which is to compare the Company to peers, generally with a target of top quartile performance, and Part B, which measures whether the Company did better than the prior year, driven by PSE&G's focus on Continuous Improvement. As a result, the incentives are clearly aligned with the needs of customers as the metrics are directly focused on providing strong service.

Q. You stated that PSE&G's incentive compensation program employs metrics that directly benefit the Company's customers. Please explain that statement.

A. The "scorecard" that the Company employs to determine incentive compensation contains metrics that directly benefit customers. PSE&G tracks many operational and customer service metrics and approximately 12 of them are directly included in the variable compensation calculation. These include important operational and customer-facing metrics such as SAIDI, gas leaks per mile, damages per locate requests, JD Power Customer Satisfaction surveys of both electric and gas customers, and other measures.

Clearly, therefore, PSE&G's employees are provided incentive compensation if they achieve operational targets that benefit customers. As a result, the Company's incentive compensation program should be fully recoverable because it delivers clear and tangible benefits to our customers.

Q. Is the incentive compensation program an essential component of overall compensation?

A. Yes. Not only are these programs among the most important tools that management uses to attract and retain talent, align interests, incent performance, and ensure the delivery of high-quality service to customers, but the variable compensation structure has also delivered tangible benefits to customers, as described above. The Company's compensation philosophy is to target total compensation at the median of companies it competes with for talent. Without the incentive compensation program, which is a common component of compensation among PSE&G's peers, the Company would need to increase the fixed base salary cost to attract and retain the caliber of talent needed to achieve its goals. Taking that approach would result in a similar overall level of compensation and a similar overall level of prudent labor expense, even if key metric(s) were not achieved in a given year. Using incentive compensation is a more effective means to motivate employees to achieve targeted results.

Q. Does the Company's workforce expect that incentive compensation will be part of the overall package of compensation and benefits?

A. Yes. Today's workforce fully expects that a portion of their compensation will be tied to the attainment of stated performance objectives. To attract and retain top talent, the Company must continue to offer a compensation structure that is, in part, incentive based.

Q. Are there negative consequences associated with the disallowance of some or all of the Company's incentive compensation costs?

A. Yes. Obviously, to the extent a portion of these costs are disallowed, the Company would not be able to recover its cost of service. But there are larger ramifications. PSE&G's overall compensation program, including incentive compensation, seeks to set salaries around the mean of companies with whom it competes for our talented workforce. To the extent these

costs were not incurred, the Company would no longer be aligned with industry and regional compensation benchmarks and would therefore expect incremental turnover, inability to attract quality employees, and a deterioration of service over time. The Company's incentive compensation is a prudent cost and PSE&G requests full recovery of its $36 million of incentive compensation expense.

XIII. DEFERRAL REQUESTS – CREDIT AND DEBIT CARD FEES AND IMPLEMENTATION COSTS FOR TIME OF USE RATES

Q. Is the Company proposing an adjustment to reflect a requested change to the treatment of credit card fees?

A. Yes. As demographics change and the percentage of customers using the digital platforms for paying their bills increases, the need to eliminate the charge for credit and debit cards becomes more important. Since 2010, the percent of payments received via check has dropped from over 52% to 17% and continues to decline each year. Currently, while other payment transaction fees are considered normal business expenses and allowed recovery, the credit card and debit card processing fees are not allowed to be recovered through rates, and each is charged as a pass-through fee to customers at the time of payment. This is the number one reason for dissatisfaction as reported by customers when asked about the billing and payments process for PSE&G.

Customers expect seamless electronic payment options. PSE&G provides the ability to pay via its website, mobile app, phone, and text. The Company has expanded customers' ability to communicate and transact business through digital channels and the Board has recognized and encouraged this additional digital access. For payments, these channels lend themselves to payments via credit and debit cards. As the utility industry and technology continues to modernize, payment methods need to as well.

Q. Is there a disparity in the manner the Company treats credit and debit card payments versus other forms of payments?

A. Yes. Within the existing bill and payment options available to customers, there is already a disparity in the unit cost of those transactions, yet credit and debit card fees are the only transaction costs singled out for non-recovery. In-person payments at Customer Service Centers are much more expensive than a mailed check, and sending a paper bill via mail is more expensive than receiving an email, yet PSE&G does not charge individually for these options. The different options are available to all customers who then choose the method that best works for them. The Company proposes treating credit card processing fees as it does the other payment and delivery fees within the billing process, thereby leveling the playing field – among the various payment options.

Q. What is the Company's proposal for credit card transaction fees?

A. The Company proposes to assume the cost for credit card transactions rather than requiring the payment from individuals using a credit or debit card. By assuming the payment, the Company anticipates the cost per transaction will be reduced from the current rate of $3.50 per payment to $2.60. However, this will result in a prudent cost to the utility (just as the cost to process all other forms of payment is prudent) that is not captured in the test year and would not represent the Company's go-forward expenses. Since it is unknown at this time how many customers will pay via credit card once the transaction fee is removed, the Company is proposing to defer those incremental expenses until the next base rate case as participation ramps up. After the conclusion of the next base rate case, the Company will stop the deferral mechanism and the costs would be recovered in the same manner as all other bill processing costs.

Q. Is there another significant cost the Company will occur outside this test year that requires deferral authority?

A. Yes. As discussed in the Direct Testimonies of Mr. Stephen Swetz and Company witness Ahmad Faruqui, the Company is proposing a Pilot Residential and Commercial Time of Use Rate. The TOU rates will utilize AMI to design a rate structure that will encourage customers to shift their usage to off-peak periods, lowering their bills and peak demand on the electric system, which will avoid the need for additional utility infrastructure and generation costs. This is particularly important with the growth in electric vehicles, which can have a significant impact on customer usage and peak demand. To encourage participation, the Company is also proposing a one-year pilot that will refund customers if TOU rates are higher than they would have been charged under RS Rates. However, implementing TOU rates and the ability to compare those rates to the RS rates and issue a refund will require significant changes to the existing billing system, resulting in significant incremental capital and O&M costs that will be incurred after approval of this proceeding.

Q. What is the Company's proposal for the expenditures necessary to implement TOU rates?

A. The Company proposes that the Board provide the Company approval to defer these costs and place them in a regulatory asset as separate and identifiable accounts for recovery of costs deemed prudent in the Company's next base rate case, in the same manner as costs related to the implementation of AMI in the CEF-EC Program. The regulatory asset will include capital costs inclusive of return on the average monthly rate base recorded at PSE&G's pre-tax overall WACC in effect at the time of the deferral. Incremental TOU-related O&M costs will be deferred separately without a return, for recovery in the Company's next base rate case.

The prudency of the TOU Pilot's costs, including those deferred and placed in the regulatory asset, will be reserved for review and determination in the Company's next base rate case.

XIV. TEST YEAR AND REVENUE REQUIREMENTS – ADJUSTMENTS TO BASE ELECTRIC AND GAS DISTRIBUTION RATES

Q. Please describe the test year that is being utilized in this proceeding.

A. The test year in this proceeding is the twelve-month period beginning June 1, 2023 and ending May 31, 2024. The filing consists of five months of actual data (through October 31, 2023) and seven months of estimated data. Actual data is supported by the Company's accounting records, while projected data is based on the Company's financial and capital budget for the period ending May 31, 2024. The Company will update for twelve months of actual data through May 31, 2024 in July 2024, which is consistent with the Company's anticipated rate effective date of September 1, 2024, and ensures the Board and the parties will be able to review twelve months of actual data sufficiently in advance of the estimated rate effective date.

Q. Please discuss the schedules that you are providing to support the revenue requirement.

A. The determination of revenue requirements is premised on the June 2023 through May 2024 test year described above with appropriate *pro forma* adjustments. *Pro forma* adjustments to the test year have been proposed to reflect the expense level of certain items for the twelve months ending August 30, 2025 (the "rate year"), which is the first full year that rates are proposed are anticipated to be effective on September 1, 2024. The costs to be recovered include expenses of running the business (including O&M expenses and taxes) as well as return of and on the capital invested that is necessary to run the business (*i.e.*, depreciation and amortizations, interest expense, and a fair return on equity invested). Plant

additions that are expected to be in service within six months beyond the end of the test year (through November 30, 2024) have been included in rate base.

Set forth below is a description of the schedules identified in the introduction section of my testimony. The schedules reflect information for both electric distribution and gas distribution.

Determination of Revenue Requirements—Schedule MPM-02

Q. Are you presenting a schedule that shows the revenue requirement in this case?

A. Yes. Schedule MPM-02 shows the determination of the revenue requirement increase being requested in this proceeding. Based upon rate bases of $9.3 billion and $8.6 billion for electric distribution and gas distribution, respectively, *pro forma* operating income of $326.8 million and $349.6 million for electric and gas, respectively, and a required rate of return of 7.55%, the increase in required revenue requested is $522.1 million for electric distribution and $422.8 million for gas distribution.

Utility Rate Base—Schedule MPM-03

Q. Please describe the schedule depicting the Company's rate base.

A. Schedule MPM-03 presents projected total electric and gas utility rate bases as of May 31, 2024 and November 30, 2024. Electric rate base is expected to be $9.0 billion by May 31, 2024 and $9.3 billion as of November 30, 2024. Gas rate base is expected to be $8.5 billion by May 31, 2024 and $8.6 billion as of November 30, 2024. The rate bases consist primarily of the utility's investment in distribution plant, net of the accumulated provision for depreciation of utility plant plus distribution working capital, accumulated deferred income taxes, the consolidated tax adjustment, and the exclusion of IAP and GSMP II (as extended) investment that will be recovered in a separate rate adjustment proceeding in accordance with

the orders in those matters. Rate base also includes the regulatory assets associated with the CEF-EC and CEF-EV investments as described below. Rate base represents the investment necessary to provide safe, adequate, proper, and reliable service to customers and is therefore a crucial factor in setting future distribution rates. The components of the Company's distribution rate bases are supported by Schedules MPM-07 through MPM-18 and will be addressed below.

Revenue Factor—Schedule MPM-06

Q. Are you presenting a schedule that depicts the revenue factor for the electric and the gas operation?

A. Yes. The electric revenue factor utilized by the Company in this proceeding is projected to be 1.3947. The factor includes the 9% State of New Jersey Corporate Business Tax, the 21% Federal income tax, and the assessments for the Board of 0.213045% and the Division of Rate Counsel (Rate Counsel) of 0.050234%. The gas revenue factor is the same rate assuming approval by the BPU of transitioning the gas bad debt from base rates to a new component of the gas SBC. If the recovery of gas bad debt expense through the SBC is not approved, the gas revenue factor should include the uncollectible rate at 1.80% (resulting in a revenue factor of 1.4203). This is the forecasted uncollectible expense as the historic rate has been skewed by the COVID-19 deferral and the significant increase in the reserve as a result of the moratorium on shutoffs.

Utility Plant in Service—Schedule MPM-07

Q. Please describe the schedule showing utility plant in service.

A. The electric utility and gas utility plant in service, as shown on Schedule MPM-07, is estimated to be $12.7 billion and $12.3 billion respectively on May 31, 2024 and $13.1 billion and $12.9 billion respectively on November 30, 2024.

Plant-In-Service Additions from May 31, 2023 through November 30, 2024—Schedule MPM-08

Q. Are you also presenting a schedule that shows additions to plant in service?

A. Yes. Schedule MPM-08 provides the direct additions to plant in-service from the actual June 1, 2023 balance projected through November 30, 2024. Additions are expected to total approximately $1.7 billion for electric and $1.7 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule MPM-09

Q. Please describe the schedule that presents Accumulated Depreciation.

A. Electric and gas plant in service have estimated useful lives, which normally extend over many operating periods. The systematic recovery of these investments is accomplished by the recognition in rates of annual depreciation charges, with the accumulated depreciation used to reduce rate base utility plant investments. This has been, and continues to be, an acceptable way of developing rate base because the accumulated depreciation balance recognizes that these amounts have already been charged to customers.

The accumulated depreciation balance reflects the recognition of annual depreciation charges projected through November 30, 2024 based upon the current BPU-approved electric

and gas distribution depreciation rates. Please note that PSE&G is also presenting a study performed by Mr. John Spanos of Gannett Fleming that proposes changes to the existing depreciation rates. The Company has included the annualization of the depreciation expense, described in more detail in schedule MPM-41, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule MPM-10

Q. Is distribution rate base reduced to reflect advances by customers for construction?

A. Yes, it is. Because the costs of construction related to advances made by the Company's electric and gas utility customers are capitalized and included in the distribution rate bases, it is appropriate to reduce distribution plant costs for these advances. As shown on Schedule MPM-10, electric and gas distribution rate base has been reduced by $63.7 million and $24.9 million, respectively, based upon a 13-month average of the most current available actual advances—the period October 2022 through October 2023.

Working Capital

Q. What is "Working Capital?"

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The Company's proposed working capital allowance is $1.2 billion for electric rate base and $672.8 million for gas rate base. Each rate base working capital requirement consists of three components: cash (Lead/Lag), materials and supplies, and prepayments.

Cash (Lead/Lag) Working Capital

Q. Are the amounts shown for Working Capital supported by any analyses?

A. Yes, they are. The cash (Lead/Lag) working capital allowances reflected on Schedule MPM-03 of $925.7 million and $605.3 million that I have included in the electric and gas rate bases, respectively, are the result of detailed Lead/Lag studies supported by Mr. Michael Adams, in separate testimony and supporting schedules.

Materials and Supplies—Schedule MPM-11

Q. How are Materials and Supplies reflected in the filing?

A. I have included $227.2 million and $67.4 million of materials and supplies necessary for ongoing utility electric and gas operations, respectively, in rate base. This is a representative balance of general store items held in inventory for operating and maintenance and capital purposes. It is derived by taking a 13-month average of the most current available actual balances—the period October 2022 through October 2023.

Prepayments—Schedule MPM-12

Q. Does the Company's filing reflect an allowance for prepayments of costs?

A. Yes, it does. The Company is required to make advance payments for the BPU and Rate Counsel assessments, prior to their being charged to operating expenses. Such prepayments occur every year and therefore require a permanent, ongoing investment by the Company to fund them. Accordingly, I have included the average electric and gas utility prepayment requirements of $0.5 million and $0.1 million, respectively, in rate base. These levels are based upon a 13-month average as of October 2023.

Accumulated Deferred Taxes—Schedule MPM-13

Q. Have you incorporated Accumulated Deferred Income Taxes into your rate base calculation?

A. Yes. Company witness Mr. Pardo discusses Accumulated Deferred Taxes in his testimony. I have incorporated Mr. Pardo's Accumulated Deferred Tax Balance shown on Schedule CP-3. The net accumulated deferred taxes amount to a $1.8 billion reduction to electric rate base and a $1.8 billion reduction to gas rate base. These amounts are based upon the plant in service balances reflected in the respective rate bases as of November 30, 2024. For more details, please see the testimony of Mr. Pardo.

Consolidated Tax Adjustment—Schedule MPM-14

Q. Does the Company's filing recognize the Board's most recent policy concerning Consolidated Tax Adjustment ("CTA")?

A. Yes, it does. The Company believes that, as others representing PSE&G have testified in the past, the imposition of a CTA is a flawed and inappropriate regulatory adjustment. Nevertheless, Company witness Mr. Pardo has calculated a CTA and discusses the basis for that adjustment in his testimony. I have incorporated Mr. Pardo's CTA adjustment as shown on Confidential Schedule CP 5. This adjustment decreases electric distribution rate base by $3.4 million and results in no change to gas distribution rate base due to a cumulative tax loss. For details on the calculation of the Consolidated Tax Adjustment, please see the testimony of Mr. Pardo.

IAP Rate Base Adjustment-Schedule MPM-15

Q. Why is there an IAP Adjustment?

A. The IAP program was approved for recovery of investments through a separate mechanism outside of a base rate case. Because the Company has IAP investments that will occur during the test year but will be recovered through an IAP rate adjustment proceeding outside of the test year in accordance with the IAP Order, the IAP investments must be excluded from rate base to avoid double recovering the investment.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the IAP that will be recovered in a separate IAP rate adjustment proceeding, which is expected to be investment placed in service from February 1, 2024 through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric and gas rate base has been reduced by $27.9 million and $29.3 million, respectively, as of November 30, 2024.

CEF-EC Rate Base Adjustment-Schedule MPM-16

Q. What is the CEF-EC rate base adjustment?

A. The CEF-EC rate base adjustment accounts for the CEF-EC regulatory asset on CEF-EC related plant in-service that is or will be placed into service within six months of the end of the test year. Paragraph 22 of the CEF-EC stipulation approved by the Board states: "the Company will book a regulatory asset ("CEF-EC Regulatory Asset") comprised of: 1) its CEF-EC capital investment ("CEF-EC Investment Deferral"), and 2) the associated stranded costs

("Stranded Cost Deferral") on legacy meters in accordance with paragraphs 23 and 24 below."[21]

Q. How is the CEF-EC Regulatory Asset calculated?

A. Per paragraph 23 of the CEF-EC stipulation approved by the Board, the CEF-EC Investment Deferral is calculated as:

> *CEF-EC Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[22]

Paragraph 13 of the Stipulation authorized the two phases of AMI deployment, which incorporate a geographic strategic approach designed to maximize installation efficiency and customer satisfaction.[23] To minimize the inefficiencies of dispersed meter deployment, these phases have proceeded geographically regardless of the age of any particular legacy meter at the time of its removal. Paragraph 24 of the CEF-EC stipulation stated the Stranded Cost Deferral will be calculated as:

> *Stranded Cost Deferral = Accelerated Depreciation Expense associated with Legacy Meters – Depreciation Expense on Legacy Meters at the Approved Depreciation Rate as Determined in the 2018 Base Rate Case*[24]

Further, paragraph 28 of the CEF-EC Stipulation states,

> The CEF-EC Program investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance as described in paragraph 23 above. For ratemaking purposes, depreciation expense will not begin on CEF-EC Program investment until reflected in base rates in the Next Base Rate Case. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EC Program investment regulatory asset.[25]

[21] CEF-EC Order at Stipulation ¶ 22.
[22] *Id.* ¶ 23.
[23] *Id.* ¶ 13.
[24] *Id.* ¶ 24.
[25] *Id.* ¶ 28.

Q. Did the CEF-EC Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 21 of the CEF-EC Stipulation states:

> The Parties also agree that reasonable and prudent costs associated with the CEF-EC Program investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the *Board's Elizabethtown* Water.[26]

Q. Does the CEF-EC Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 26 of the Stipulation approved by the Board states "The Parties agree that the revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EC Regulatory Asset defined in paragraphs 22-24 above to the extent that is deemed prudent."[27] The recovery "of" the CEF-EC Regulatory asset is described below in Schedule MPM-47. This adjustment to rate base is to account for the return "on" the CEF-EC Regulatory Asset derived from the CEF-EC investment in the same manner as Allowance for Funds Used During Construction ("AFUDC") is added to rate base when a project is placed into service.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $230.0 million as of November 30, 2024.

CEF-EV Rate Base Adjustment-Schedule MPM-17

Q. What is the CEF-EV Adjustment?

A. The CEF-EV rate base adjustment accounts for the CEF-EV regulatory asset on CEF-EV related plant in-service that is or will be placed into service within six months of the end of the test year. As stated in paragraph 22 of the CEF-EV Stipulation approved by the Board:

[26] *Id.* ¶ 21 (internal footnote omitted).
[27] *Id.* ¶ 26.

The Company will invest in EV infrastructure as described in paragraph 15 above. Until being rolled into base rates, as described further below, those CEF-EV related capital costs shall be deferred and placed in a regulatory asset, for recovery in the Company's next base rate case, to be filed no later than January 1, 2024 (the "Next Base Rate Case").[28]

Q. How is the CEF-EV Regulatory Asset calculated?

A. Per paragraph 26 of the CEF-EV stipulation approved by the Board, the CEF-EV Investment Deferral is calculated as:

*CEF-EV Monthly Investment Deferral = (((Pre-Tax Cost of Capital /12) * Average Monthly Rate Base) + Monthly Depreciation and/or Amortization Expense) + (Average Monthly Investment Deferral Balance * (WACC /12))*[29]

Further, paragraph 30 of the CEF-EV Stipulation states,

The CEF-EV investment that is placed into service, but not yet reflected in customer base rates, will record a monthly accrual of a deferred return that will be capitalized and included in the plant balance. For ratemaking purposes, depreciation expense will not begin on CEF-EV investment until reflected in base rates in the Next Base Rate Case or any subsequent base rate case or rate case reopener. Since depreciation expense must be booked when the investment is placed in service for tax and financial reporting purposes, the Company will defer the depreciation in the CEF-EV investment regulatory asset.[30]

Q. Did the CEF-EV Order allow for investment beyond the end of the test year?

A. Yes. Paragraph 23 of the CEF-EV Stipulation states:

The reasonable and prudent costs associated with the CEF-EV investment that are likely to be in-service by the end of six (6) months after the end of the test year in the Company's Next Base Rate Case shall be reflected in the rates established in that case, consistent with the Board's *Elizabethtown Water* standards.[31]

Q. Does the CEF-EV Order discuss the recovery of the regulatory asset?

A. Yes. Paragraph 28 of the Stipulation approved by the Board states

The revenue requirement in the Next Base Rate Case or a subsequent base rate case, if applicable, will include a return of and on the CEF-EV Regulatory Asset defined in paragraph 25 above. The return on the deferred investment will be based on the

[28] CEF-EV Order at Stipulation ¶ 22.
[29] *Id.* ¶ 26.
[30] *Id.* ¶ 30.
[31] *Id.* ¶ 23 (internal footnote omitted).

approved WACC in the Next Base Rate Case, or subsequent base rate case, adjusted for income taxes and BPU and Rate Counsel assessment fees. The return of the deferred investment will be based on the Board approved depreciation/amortization rates determined in the Next Base Rate Case or any other appropriate period approved by the Board.[32]

Q. What is the impact of this adjustment?

A. As a result of this adjustment, electric rate base has been increased by $43.2 million as of November 30, 2024.

Q. Does the CEF-EV Order discuss recovery for investment beyond the end of the six-month post-test-year period?

A. Yes. The CEF-EV Order allows for annual rate adjustment filings to recover investments placed into service more than six months after the end of the test year. The Company's proposal for the methodology and schedule of those annual rate adjustment filings is set forth in the testimony of Mr. Swetz.

GSMP II Extension Rate Base Adjustment-Schedule MPM-18

Q. Why is there a GSMP II Extension Adjustment?

A. The GSMP II Extension was approved for recovery of investments through a separate mechanism outside of a base rate case.[33] Because the Company has GSMP II Extension investments that will occur during the test year but will be recovered through a GSMP II Extension rate adjustment proceeding outside of the test year in accordance with the GSMP II Extension Order, the GSMP II Extension investments must be excluded from rate base to avoid double recovering the investment.

[32] *Id.* ¶ 28.
[33] *See* GSMP II Extension Order.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation, and accumulated deferred income taxes associated with the GSMP II Extension that will be recovered in a separate GSMP II Extension rate adjustment proceeding, which is expected to be investment placed in service through November 30, 2024.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, gas rate base has been reduced by $256.1 million as of November 30, 2024.

Electric and Gas Distribution Operating Income

Q. Please describe the schedules for Electric and Gas Operating Income.

A. Schedules MPM-19 through MPM-28 present a complete picture of PSE&G's electric and gas distribution operations. These schedules contain sales, distribution operating revenues, and number of billed customers by class of business for the electric and gas distribution businesses of the Company. Also included are O&M expenses by primary function, depreciation and amortization, taxes other than income taxes, and current and deferred income taxes. Schedule MPM-19 presents the income statements for these business segments. This information has been provided for the twelve-months ending May 31, 2024, which is the test year based on five months of actual data and seven months of forecast.

Pro-forma Distribution Operating Income—Schedule MPM-29

Q. Are you proposing to adjust Test Year Operating Income?

A. Yes. Schedule MPM-29 is a summary of *pro forma* adjustments to the test year electric and gas utility operating income. These *pro forma* adjustments adjust test period operating

income for known or measurable changes to expense and income levels so as to reflect the expected expense and income levels for the rate year, which is the first twelve months after new rates are set as a result of this proceeding. Adoption of these adjustments by the Board will provide the Company with a realistic opportunity to earn a reasonable return on its electric and gas investment when the rates are in effect.

The Company's revenue requirements determination includes 21 adjustments to its test period electric distribution operating income. The *pro forma* adjustments reduce the test period electric operating income by $142.2 million after-tax. On the gas distribution side there are 19 adjustments that reduce the test period operating income by $110.3 million. There are 24 *pro forma* adjustments in total (16 combined electric and gas adjustments, 5 electric only and 3 gas only). Each of the *pro forma* adjustments will be discussed in more detail below.

Adjustment No. 1: Wages—Schedule MPM-30

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of $7.4 million and $6.7 million for electric and gas, respectively, represent the adjustment to the test year to reflect wage increases applicable to the rate year. These increases are to the labor costs applicable to Bargaining Unit employees; Management, Administrative, Secretarial, and Technical ("MAST") employees; and Service Company employees charged to PSE&G. The increases are based on labor charges to electric distribution and gas distribution during the test year.

The Company recently negotiated Bargaining Union increases for the twelve-month period ending May 31, 2024 as well as the Rate Year ending August 31, 2025. These contracts contain agreed-upon annual wage increases of 3.0% each year. The wage increases are effective on May 1, 2024 and May 1, 2025. For MAST employees, average wage increases of 3.5% were

implemented in March of 2023. While no final decisions have been reached as to future years, best current projections based on benchmarking survey data are a 4% increase effective in March 2024 and a 4% increase in March of 2025.

The Board should continue its consistent practice of recognizing the importance of test year labor adjustments. The Company's employees are a critical element in meeting the service and reliability needs of our customers, and this adjustment to the test year ensures the Company's rates will reasonably reflect the cost of this workforce when rates are in effect.

Adjustment No. 2: Payroll Taxes—Schedule MPM-31

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.5 million and $0.5 million for electric and gas, respectively, result from the increase to operating expense associated with payroll taxes consistent with the wage adjustments made above. This adjustment reflects increases in the Federal Insurance Contribution Act Tax ("FICA") for increases in taxable wages and taxable wage ceiling levels. Based on the Company's historic average, additional payroll taxes for the wage adjustment in Schedule MPM-30 are calculated utilizing a composite 6.88% tax rate.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—MPM-32

Q. Please describe the Interest Synchronization Adjustment.

A. The Board, in the past, has adopted an adjustment to synchronize the Federal income tax savings associated with interest in the test year with the tax savings based on interest calculated using the weighted cost of debt in the capital structure utilized to support rate base.

As can be seen on Schedule MPM-32, the interest-bearing components of PSE&G's capitalization supporting rate base produce synchronized interest expenses of $3.7 million more than the interest expense in the test year for electric and $4.5 million more than interest expense

in the test year for gas, resulting in tax savings of $1.0 million for electric and tax savings of $1.3 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule MPM-33

Q. Please describe the adjustment for Pension and Fringe Benefits.

A. The adjustments to test year operating income for pension costs and fringe benefits amount to a decrease of $20.9 million for electric and $15.6 million for gas, reflecting the expected change in these costs over the test period amounts. The adjustment encompasses expenses associated with pensions, OPEB, medical, dental, thrift, long-term disability, insurance, and workers compensation for employees providing support services to PSE&G.

As noted earlier, PSE&G has pension income that is increasing operating revenues and decreasing the revenue increase requested in this case, despite PSE&G not having access to the pension income. The pension and OPEB *pro forma* adjustments reflect the expected income for 2024, which will be known and measurable before the end of the test year. While the 2024 pension income is expected to be less than in the test year, pension and OPEB are still projected to be income, reducing the revenue requirement paid by customers.

While the Company has also previously described the numerous steps PSE&G has taken to reduce fringe benefit costs, these costs have continually increased, in particular medical costs. Other fringe benefit costs are escalated based primarily on contract renewals, including those for benefit administration costs, compliance, and consulting work.

The Board should continue to recognize that the Company's employees are critical to meeting the service and reliability needs of our customers. The ability to offer a package of wages and benefits will allow the Company to attract and retain the skilled employees that are needed. The revenue to cover those costs must be provided.

Adjustment No. 5: Electric / Gas Company Owned Life Insurance ("COLI") Interest Expense—Schedule MPM-34

Q. Please describe the adjustment required to reflect Company Owned Life Insurance.

A. In an effort to reduce a portion of the expenses associated with certain employee benefit plans, PSE&G has invested in COLI policies. COLI is a corporate owned investment in cash value life insurance, which provides an income stream to the Company.

A portion of the Company's workforce is covered by policies with the Company as owner and beneficiary. The cash value of the insurance contracts earns a return, which the Company utilizes to offset benefit expenses. The Company, as owner, is permitted to borrow against the policy during its life without interfering with the policy's accumulation of earnings. The policy provides life insurance proceeds upon the death of the insured sufficient to settle any outstanding loans.

The earnings associated with the growth in the policy's cash surrender value have produced a net credit to benefits expense. For the test year, the credit to Administrative and General Expense combined with tax savings is $4.1 million for electric distribution and $1.2 million for gas distribution. Interest expense on funds borrowed from the policies is directly related to the $2.1 million for electric distribution and $0.7 million for gas distribution in benefits attributable to the policies. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $2.1 million for electric and $0.7 million for gas, thereby reducing operating income to properly account for all aspects, both benefits and costs, of the COLI.

Adjustment No. 6: Weather Normalization —Schedule MPM-35

Q. Is an adjustment necessary to reflect the results of Weather Normalization?

A. Yes. This pro-forma adjustment is required to adjust test year actual results to reflect normal weather based on weather patterns over a 20-year period as measured at Newark Liberty International Airport. Because actual weather patterns during the time the rates will be in effect are assumed to be normal, this adjustment to the test year is an appropriate rate setting procedure. The use of unadjusted weather-related actual sales levels would result in overstating or understating the revenue requirement compared to normal. Schedule MPM-35 shows the adjustments necessary to reflect normal weather for the period June 2023 through May 2024. This schedule shows a comparison of the distribution revenue for the actual twelve months with that based upon normal weather. Distribution revenue represents the base rate revenue from the sale of a kWh, kW, or therm, excluding clauses and supply. In order to adjust the actual results to a normal sales level, a decrease to test period revenue of $3.5 million for electric is required since the first five months of the test year, June 2023 to October 2023, was warmer than normal. This is the same weather impact included in the billing determinants data in the testimony of Mr. Swetz. An increase to test period revenue of $4.4 million for gas, is required since the first five months of the test year, June 2023 to October 2023, was warmer than normal.

Adjustment No. 7: Gains/Losses on Sales of Property—Schedule MPM-36

Q. Please describe the adjustment to reflect Gains/Losses on Sales of Property.

A. This adjustment allocates one-half of the gain on sales of property, net of associated income taxes, to customers based on a five-year average. The use of a five-year average provides a representative amount of gains for ratemaking purposes, avoiding the distortion that would occur

if an abnormally high or low level of gains is recognized in the test period. The Company has included the five-year average ending May 2024 as representative and appropriate for this proceeding. The adjustment to operating income for the customers' share of the five-year average gain is an increase of $42,000 for electric and $207,000 for gas.

Adjustment No. 8: Real Estate Taxes—Schedule MPM-37

Q. Is the Company presenting an adjustment for Real Estate Taxes?

A. Yes. This adjustment of $0.6 million decrease for electric and $0.3 million increase for gas adjusts the test year operating expense to be representative of the level of property tax expense that is expected to be accrued in the twelve-month period following the date new base rates go into effect. The increase in property tax expense between the rate year and the test year is consistent with actual experience. Accordingly, electric and gas operating income is reduced by the aforementioned amounts.

Adjustment No. 9: Insurance Premiums—Schedule MPM-38

Q. Please describe the adjustment necessary to reflect the Company's Insurance Expense.

A. There are items for which PSE&G carries outside insurance policies (*i.e.*, Corporate Property, Excess Liability Insurance, and Director's & Officers Insurance) for which it pays premiums of approximately $6.9 million for electric and $4.0 million for gas for the year. This adjustment before taxes of $671,000 for electric and $366,000 for gas increases the test year operating expense by $483,000 and $263,000 and is representative of the level of insurance expense that is expected to be accrued in the rate year. The increase in insurance expense between the rate year and the test year reflects input from our insurance carriers and actual experience.

Adjustment No. 10: ASB Margin—Schedule MPM-39

Q. Please describe the ASB margin adjustments that are necessary to reflect the proposed treatment of PSE&G's appliance service business.

A. For the reasons described in Section VI above, the Company is proposing that Gas ASB margins be accounted for as 50% above the line, in the same manner as is done for Electric ASB Margin. After adjusting for tax effect this results in a decrease to operating income of $14.8 million for gas.

Adjustment No. 11: TSG-NF Margin—Schedule MPM-40

Q. Please describe the adjustment for the TSG-NF Margin.

A. A reduction to gas operating income in the amount of $0.7 million is being made. This adjustment is discussed in the testimony of Mr. Swetz.

Adjustment No. 12: Depreciation Annualization and Proposed Rate Change — Schedule MPM-41

Q. Is the Company proposing adjustments related to Depreciation Annualization and to reflect a proposed change in depreciation rates?

A. Yes. This adjustment is to allow for the recovery of the depreciation expense associated with the total investment in Plant in Service in rate base approved in this proceeding. As described above, the Company is requesting rate base as of November 30, 2024. Essentially, the depreciation expense in the test year represents the depreciation expense on the average plant in service in the test year. The actual depreciation expense as a result of this rate case proceeding will be a full year's depreciation expense on the approved plant in service as of November 30, 2024. To arrive at the appropriate depreciation expense for the approved plant in-service, the depreciation expense in the last month used to determine rate base for this

proceeding (November 30, 2024) is annualized by multiplying the balance by twelve. The difference between the annualized depreciation expense and the Test Year depreciation expense produces the pre-tax adjustment. It should be noted that the proposed annualization of depreciation expense is also incorporated in Accumulated Depreciation (Schedule MPM-09) as a rate base deduction using a mid-year convention. Therefore, this adjustment is simply to sync depreciation expense with the approved rate base balance. Accordingly, test year expense is increased $4.0 million for electric and $27.1 million for gas.

In addition, the Company has proposed new electric and gas distribution depreciation rates, including cost of removal, based on an Electric Depreciation Study and a Gas Depreciation Study, supported by the testimony of Mr. Spanos.

The proposed depreciation rates have also been annualized for estimated electric and gas plant balances for the month prior to the rate year. The difference between the annualized rate year expense based on the proposed rates versus the annualized expense based on current rates is an additional pre-tax adjustment, which increases depreciation expenses by $57.9 million for electric and by $72.2 million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $44.5 million for electric and $71.4 million for gas.

Adjustment No. 13: Test Year Amortization Adjustments - Schedule MPM-42

Q. Please describe the adjustment of Test Year Amortizations.

A. This schedule is to adjust operating income for amortizations that are ending during the test year. In the 2018 base rate case, the Signatory Parties agreed to an amortization of $65.605 million over a five-year period addressing all of the deferral recovery requests in that

proceeding.[34] The 2018 base rate case was approved as effective November 1, 2018, so the five year amortization ended on October 31, 2023. This adjustment is to remove the amortization expense from the start of the test year through October 31, 2023 so that the test year operating income does not reflect any of this expense that will not occur going forward. In addition, test year operating income reflects amortization expense on IT capital. However, recovery of IT capital associated with the CEF-EE Program and Community Solar Program are recovered separately through the Green Program Recovery Charge. As a result, the IT amortization for these programs must be excluded from base rate recovery. The adjustment represents an increase in operating income of $17.3 million for electric and $5.9 million for gas.

Adjustment No. 14: Rate Case & Management Audit Expenses– Schedule MPM-43

Q. How does the Company propose to treat rate case expense?

A. This adjustment seeks recovery of all prudently incurred rate case and management audit expenses. As the Company was required to submit this rate case as a result of the GSMP II Order, among other Orders, it is appropriate for the Board to allow for recovery of the expenses required to complete the filing. The Company is seeking to remove all rate case expenses incurred during the test year and recover those expenses as a regulatory asset over a three-year period. In addition, regulated utilities are subject to Management and Affiliate Transaction audits and an audit of PSE&G commenced in 2021. The BPU awarded the audit contract to Overland Consulting for $1.6 million. The Company deferred the $1.6 million cost of the audit paid to Overland and is seeking recovery of the regulatory asset in this proceeding, also over a three-year period. The total adjustment for both rate case expenses and the recovery

[34] 2018 Rate Case Order at Stipulation ¶ 6.

of the management audit costs represents a decrease in operating income of $189,000 for electric and $150,000 for gas.

Adjustment No. 15: ES II / IAP Revenue Adjustment – Schedule MPM-44

Q. Please discuss the adjustment the Company proposes for ES II and IAP rate adjustments during and after the test year.

A. The Company proposes an adjustment to increase test year Operating Income so it reflects the full annual impact of the ES II and IAP rate adjustments rolled into rates during the test year.

Q. Why is this adjustment necessary?

A. When the ES II and IAP rate adjustments occur, base rates will be increased to collect the annual revenue requirement of the rate adjustment. The revenue increase will be added to current rates at the time this proceeding is concluded, which will include the annualized impact of the ES II and IAP adjustments in the test year. The revenue increase from the rate case will be based on the operating income during the test year. For the ES II and IAP rate adjustments that occur during the test year, base rates will be increased for the annual revenue requirement, but only a portion of the revenues from that rate increase will be captured in the test year operating revenue as these rate adjustments become effective. This adjustment is necessary to adjust test year operating revenue to coincide with base rates at the conclusion of the rate case.

Q. What are the ES II and IAP rate adjustments that have occurred and will occur during this proceeding?

A. In accordance with the ES II Order, rates changed November 1, 2023 as a result of the fourth rate adjustment filing (Rate Adjustment #4) based on investments through July 31,

2023.[35] The fifth rate adjustment filing (Rate Adjustment #5), was submitted on November 1, 2023 based on anticipated investment through December 31, 2023 for rates effective May 1, 2024.[36] Rate Adjustment #5 will be updated with actual investment through December 31, 2023 by February 21, 2024.

The first IAP rate adjustment was submitted on November 1, 2023 for rates effective May 1, 2024 based on plant in service through January 31, 2024.[37] The first Rate Adjustment will be updated with actual investment through January 31, 2024 by February 21, 2024.

Q. How was the adjustment calculated?

A. The goal of the adjustment is to ensure that test year Operating Income reflects the current rates in effect before the proposed rates from this proceeding are implemented. For the base rate changes implemented during the test year, this adjustment multiplies the rates for the adjustment by the billing determinants for the test year prior to the implementation date. Using IAP as an example, the adjustment would apply the increase in base rates from the IAP change effective May 1, 2024 to the actual weather normalized billing determinants from June 1, 2023 through April 30, 2024. An adjustment is not needed from May 1, 2024 forward as the revenue will already be included in the test year operating revenue as a result of the IAP rate adjustment.

[35] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23050273, Decision and Order Approving Stipulation (October 25, 2023).
[36] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Energy Strong II Program*, BPU Docket No. ER23110784 (filed November 1, 2023).
[37] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Electric Rate Adjustments Pursuant to the Infrastructure Advancement Program*, BPU Docket No. ER23110783 (filed November 1, 2023).

Q. Is an adjustment required for the rate adjustments prior to the start of the test year?

A. No. For all adjustments prior to the start of the test year, the full annual revenue associated with the adjustments will be reflected in the operating income in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $30.2 million for electric and $0.0 million for Gas.

Adjustment No. 16: BGS Administration Labor Costs to the BGS Charge Reconciliation Charge – Schedule MPM-45

Q. Why is the Company proposing an adjustment to O&M Expense related to labor costs for Basic Generation Service ("BGS") administration?

A. This adjustment is being made to remove labor costs associated with the administration of BGS from the Company's operations and maintenance expense as it will be recovered within the Company's reconciliation charge upon the conclusion of this proceeding.

Q. Why is this adjustment necessary?

A. On July 15, 2020, the BPU issued an Order of Implementation, effective July 25, 2020, requiring Electric Distribution Companies ("EDCs") to file a plan for implementation of the fourteen (14) accepted recommendations from the Final Report filed by Liberty Consulting Group, Inc.[38]. One of the accepted recommendations was to track direct administrative costs that are common across all EDCs and related to the provision of BGS, and recover those costs through their BGS Reconciliation charge(s) following their respective next base rate cases. As

[38] *I/M/O the Request for Proposal for a Financial Audit of the New Jersey Electric Distribution Companies' Basic Generation Administrative Expense and Other Related Expenses*, Docket No. EA17010004, Order of Implementation (July 15, 2020).

this is PSE&G's first base rate case since that Board Order, this adjustment is being made to remove these BGS related administrative expenses from the test year so that they can be recovered through the BGS reconciliation charge.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $220,000 for electric.

Adjustment No. 17: Gas Bad Debt in SBC – Schedule MPM-46

Q. Please discuss the adjustment the Company is proposing for gas bad debt.

A. As discussed in Section VIII above, the Company proposes to move base rate recovery for gas bad debt expenses from base rates to a new Social Programs component of the Gas SBC, the same recovery mechanism utilized for recovery of Electric bad debt expenses. As a result of the proposed adjustment, operating income will increase by $24.8 million for gas. This adjustment will be offset by the proposed gas bad debt SBC component discussed in further detail in the testimony of Mr. Swetz.

Adjustment No. 18: Clean Energy Future-Energy Cloud Amortization – Schedule MPM-47

Q. What is the CEF-EC regulatory asset?

A. As discussed above in Schedule MPM-16, the Company was authorized to record a regulatory asset comprised of its capital investment (CEF-EC Investment Deferral) and associated stranded costs (Stranded Cost Deferral).[39] In addition, as stated in paragraph 27 of the CEF-EC stipulation, "The Parties agree that the Company will defer incremental AMI-related O&M costs associated with the CEF-EC implementation into a separate regulatory

[39] CEF-EC Order at Stipulation ¶ 22.

asset ("CEF-EC O&M Regulatory Asset"), without a return, for recovery in the Company's Next Base Rate Case."[40]

Q. Is there any adjustment to the CEF-EC regulatory asset balances the Company wants to discuss?

A. Yes. Meter testing costs originally classified as part of the $707 million of estimated CEF-EC Program investment were determined not to qualify for capitalization and were recorded as an expense. The Company excluded the meter testing expenditures from the CEF-EC Program investment, so the Company is not earning a return on this investment, but the Company is seeking recovery of these prudently incurred expenditures that were always a component of the CEF-EC Program.

Q. How is the Company seeking to recover the CEF-EC regulatory assets?

A. For the CEF-EC Investment Deferral, the Company proposes to recover the regulatory asset over the life of the meter, which for AMI was set at 20 years in the CEF-EC Order.[41] For non-AMI meters, the depreciation rate (inclusive of cost of removal) is approximately 10%, so the Company proposes a 10 year recovery period for the Stranded Cost Deferral.[42] The Company will include the unamortized balance as a component of the Company's rate base in any future subsequent base rate case in accordance with the CEF-EC Order that allowed for a return of and on the regulatory asset.[43] The Company proposes to recover the Meter Testing expenses and CEF-EC O&M Regulatory Asset over a five-year period, the same period

[40] *Id.* ¶ 27.
[41] CEF-EC Order ¶ 23(c).
[42] See 2018 Rate Case Order at Stipulation Attachment B at 1 (showing total depreciation rate of 9.89 for electric account 370.00 ("Meters")).
[43] *Id.* ¶ 26.

proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $21.9 million for electric.

Adjustment No. 19: Clean Energy Future-Energy Cloud Revenue Reduction – Schedule MPM-48

Q. Is there an additional *pro forma* adjustment associated with the CEF-EC Program?

A. Yes. The implementation of AMI is forecasted to result in operational efficiencies and reductions in O&M. Some savings are reflected in the test year. See testimony of Mr. Johnson. However, the majority of these savings will occur after the AMI implementation is complete, which is not expected until after the end of the test year in this proceeding. In accordance with the CEF-EC Order, the Company is proposing an adjustment to its revenue request in this proceeding only to account for future O&M savings as a result of AMI that are not reflected in the test year.[44] This adjustment will not be implemented in a subsequent base rate case in which the actual O&M savings from the AMI implementation will be reflected in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income (after taxes) will increase by $5.1 million for electric.

[44] CEF-EC Order ¶ 19.

Adjustment No. 20: Clean Energy Future – Electric Vehicle Amortization – Schedule MPM-49

Q. What is the CEF-EV regulatory asset?

A. As discussed above in Schedule MPM-17, the Company was authorized to record a regulatory asset on its CEF-EV investment ("CEF-EV Regulatory Asset"). In addition, as stated in paragraph 29 of the CEF-EV Stipulation, "The Company will defer incremental CEF-EV-related O&M costs as described above in paragraph 15 ("CEF-EV O&M Regulatory Asset"), with a monthly carrying charge at the prior month 2-year treasury rate plus 60 basis points, for recovery in the Company's Next Base Rate Case."[45]

Q. How is the Company seeking to recover the CEF-EV Regulatory Asset?

A. For the CEF-EV Regulatory Asset, the Company proposes to recover the non-IT related expenditures over a 30-year life, the approved life in the deferral mechanism for Make-Ready – Service Upgrade Pole to Meter investment and the approximate weighted average life of the non-IT related investments. For the regulatory asset associated with the IT expenditures and the CEF-EV O&M Regulatory Asset, the Company proposes a five-year life, the same period proposed for other deferrals in this proceeding and the approved amortization period for the 2018 base rate case amortization.

[45] CEF-EV Order at Stipulation ¶ 29.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $4.3 million for electric.

Adjustment No. 21: Conservation Incentive Program Accrual Adjustment – Schedule MPM-50

Q. Please discuss the adjustment the Company proposes for the Conservation Incentive Program Accrual Adjustment.

A. The Company proposes an adjustment to test year Operating Income so that it removes the impact of the CIP accrual recorded during the test year.

Q. Why is this adjustment necessary?

A. As discussed above, the CIP mechanism trues up actual revenues to the BUC and BRC set in the prior base rate case. The accrual from that difference between the actual BUC and BRC and the baseline BUC and BRC is recorded to income and is included as part of test year operating revenue. As a result, the test year revenues are not reflective of the actual test year billing determinants that will set the revised BUC and BRC. Therefore, the impact of the CIP accrual, positive or negative, must be eliminated from the income statement to reflect the test year revenues at the actual billing determinants that will set the revised BUC and BRC.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $62.9 million for electric and $9.6 million for gas.

Adjustment No. 22: TAC Return Reset – Schedule MPM-51

Q. Please describe the need for the TAC Return adjustment being proposed.

A. Pursuant to the Order in PSE&G's last base rate case, PSE&G and the parties to that Order agreed that the return on the increase in rate base related excess deferred income taxes, including the ADIT associated with the Historic SHARE, will be reset at the conclusion of subsequent rate cases.[46] In accordance with that agreement, the Company will be resetting the return on the unamortized balances. The ADIT in the rate case will reflect all of the tax flowbacks that PSE&G has previously refunded to customers, resulting in increased rate base and return on rate base. Accordingly, the Company's operating revenue will reflect the earnings realized through the TAC flowbacks. The proposed adjustment will have a neutral effect as the adjustment will allow PSE&G to reduce the earnings in the TAC and move them to base rates through this proceeding.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $19.3 million for electric and $22.6 million for gas. However, this impact will be offset in the TAC.

Adjustment No. 23: Deferred Compensation & Severance Expense Adjustment – Schedule MPM-52

Q. Please discuss the adjustment the Company is proposing for Deferred Compensation & Severance Expense.

A. This adjustment is to increase operating income for the impact of deferred compensation and severance payments incurred during the test year. As noted in Section IV

[46] 2018 Rate Case Order ¶ 20.

above, the Company initiated a Voluntary Exit Incentive Program for non-represented employees that will result in the voluntary retirement of 185 utility and service company employees by December 31, 2023. The Company offered two weeks of severance pay to eligible non-represented employees for every year of service up to a maximum of 52 weeks. In addition, there are non-recurring deferred compensation costs outside of the VIEP. This *pro forma* is to remove the severance and deferred compensation expense and any associated tax savings so that there is no impact to customers from the severance and deferred compensation payments.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $1.2 million for electric and $0.7 million for gas.

Adjustment No. 24: Tax Impact of Bad Debt – Schedule MPM-53

Q. Please discuss the adjustment the Company is proposing for the tax impact of bad debt.

A. This schedule is to adjust tax expense to remove the impact of the pandemic and the moratorium on bad debt expense. The tax impact on bad debt is calculated as the bad debt expense less write-offs, multiplied by the federal tax rate. In general, the bad debt expense and write-offs move in sync (such that the reserve will increase as write-offs increase and vice versa), resulting in a minimal impact to tax expense. However, this trend reversed during the pandemic when the reserve increased significantly, while write-offs declined, resulting in a tax expense increase. While the Company deferred its increase in the bad debt reserve during the moratorium for recovery in the COVID-19 proceeding, it did not defer the significant negative tax impact. The impact will reverse over time as the write-offs and bad debt reserve get back

in sync. However, the test year does reflect a tax benefit from bad debt as the write-offs are forecasted to exceed the bad debt expense. This adjustment will ensure the tax impact of bad debt as a result of the moratorium is excluded from customer rates (since the negative impact during the moratorium was absorbed by the Company and excluded from the COVID-19 deferral request, and thus the offsetting positive benefit must be excluded from the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will decrease by $8.7 million for electric and $4.9 million for gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CREDENTIALS
OF
MICHAEL P MCFADDEN
DIRECTOR OF SALES AND REVENUE FORECASTING

I have been employed at PSEG for 15 years, serving in a number of financial positions in the company and since June 2021 have been the Director of Sales and Revenue Forecasting. In this capacity, I am responsible for overseeing the development of the PSE&G's ("the Company") electric and gas sales and revenue forecast, including the forecasted electric and gas Conservation Incentive Program ("CIP") accrual, and supervising the development of the weather impacts on the sales and revenue forecast.

Prior to joining PSE&G, I held various positions at the New Jersey Board of Public Utilities as a Utility Rate Analyst and Administrative Analyst in the Bureaus of Rates and Tariffs, where I analyzed electric and gas utility filings on a variety of matters, including cost recovery proceedings, base rate cases, management audits and any other proceedings addressing electric and gas utility rates.

I joined PSE&G in 2008 as a Senior Regulatory Analyst before being promoted to a Principal Staff Regulatory Analyst in 2012. In my roles as an analyst, I supported the development of the electric and gas cost of service study in the 2009 base rate case as well as the update of numerous revenue requirement models in support of the Company's Solar Pilot Recovery Charge and Green program Recovery Charge components and was the lead analyst supporting the Energy Strong I Program.

In 2014 I was temporarily promoted to Manager of Pricing and Economics before being transitioned to the Manager of Revenue Requirements. In my role as manager of

Revenue Requirements, I managed over 20 rate orders applicable to PSE&G including infrastructure investments, renewable energy, energy efficiency programs and societal benefits programs, several of which I have designed complex financial cost recovery models. I also managed the calculation of revenue requirements and filing and settlement of the PSE&G 2018 base rate case. Additionally, I managed business responses to discovery, prepared written testimony and oversaw post-approval implementation activities. I also supported the Connecticut contract for differences on the New Haven Peaking plants, supporting the development of the cost of service revenue requirement.

In my role as manager of Revenue Requirements I submitted pre-filed direct cost recovery testimony, as well as oral testimony, before the State of Connecticut Public Utilities Regulatory Authority ("PURA" or the "Authority") in multiple dockets. In my current role as Director of Sales and Revenue Forecasting, I have provided written cost recovery testimony supporting the Company's electric and gas CIP filings.

I hold a Bachelor of Science degree in Finance from the Rutgers University School of Business, and a Master's in Business Administration from Excelsior College.

EXHIBIT P-2
SCHEDULE MPM-02

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 9,287,110	$ 8,646,212	$ 17,933,322
Rate of Return	7.55%	7.55%	7.55%
Operating Income Requirement	$ 701,177	$ 652,789	$ 1,353,966
Pro-Forma Operating Income	$ 326,842	$ 349,631	$ 676,473
Operating Income Deficiency	$ 374,334	$ 303,158	$ 677,493
Revenue Factor	1.3947	1.3947	
Revenue Requirements	**$ 522,084**	**$ 422,815**	**$ 944,899**

EXHIBIT P-2
SCHEDULE MPM-03

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,661,725	13,072,325
Plant Held for Future Use	495	495
Accumulated Depreciation Reserve	(3,203,264)	(3,300,289)
Customer Advances	(63,736)	(63,736)
Net Plant	9,395,220	9,708,796
Working Capital:		
Cash (Lead/Lag)	925,712	925,712
Materials and Supplies	227,212	227,212
Prepayments	500	500
Net Working Capital	1,153,424	1,153,424
Deferred Taxes	(1,776,640)	(1,817,082)
Consolidated Tax Adjustment	(3,394)	(3,394)
IAP	(14,816)	(27,894)
CEF-EC	174,420	230,037
CEF-EV	31,957	43,223
Total Electric Rate Base	**8,960,172**	**9,287,110**

GAS RATE BASE
($000)

	Balance at May 31, 2024	Balance at November 30, 2024
Plant In Service	12,322,346	12,883,854
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,724,785)	(2,838,624)
Customer Advances	(24,945)	(24,945)
Net Plant	9,572,712	10,020,381
Working Capital:		
Cash (Lead/Lag)	605,322	605,322
Materials and Supplies	67,365	67,365
Prepayments	116	116
Net Working Capital	672,803	672,803
Deferred Taxes	(1,736,979)	(1,761,557)
Consolidated Tax Adjustment	-	-
IAP	(314)	(29,283)
CEF-EC	-	-
CEF-EV	-	-
GSMP II EXT	(6,906)	(256,132)
Total Gas Rate Base	**8,501,315**	**8,646,212**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-04

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$ 13,661	44.29%	4.02% *	1.78%
Customer Deposits	66	0.21%	1.40%	0.00%
Common Equity	17,121	55.50%	10.40%	5.77%
Total	$ 30,848	100.00%		7.55%

* this is a forecasted rate as of May 31, 2024 due to the current interest rate environment, but will be replaced with the actual May 31, 2024 rate in the 12+0 update.

EXHIBIT P-2
SCHEDULE MPM-05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
10/31/2023
INCLUDING NET UNAMORTIZED PREMIUM - INCLUDING AMOUNT DUE WITHIN ONE YEAR

PSE&G LONG TERM DEBT	COST OF BOND YIELD BASIS	PRINCIPAL AMOUNT OUTSTANDING	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT)	PLUS NET UNAMORTIZED SELLING EXPENSE	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE	PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	WEIGHT IN % OF PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	COST IN PERCENT
SERIES DUE 6/1/37	8.053%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0546%	0.0044%
SERIES DUE 7/1/37	5.033%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0552%	0.0028%
SERIES D DUE 7/1/35	5.373%	$250,000,000.00	($306,250.00)	($834,457.60)	($1,140,707.60)	$248,859,292.40	1.8216%	0.0979%
SERIES D DUE 12/1/36	5.838%	$250,000,000.00	($463,005.88)	($950,037.44)	($1,413,043.32)	$248,586,956.68	1.8196%	0.1062%
SERIES E DUE 5/1/37	5.922%	$350,000,000.00	($307,494.76)	($1,340,363.04)	($1,647,857.80)	$348,352,142.20	2.5499%	0.1510%
SERIES G DUE 11/1/2039	5.501%	$250,000,000.00	($428,914.11)	($1,162,475.75)	($1,591,389.86)	$248,408,610.14	1.8183%	0.1000%
SERIES G DUE 3/1/2040	5.638%	$300,000,000.00	($782,873.36)	($1,405,578.46)	($2,188,451.82)	$297,811,548.18	2.1800%	0.1229%
SERIES H DUE 5/1/2042	4.076%	$450,000,000.00	($1,785,316.54)	($2,410,980.42)	($4,196,296.96)	$445,803,703.04	3.2633%	0.1330%
SERIES H DUE 9/1/2042	3.765%	$350,000,000.00	($1,070,939.82)	($2,000,109.65)	($3,071,049.47)	$346,928,950.53	2.5395%	0.0956%
SERIES H DUE 1/1/2043	3.924%	$400,000,000.00	($1,629,397.25)	($2,249,412.64)	($3,878,809.89)	$396,121,190.11	2.8996%	0.1138%
SERIES I DUE 3/15/2024	3.915%	$250,000,000.00	($796.96)	($66,280.56)	($67,077.52)	$249,932,922.48	1.8295%	0.0716%
SERIES I DUE 6/1/2044	4.147%	$250,000,000.00	($1,628,169.04)	($1,566,199.15)	($3,194,368.19)	$246,805,631.81	1.8066%	0.0749%
SERIES J DUE 8/15/2024	3.339%	$250,000,000.00	($35,397.76)	($150,860.94)	($186,258.70)	$249,813,741.30	1.8286%	0.0611%
SERIES J DUE 11/15/2024	3.275%	$250,000,000.00	($124,722.89)	($200,757.06)	($325,479.95)	$249,674,520.05	1.8276%	0.0598%
SERIES K DUE 5/15/2025	3.179%	$350,000,000.00	($55,530.33)	($156,374.45)	($211,904.78)	$349,788,095.22	2.5604%	0.0814%
SERIES K DUE 5/1/2045	4.172%	$250,000,000.00	($893,159.63)	($1,440,237.23)	($2,333,396.86)	$247,666,603.14	1.8129%	0.0756%
SERIES K DUE 11/1/2045	4.249%	$250,000,000.00	($187,103.67)	($1,478,963.41)	($1,666,067.08)	$248,333,932.92	1.8178%	0.0772%
SERIES K 3.80% DUE 2046	3.913%	$550,000,000.00	($1,818,438.28)	($3,609,683.28)	($5,428,121.56)	$544,571,878.44	3.9862%	0.1560%
SERIES L 2.25% DUE 2026	2.443%	$425,000,000.00	($401,773.97)	($885,528.83)	($1,287,302.80)	$423,712,697.20	3.1015%	0.0758%
SERIES L 3.00% DUE 2027	3.200%	$425,000,000.00	($439,804.20)	($1,136,377.26)	($1,576,181.46)	$423,423,818.54	3.0994%	0.0992%
SERIES L 3.60% DUE 2047	3.689%	$350,000,000.00	($205,204.79)	($2,486,005.53)	($2,691,210.32)	$347,308,789.68	2.5423%	0.0938%
SERIES M 3.70% DUE 2028	3.917%	$375,000,000.00	($641,963.24)	($1,267,991.72)	($1,909,954.96)	$373,090,045.04	2.7310%	0.1070%
SERIES M 4.05% DUE 2048	4.178%	$325,000,000.00	($1,643,538.20)	($2,391,141.83)	($4,034,680.03)	$320,965,319.97	2.3494%	0.0982%
SERIES M 3.65% DUE 2028	3.817%	$325,000,000.00	($25,182.15)	($1,128,313.74)	($1,153,495.89)	$323,846,504.11	2.3705%	0.0905%
SERIES M 3.20% DUE 2029	3.412%	$375,000,000.00	($810,563.35)	($1,545,930.19)	($2,356,493.54)	$372,643,506.46	2.7277%	0.0931%
SERIES M 3.85% DUE 2049	3.939%	$375,000,000.00	($54,222.55)	($2,856,979.94)	($2,911,202.49)	$372,088,797.51	2.7237%	0.1073%
SERIES M 3.20% DUE 2049	3.320%	$400,000,000.00	($2,491,704.45)	($3,045,893.77)	($5,537,598.22)	$394,462,401.78	2.8874%	0.0959%
SERIES N 2.45% DUE 2030	2.638%	$300,000,000.00	($427,471.00)	($1,409,414.80)	($1,836,885.80)	$298,163,114.20	2.1825%	0.0576%
SERIES N 3.15% DUE 2050	3.240%	$300,000,000.00	($403,265.59)	($2,378,567.26)	($2,781,832.85)	$297,218,167.15	2.1756%	0.0705%
SERIES N 2.70% DUE 2050	2.798%	$375,000,000.00	($1,352,376.39)	($3,017,591.86)	($4,369,968.25)	$370,630,031.75	2.7130%	0.0759%
SERIES N 2.05% DUE 2050	2.156%	$375,000,000.00	($2,672,893.72)	($2,950,553.33)	($5,623,447.05)	$369,376,552.95	2.7038%	0.0583%
SERIES N 0.95% DUE 2026	1.264%	$450,000,000.00	($466,847.03)	($1,382,574.10)	($1,849,421.13)	$448,150,578.87	3.2804%	0.0415%
SERIES N 3.00% DUE 2051	3.085%	$450,000,000.00	($401,911.65)	($3,697,312.72)	($4,099,224.37)	$445,900,775.63	3.2640%	0.1007%
SERIES N 1.90% DUE 2031	2.081%	$425,000,000.00	($808,606.21)	($2,421,466.07)	($3,230,072.28)	$421,769,927.72	3.0873%	0.0643%
SERIES P 3.10% DUE 2032	3.296%	$500,000,000.00	($786,115.43)	($3,420,147.31)	($4,206,262.74)	$495,793,737.26	3.6292%	0.1196%
SERIES P 4.90% DUE 2032	5.090%	$400,000,000.00	($236,324.39)	($2,786,491.71)	($3,022,816.10)	$396,977,183.90	2.9058%	0.1479%
SERIES P 4.650% DUE 2033	4.842%	$500,000,000.00	($437,265.89)	($3,578,198.44)	($4,015,464.32)	$495,984,535.68	3.6306%	0.1758%
SERIES P 5.125% DUE 2053	5.234%	$400,000,000.00	($231,318.54)	($3,624,300.22)	($3,855,618.75)	$396,144,381.25	2.8998%	0.1518%
SERIES P 5.200% DUE 2033	5.399%	$500,000,000.00	($634,808.01)	($3,613,620.21)	($4,248,428.22)	$495,751,571.78	3.6289%	0.1959%
SERIES P 5.450% DUE 2053	5.574%	$400,000,000.00	($984,280.15)	($3,553,707.79)	($4,537,987.94)	$395,462,012.06	2.8948%	0.1614%
TOTAL PSE&G LONG TERM DEBT		**$13,765,000,700.00**	**($28,074,951.18)**	**($75,600,879.70)**	**($103,675,830.89)**	**$13,661,324,869.11**	**100.0000%**	**3.8669%**

EXHIBIT P-2
SCHEDULE MPM-06

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.213045	0.2130
Rate Counsel Assessment Rate	0.050234	0.0502
Income before State of NJ Bus. Tax	99.7367	99.7367
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7604	90.7604
Federal Income Taxes	19.0597	19.0597
Return	71.7007	71.7007
Revenue Factor	**1.3947**	**1.3947**

EXHIBIT P-2
SCHEDULE MPM-07

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,674,130	$ 12,661,725
Total Direct Additions	1,239,559	503,178
Total Transfers to Plant In-Service	(543)	0
Retirements:		
Distribution	(160,935)	(75,858)
General	(17,557)	(4,620)
Intangible	0	0
Common Plant	(72,929)	(12,100)
Total Retirements	(251,421)	(92,578)
Total Electric Utility Plant In-Service	**$ 12,661,725**	**$ 13,072,325**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 11,353,980	$ 12,322,346
Total Direct Additions	1,118,238	606,680
Total Transfers to Plant In-Service	(72)	0
Retirements:		
Production - Gas	0	0
Storage	0	0
Transmission	0	0
Distribution	(72,939)	(30,000)
General	(13,846)	(3,806)
Intangible	(3,345)	(1,466)
Common Plant	(59,670)	(9,900)
Total Retirements	(149,801)	(45,172)
Total Gas Utility Plant In-Service	**$ 12,322,346**	**$ 12,883,854**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-08

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADDITIONS TO ELECTRIC PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Distribution	$ 1,093,658	$ 362,881
General	84,479	29,704
Intangible	23,456	98,456
Customer Operations	37,815	12,138
Land & Land Rights	151	-
Total Direct Additions	**$ 1,239,559**	**$ 503,178**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Production - Gas	$ 1,029	$ -
Storage	492	-
Transmission	3,601	939
Distribution	1,025,170	558,725
General	56,677	23,639
Intangibles	329	13,446
Customer Operations	30,939	9,931
Land & Land Rights	1	0
Total Direct Additions	**$ 1,118,238**	**$ 606,680**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-09

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEPRECIATION OF ELECTRIC UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 3,165,769	$ 3,203,264
Distribution	278,111	137,039
General	27,212	14,178
Customer Operations	26,361	11,827
Total Charge to Depreciation Expense	331,684	163,044
Amortization of Intangibles	5,542	6,296
Total Depreciation Expense	337,225	169,340
Retirements	(251,421)	(92,578)
Cost of Removal (Net)	(110,068)	(46,563)
Other	61,759	35,845
Net Increase	37,495	66,044
Annualization of Depreciation		30,981
Balance - Accumulated Depreciation	**$ 3,203,264**	**$ 3,300,289**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
Beginning Balance	$ 2,669,747	$ 2,724,785
Production - Gas	2	1
Storage	418	316
Transmission	1,362	748
Distribution	203,982	108,306
General	19,766	10,606
Customer Operations	21,569	9,676
Total Charge to Depreciation Expense	247,099	129,653
Amortization of Intangibles	2,362	2,121
Total Depreciation Expense	249,461	131,774
Retirements	(149,801)	(45,172)
Cost of Removal (Net)	(49,603)	(26,197)
Other	4,981	3,784
Net Increase	55,038	64,190
Annualization of Depreciation		49,649
Balance - Accumulated Depreciation	$ 2,724,785	$ 2,838,624

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ADVANCES FOR CONSTRUCTION - ELECTRIC DISTRIBUTION *
($000)

Extension of Electric Lines	$	(63,736)
Total Electric Customer Advances for Construction	**$**	**(63,736)**

CUSTOMER ADVANCES FOR CONSTRUCTION - GAS DISTRIBUTION *
($000)

Extensions/Deposits	$	(24,945)
Total Gas Customer Advances for Construction	**$**	**(24,945)**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

EXHIBIT P-2
SCHEDULE MPM-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 227,212	$ 67,365
Total Materials and Supplies	**$ 227,212**	**$ 67,365**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

EXHIBIT P-2
SCHEDULE MPM-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	500	116
Total Prepayments	**$ 500**	**$ 116**

* 13-month Actual Average Balance (Oct. 2022 - Oct. 2023)

EXHIBIT P-2
SCHEDULE MPM-13

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year May 31, 2024	Balance Ending November 30, 2024
Electric	$ (1,776,640)	$ (1,817,082)
Gas	$ (1,736,979)	$ (1,761,557)

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas		Total
CTA Adjustment	(3,394)	-	$	(3,394)

EXHIBIT P-2
SCHEDULE MPM-15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

IAP RATE BASE ADJUSTMENT (ELECTRIC & GAS)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	13,218	25,291
Cost of Removal Expenditures	2,186	3,497
Accumulated Depreciation	51	241
Accumulated Deferred Taxes	(639)	(1,135)
Total	14,816	27,894
Rate Base Reduction	**(14,816)**	**(27,894)**
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	-	29,107
Cost of Removal Expenditures	437	437
Accumulated Depreciation	-	13
Accumulated Deferred Taxes	(123)	(274)
Total	314	29,283
Rate Base Reduction	**(314)**	**(29,283)**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EC RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
CEF-EC Investment Deferral:		
Deferred Depreciation	21,108	33,991
Deferred Interest	7,364	11,218
Carrying Charge Interest	838	1,492
Deferred Equity Return	29,405	44,792
Carrying Charge Return	2,406	4,282
Total	61,121	95,775
Stranded Cost Deferral:		
Accelerated Depreciation Expense	202,006	245,631
Depreciation Expense As Approved	(88,706)	(111,369)
Total	113,300	134,262
Rate Base Addition	**174,420**	**230,037**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CEF-EV RATE BASE ADJUSTMENT (ELECTRIC ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
ELECTRIC		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Unamortized Investment	24,651	32,611
Depreciation & Amortization	3,491	4,744
Deferred Return	3,244	4,930
Carrying Charges	571	939
Total	31,957	43,223
Rate Base Addition	**31,957**	**43,223**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-18

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GSMPII EXT RATE BASE ADJUSTMENT (GAS ONLY)
$000

	Test Year May 31, 2024	Six-Months Ending November 30, 2024
GAS		
Plant In-Service as of:	5/30/2024	11/30/2024
Rate Base as of:	5/30/2024	11/30/2024
Gross Plant	6,650	245,793
Cost of Removal Expenditures	350	12,936
Accumulated Depreciation	17	732
Accumulated Deferred Taxes	(111)	(3,330)
Total	6,906	256,132
Rate Base Reduction	**(6,906)**	**(256,132)**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC	**May 31, 2024**
Electric Operating Revenues	$ 4,218,045
Electric Operating Expenses:	
Operation Expense	$3,219,646
Maintenance Expense	$127,615
Depreciation Expense	$311,407
Amortization of Limited Term Plant	$22,160
Amortization of Property Losses	$17,686
Taxes Other Than Income Taxes	$25,686
Income Taxes	$24,851
Accretion Expense	$0
Total Electric Utility Operating Expenses	$3,749,050
Electric Utility Operating Income	$ 468,994

GAS	**May 31, 2024**
Gas Operating Revenues	$2,324,389
Gas Operating Expenses:	
Operation Expense	$1,559,327
Maintenance Expense	38,305
Depreciation Expense	233,901
Amortization of Limited Term Plant	14,209
Amortization of Regulatory Asset	7,835
Amortization of Property Losses	22,953
Amortization of Excess cost of removal	-
Taxes Other Than Income Taxes	17,288
Income Taxes	(29,384)
Total Gas Utility Operating Expenses	$1,864,434
Gas Utility Operating Income	$459,955
Net Utility Operating Income	$928,949

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DISTRIBUTION SALES BY CLASS OF BUSINESS
(KWh/Therms - 000)

Line		May 31, 2024 Electric	Gas
1	Residential	13,420,021	1,538,177
2	Commercial	21,847,389	964,063
3	Industrial	3,498,950	84,152
4	Firm Transportation Service		22,704
5	Non-Firm Transportation Service		128,549
6	Cogeneration Interruptible		25,942
7	Cogeneration Contracts		0
8	Contract Service Gas		684,425
9	Street Lighting	334,899	711
10	Total Sales to Customers	39,101,260	3,448,722
11	Interdepartmental	7,533	671
12	Total Sales	39,108,793	3,449,393

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-21

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

May 31, 2024

Line		Electric	Gas	Total
1	Residential	$ 2,508,564	$ 1,562,300	$ 4,070,864
2	Commercial	1,959,080	679,883	2,638,963
3	Industrial	219,388	44,702	264,090
4	Firm Transportation Service		3,876	3,876
5	Non-Firm Transportation Service		23,297	23,297
6	Cogeneration Interruptible		11,307	11,307
7	Cogeneration Contracts		-	0
8	Contract Service Gas		7,720	7,720
9	Street Lighting	84,809	601	85,410
10	Total Revenue from Sales to Customers	$ 4,771,841	$ 2,333,685	$ 7,105,526
11	Interdepartmental	1,127	384	1,511
12	Total Revenue from Sales	$ 4,772,968	$ 2,334,069	$ 7,107,036

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

Line		May 31, 2024 Electric	Gas
1	Residential	1,999,028	1,712,253
2	Commercial	302,889	154,037
3	Industrial	8,106	5,796
4	Firm Transportation Service		30
5	Non-Firm Transportation Service		153
6	Cogeneration Interruptible		11
7	Cogeneration Contracts		0
8	CSG		20
9	Street Lighting	10,919	16
10	Total Customers	2,320,943	1,872,316
11	Interdepartmental	1	1
12	Total Customers	2,320,944	1,872,317

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		May 31, 2024
Other Power Supply Expenses:		
Purchased Power	$	2,541,467
System Control/Load Dispatch	$	5
Total Other Power Supply Expenses	$	2,541,472
Distribution		
Operation	$	52,237
Maintenance		127,615
Total Distribution	$	179,852

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	1,148,595
Fuel Gas - Raw Materials		(46,078)
Other Gas Purchases		(208)
Other Gas Supply Expenses		273
Total Gas Supply	$	1,102,582
Gas Production		
Operation	$	-
Maintenance		1,574
Total Gas Production	$	1,574
Other Power Generation		
Liquefied petroleum gas expenses		485
Total Other Power Generation	$	485
Other Storage		
Operation	$	636
Maintenance		2,397
Total Other Storage	$	3,033
Total Production Expenses	$	1,107,674
Transmission		
Operation	$	137
Maintenance		4,087
Total Transmission	$	4,223
Distribution		
Operation	$	97,578
Maintenance		30,247
Total Distribution	$	127,825

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

May 31, 2024

	Electric	Gas	Total
Customer Accounts Expenses			
Operation:			
Meter Reading Expenses	$ 17,127	$ 12,790	$ 29,916
Customer Records and Collection Expenses	$ 82,663	$ 65,285	$ 147,948
Uncollectible Accounts	$ 93,118	$ 34,512	$ 127,630
Misc. Customer Accounts Expenses	$ 148,056	$ (2,166)	$ 145,890
Total Customer Accounts Expenses	$ 340,964	$ 110,421	$ 451,385
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 158,595	$ 136,311	$ 294,906
Misc. Cust. Service and Info. Expenses	$ 1,969	$ 1,564	$ 3,532
Total Cust. Service and Info. Expenses	$ 160,563	$ 137,874	$ 298,438
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 567	$ 453	$ 1,020
Misc. Sales Expenses	$ 105	$ 86	$ 190
Total Sales Expenses	$ 671	$ 539	$ 1,210
Total Customer Accounts and Information	$ 502,199	$ 248,834	$ 751,033

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

May 31, 2024

	Electric	Gas	Total
Salaries & Wages	$ 8,316	$ 8,624	$ 16,940
Supplies & Expenses	10,120	8,412	18,532
Outside Services	78,638	65,527	144,165
Property Insurance	1,714	292	2,007
Injuries and Damages	12,981	12,225	25,205
Pensions & Fringe Benefits	(9,139)	2,519	(6,620)
Regulatory Expenses	14,304	5,238	19,542
Duplicate Charge	(3,498)	(772)	(4,271)
General Advertising	2,364	1,854	4,218
Other Miscellaneous General	2,886	2,397	5,282
Rents	5,054	2,759	7,813
Maintenance	0	-	0
Total Administrative and General Salaries & Expenses	$ 123,738	$ 109,075	$ 232,813

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		May 31, 2024
	Depreciation	
1	Electric	$311,407
	Amortization	
2	Electric	$39,846
	Total Electric Depreciation and Amortization	**$351,252**

GAS

Line		May 31, 2024
	Depreciation	
1	Gas	$233,901
	Amortization	
2	Gas	$44,997
	Total Gas Depreciation and Amortization	**$278,898**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-27

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

May 31, 2024

Line		Electric	Gas	Total
1	Real Estate	$ 13,586	$ 4,607	$ 18,194
2	FICA	316	333	648
3	State Unemployment	11,406	11,950	23,356
4	Federal Unemployment	55	58	113
5	Miscellaneous Municipal and State Taxes	323	339	663
6	Total	$ 25,686	$ 17,288	$ 42,974

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

	May 31, 2024		
	Electric	**Gas**	**Total**
Net Income Taxes	$ 24,851	$ (29,384)	$ (4,533)

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE MPM-29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#	Pro-Forma Adjustments:	Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 468,994**	**$ 459,955**	**$ 928,949**
1	Wages	MPM-30	$ (7,362)	$ (6,747)	$ (14,109)
2	Payroll Taxes	MPM-31	(506)	(464)	(970)
3	Interest Synchronization (Tax Savings)	MPM-32	1,030	1,267	2,297
4	Pension & Fringe Benefits	MPM-33	(20,935)	(15,611)	(36,546)
5	COLI Interest Expense	MPM-34	(2,120)	(728)	(2,848)
6	Weather Normalization	MPM-35	(3,500)	4,424	924
7	Gains/Losses on Sales of Property	MPM-36	42	207	249
8	Real Estate Taxes	MPM-37	(617)	329	(288)
9	Insurance	MPM-38	(483)	(263)	(746)
10	ASB Margin	MPM-39	-	(14,762)	(14,762)
11	TSGNF Margin Sharing	MPM-40	-	(748)	(748)
12	Depreciation Rate Change	MPM-41	(44,544)	(71,386)	(115,930)
13	Test Year Amortization Adjustments	MPM-42	17,276	5,933	23,209
14	Rate Case & Management Audit Expenses	MPM-43	(189)	(150)	(339)
15	Energy Strong II / IAP Revenue Adjustment	MPM-44	30,209	-	30,209
16	BGS Admin Charge To Recon	MPM-45	220	-	220
17	Gas Bad Debt Adjustment	MPM-46	-	24,801	24,801
18	CEF-EC Amortization	MPM-47	(21,862)	-	(21,862)
19	CEF-EC Revenue Reduction	MPM-48	5,096	-	5,096
20	CEF-EV Amortization	MPM-49	(4,303)	-	(4,303)
21	CIP Revenue Accrual Adjustment	MPM-50	(62,862)	(9,597)	(72,460)
22	TAC Revenue Accrual Adjustment	MPM-51	(19,250)	(22,628)	(41,877)
23	Deferred Compensation & Severance	MPM-52	1,200	682	1,882
24	Tax Impact of Bad Debt Adjustment	MPM-53	(8,693)	(4,884)	(13,577)
	Total Pro-Forma Adjustments		**$ (142,152)**	**$ (110,324)**	**$ (252,476)**
Total Pro-Forma Distribution Operating Income			**$ 326,842**	**$ 349,631**	**$ 676,473**

EXHIBIT P-2
SCHEDULE MPM-30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 4,868	$ 4,651	$ 9,519
MAST Employees	3,115	2,976	6,091
Service Company Employees Charged to PSE&G	2,258	1,758	4,015
Operating Expense Increase before Taxes	$ 10,240	$ 9,385	$ 19,625
Income Taxes	2,879	2,638	5,517
Operating Income Increase (Decrease) After Taxes	**$ (7,362)**	**$ (6,747)**	**$ (14,109)**

EXHIBIT P-2
SCHEDULE MPM-31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 335	$ 320	$ 654
MAST Employees	214	205	419
Service Company	155	121	276
Operating Expense Increase before Taxes	$ 704	$ 645	$ 1,349
Income Taxes	198	181	379
Operating Income Increase (Decrease) After Taxes	**$ (506)**	**$ (464)**	**$ (970)**

EXHIBIT P-2
SCHEDULE MPM-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 3
Interest Synchronization (Tax Savings)
($000)

Electric Rate Base				$ 9,287,110
	Percent	**Embedded Cost**	**Weighted Cost**	
Debt Components:				
Long Term Debt	44.29%	4.02%	1.78%	
Customer Deposits	0.21%	1.40%	0.00%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 165,615
Less: Test Period Interest Expense				161,951
Net Interest Expense Increase / (Decrease)				$ 3,664
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,030

Gas Rate Base				$ 8,646,212
	Percent	**Embedded Cost**	**Weighted Cost**	
Debt Components:				
Long Term Debt	44.29%	4.02%	1.78%	
Customer Deposits	0.21%	1.40%	0.00%	
Total Weighted Cost of Debt				1.78%
Annualized Interest Expense				$ 154,186
Less: Test Period Interest Expense				149,680
Net Interest Expense Increase / (Decrease)				$ 4,506
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,267

EXHIBIT P-2
SCHEDULE MPM-33

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 4
Pension and Fringe Benefits
($000)

	Electric	Gas	Total
Rate Year			
Pensions	$ (7,869)	$ (5,909)	$ (13,777)
Pensions - Service Company	$ 3,148	$ 2,669	$ 5,817
OPEB	$ (1,098)	$ (940)	$ (2,038)
OPEB - Service Company	$ 369	$ 322	$ 690
Medical	$ 20,197	$ 19,844	$ 40,041
Medical - Service Company	$ 3,999	$ 3,283	$ 7,282
Dental	$ 656	$ 644	$ 1,300
Dental - Service Company	$ 158	$ 130	$ 289
Thrift	$ 5,050	$ 4,961	$ 10,011
Thrift - Service Company	$ 1,350	$ 1,108	$ 2,458
Long Term Disability	$ 371	$ 364	$ 735
Long Term Disability - Service Company	$ 134	$ 110	$ 244
Group Life Insurance	$ 196	$ 192	$ 388
Group Life Insurance - Service Company	$ 71	$ 59	$ 130
Workers Compensation	$ 2,397	$ 2,355	$ 4,752
Workers Compensation - Service Company	$ 98	$ 81	$ 179
Benefits Other	$ 2,270	$ 2,230	$ 4,500
Benefits Other - Service Company	$ 475	$ 390	$ 865
	$ 31,972	$ 31,894	$ 63,866
Less: Test Year			
Pensions	$ (21,136)	$ (15,716)	$ (36,852)
Pensions - Service Company	$ 2,346	$ 1,899	$ 4,245
OPEB	$ (11,830)	$ (9,773)	$ (21,602)
OPEB - Service Company	$ 184	$ 159	$ 344
Medical	$ 17,914	$ 18,984	$ 36,897
Medical - Service Company	$ 3,840	$ 3,046	$ 6,886
Dental	$ 621	$ 649	$ 1,270
Dental - Service Company	$ 148	$ 118	$ 266
Thrift	$ 4,654	$ 4,855	$ 9,509
Thrift - Service Company	$ 1,221	$ 969	$ 2,190
Long Term Disability	$ 361	$ 379	$ 740
Long Term Disability - Service Company	$ 126	$ 100	$ 225
Group Life Insurance	$ 173	$ 182	$ 355
Group Life Insurance - Service Company	$ 58	$ 46	$ 104
Workers Compensation	$ 1,726	$ 1,808	$ 3,533
Workers Compensation - Service Company	$ 35	$ 28	$ 63
Benefits Other	$ 2,114	$ 2,215	$ 4,330
Benefits Other - Service Company	$ 295	$ 233	$ 528
	$ 2,851	$ 10,179	$ 13,030
Increase in Test Year Operating Expenses	$ 29,121	$ 21,715	$ 50,836
Income Taxes	$ 8,186	$ 6,104	$ 14,290
Operating Income Increase (Decrease) After Taxes	**$ (20,935)**	**$ (15,611)**	**$ (36,546)**

EXHIBIT P-2
SCHEDULE MPM-34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric	Gas	Total
Net Credit in Test Year			
Administrative & General Expenses	(3,737)	(1,063)	(4,800)
Tax Savings on COLI	(386)	(133)	(518)
Total Benefit	(4,123)	(1,196)	(5,318)
Interest Charges	2,120	728	2,848
Net Benefit	$ (2,003)	$ (468)	$ (2,470)
Operating Income Increase (Decrease) After Taxes	**$ (2,120)**	**$ (728)**	**$ (2,848)**

EXHIBIT P-2
SCHEDULE MPM-35

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas	Total
Actual Distribution Revenues	$ 984,919	$ 905,399	$ 1,890,317
Weather Normalized Distribution Revenues	$ 980,050	911,552	1,891,603
Increase (Decrease) in Test Year Margin Revenue	$ 4,869	$ (6,154)	$ (1,285)
Income Taxes	1,369	(1,730)	(361)
Operating Income Increase (Decrease) After Taxes	$ (3,500)	$ 4,424	$ 924

EXHIBIT P-2
SCHEDULE MPM-36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 7
Gains/Losses on Sales of Property
($000)

	Electric	Gas	Total
Five-Year Average - Book Gain/(Loss)	$ 116	$ 577	$ 693
Income Taxes	33	162	195
Net Income/(Loss)	$ 83	$ 415	$ 498
Operating Income Increase (Decrease) After Taxes	**$ 42**	**$ 207**	**$ 249**

EXHIBIT P-2
SCHEDULE MPM-37

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 8
Real Estate Taxes
($000)

	Electric	Gas	Total
Rate Year Property Taxes	$ 14,444	$ 4,150	$ 18,594
Test Year Property Taxes	$ 13,586	$ 4,607	$ 18,194
Operating Expense Increase Before Taxes	$ 858	$ (457)	$ 400
Income Taxes	241	(129)	113
Operating Income Increase (Decrease) After Taxes	**$ (617)**	**$ 329**	**$ (288)**

EXHIBIT P-2
SCHEDULE MPM-38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 9
Insurance
($000)

	Electric	Gas	Total
Insurance Premium Expense	$ 6,933	$ 4,047	$ 10,981
Test Year Insurance Premium Expense	6,262	3,682	9,943
Operating Expense Increase Before Taxes	$ 671	$ 366	$ 1,037
Income Taxes	189	103	292
Operating Income Increase (Decrease) After Taxes	**$ (483)**	**$ (263)**	**$ (746)**

EXHIBIT P-2
SCHEDULE MPM-39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric	Gas	Total
ASB Margin by Appliance	$ 50,528	$ 41,067	$ 91,595
ASB Margin % Above-the-Line	50%	50%	
Above the Line ASB Margin	$ 25,264	$ 20,533	$ 45,798
ASB Margin in Test Year	$ 25,264	$ 41,067	$ 66,331
ASB Above-the-Line Margin	$ -	$ (20,533)	$ (20,533)
Income Taxes	-	(5,772)	(5,772)
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (14,762)**	**$ (14,762)**

EXHIBIT P-2
SCHEDULE MPM-40

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 11
TSG-NF Margin - Gas
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (1,041)	$ (1,041)
Income Taxes	-	293	293
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (748)**	**$ (748)**

EXHIBIT P-2
SCHEDULE MPM-41

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 315,435	$ 261,017	$ 576,451
Test Year Depreciation Expense	$ 311,407	$ 233,901	$ 545,308
Annualization of Current Depreciation Rates	$ 4,028	$ 27,115	$ 31,143
Depreciation Expense at Proposed Rates	$ 373,368	$ 333,200	$ 706,568
Operating Expense Increase (Decrease) for Proposed Rates	$ 57,933	$ 72,184	$ 130,117
Operating Income Increase (Decrease) Before Taxes	$ (61,961)	$ (99,299)	$ (161,260)
Income Taxes	$ (17,417)	$ (27,913)	$ (45,330)
Operating Income Increase (Decrease) After Taxes	**$ (44,544)**	**$ (71,386)**	**$ (115,930)**

EXHIBIT P-2
SCHEDULE MPM-42

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 13
Test Year Amortization Adjustments
($000)

	Electric	Gas	Total
Test Year Amortizations			
BRC Settlement	$ 20,040	$ 7,296	$ 27,335
Community Solar	$ 164	$ -	$ 164
CEF-EE IT	$ 3,828	$ 957	$ 4,784
Test Year Amortizations Total	$ 24,031	$ 8,253	$ 32,284
Operating Expense Increase Before Taxes	$ (24,031)	$ (8,253)	$ (32,284)
Income Taxes	$ (6,755)	$ (2,320)	$ (9,075)
Operating Income Increase (Decrease) After Taxes	**$ 17,276**	**$ 5,933**	**$ 23,209**

EXHIBIT P-2
SCHEDULE MPM-43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 14
Rate Case & Management Audit Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 244	$ 244	$ 488
Management Audit Expenses	$ 880	$ 720	$ 1,600
Amortization Period	3	3	3
Annual Amortization	$ 375	$ 321	$ 696
Test Year Rate Case Expense	$ 112	$ 112	$ 224
Operating Expense Decrease Before Taxes	$ (263)	$ (209)	$ (472)
Income Taxes	$ (74)	$ (59)	$ (133)
Operating Income Increase (Decrease) After Taxes	**$ (189)**	**$ (150)**	**$ (339)**

EXHIBIT P-2
SCHEDULE MPM-44

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 15
Energy Strong II / IAP Revenue Adjustment
($000)

	Electric	Gas	Total
ESII Roll-In #4 (Annualizing Revenue from Jun23 - Oct23)	8,792	-	8,792
IAP Roll-In #1 (Annualizing Revenue from Jun23 - Mar24)	6,256	-	6,256
ESII Roll-In #5 (Annualizing Revenue from Jun23 - Apr24)	26,973	-	26,973
Operating Revenue Increase Before Taxes	42,022	-	42,022
Income Taxes	(11,812)	-	(11,812)
Operating Income Increase (Decrease) After Taxes	**$ 30,209**	**$ -**	**30,209**

EXHIBIT P-2
SCHEDULE MPM-45

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 16
BGS Administrative Expense Adjustment
($000)

	Electric	Gas	Total
BGS Administrative Expense	$ (307)	$ -	$ (307)
Operating Expense Decrease Before Taxes	$ (307)	$ -	$ (307)
Income Taxes	(86)	-	(86)
Operating Income Increase (Decrease) After Taxes	**$ 220**	**$ -**	**$ 220**

EXHIBIT P-2
SCHEDULE MPM-46

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 17
Gas Bad Debt Adjustment
($000)

	Electric	Gas	Total
Gas Bad Debt	$ -	$(34,499)	$ (34,499)
Operating Expense Decrease Before Taxes	$ -	$(34,499)	$ (34,499)
Income Taxes	-	(9,698)	(9,698)
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ 24,801**	**$ 24,801**

EXHIBIT P-2
SCHEDULE MPM-47

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Amortization of CEF-EC Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EC Regulatory Assets			
CEF-EC Monthly Investment Deferral	$ 95,775	$ -	$ 95,775
Meter Testing O&M	$ 18,250	$ -	$ 18,250
Stranded Cost Deferral	$ 134,262	$ -	$ 134,262
O&M Regulatory Asset	$ 35,440	$ -	$ 35,440
Total CEF-EC Regulatory Assets	$ 283,726	$ -	$ 283,726
Amortization Period			
CEF-EC Monthly Investment Deferral	20	0	20
Meter Testing O&M	5	0	5
Stranded Cost Deferral	10	0	10
O&M Regulatory Asset	5	0	5
Annual Amortization			
CEF-EC Monthly Investment Deferral	$ 4,789	$ -	$ 4,789
Meter Testing O&M	$ 3,650	$ -	$ 3,650
Stranded Cost Deferral	$ 13,426	$ -	$ 13,426
O&M Regulatory Asset	$ 7,088	$ -	$ 7,088
Total Annual Amortization	$ 28,953	$ -	$ 28,953
Carrying Charge:			
Average Deferred Balance During Test Year	$ 26,845	$ -	$ 26,845
Deferred Tax Benefit	$ (7,546)	$ -	$ (7,546)
Average Net of Tax Deferred Cost Balance	$ 19,299	$ -	$ 19,299
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 1,457	$ -	$ 1,457
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 30,410	$ -	$ 30,410
Income Taxes	$ 8,548	$ -	$ 8,548
Operating Income Increase (Decrease) After Taxes	**$ (21,862)**	**$ -**	**$ (21,862)**

EXHIBIT P-2
SCHEDULE MPM-48

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
CEF-EC Revenue Reduction
($000)

	Electric	Gas	Total
Future Savings Revenue Offset	$ (7,088)	$ -	(7,088)
Income Taxes	(1,992)	-	(1,992)
Operating Income Increase (Decrease) After Taxes	**$ 5,096**	**$ -**	**$ 5,096**

EXHIBIT P-2
SCHEDULE MPM-49

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Amortization of CEF-EV Program Regulatory Assets
($000)

	Electric	Gas	Total
CEF-EV Regulatory Assets			
Residential Smart Charging	$ 26,624	$ -	$ 26,624
Mixed Use	$ 5,809	$ -	$ 5,809
DCFC & C&I Rebate	$ 6,368	$ -	$ 6,368
IT Systems	$ 4,422	$ -	$ 4,422
O&M	$ 16,766	$ -	$ 16,766
Total CEF-EV Regulatory Assets	$ 59,989	$ -	$ 59,989
Amortization Period			
Residential Smart Charging	30	0	30
Mixed Use	30	0	30
DCFC & C&I Rebate	30	0	30
IT Systems	5	0	5
O&M	5	0	5
Annual Amortization			
Residential Smart Charging	$ 887	$ -	$ 887
Mixed Use	$ 194	$ -	$ 194
DCFC & C&I Rebate	$ 212	$ -	$ 212
IT Systems	$ 884	$ -	$ 884
O&M	$ 3,353	$ -	$ 3,353
Total Annual Amortization	$ 5,531	$ -	$ 5,531
Carrying Charge:			
Average Deferred Balance During Test Year	$ 8,383	$ -	$ 8,383
Deferred Tax Benefit	$ (2,357)	$ -	$ (2,357)
Average Net of Tax Deferred Cost Balance	$ 6,027	$ -	$ 6,027
Weighted Average Cost of Capital	7.55%	7.55%	7.55%
Annual Amortization Carrying Charge	$ 455	$ -	$ 455
Test Year Expense	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 5,986	$ -	$ 5,986
Income Taxes	$ 1,683	$ -	$ 1,683
Operating Income Increase (Decrease) After Taxes	**$ (4,303)**	**$ -**	**$ (4,303)**

EXHIBIT P-2
SCHEDULE MPM-50

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 21
CIP Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
CIP Revenue Accrual in Test Year	$ 87,442	$ 13,350	$ 100,792
Operating Expense Decrease Before Taxes	$ 87,442	$ 13,350	$ 100,792
Income Taxes	24,580	3,753	28,333
Operating Income Increase (Decrease) After Taxes	**$ (62,862)**	**$ (9,597)**	**$ (72,460)**

EXHIBIT P-2
SCHEDULE MPM-51

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 22
TAC Revenue Accrual Adjustment
($000)

	Electric	Gas	Total
TAC Revenue Accrual in Test Year	$ 26,846	$ 32,070	$ 58,916
Operating Expense Decrease Before Taxes	$ 26,846	$ 32,070	$ 58,916
Income Taxes	7,596	9,443	17,038
Operating Income Increase (Decrease) After Taxes	**$ (19,250)**	**$(22,628)**	**$ (41,877)**

EXHIBIT P-2
SCHEDULE MPM-52

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 23
Deferred Compensation & Severance Expense
($000)

	Electric	Gas	Total
Removal of Deferred Compensation in Test Year	$ 3,726	$ 3,465	$ 7,191
Removal of Severance Expense in Test Year	$ (5,395)	$ (4,414)	$ (9,809)
Operating Expense Decrease Before Taxes	$ (1,669)	$ (949)	$ (2,618)
Income Taxes	(469)	(267)	(736)
Operating Income Increase (Decrease) After Taxes	**$ 1,200**	**$ 682**	**$ 1,882**

EXHIBIT P-2
SCHEDULE MPM-53

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 24
Tax Impact of Bad Debt Adjustment
($000)

	Electric	Gas	Total
Tax Bad Debt in Test Year	$ 8,693	$ 4,884	$ 13,577
Operating Expense Decrease After Taxes	$ 8,693	$ 4,884	$ 13,577
Operating Income Increase (Decrease) After Taxes	**$ (8,693)**	**$ (4,884)**	**$ (13,577)**

Schedule MPM-54E

2023 Rate Case - Baseline Revenue / Customer				
Month	**RS & RHS**	**RLM**	**GLP**	**LPLS**
Jun	$19.2	$21.3	$86.8	$1,811.6
Jul	$48.7	$90.0	$177.7	$2,863.2
Aug	$61.6	$106.3	$192.7	$3,665.3
Sep	$58.8	$129.0	$200.5	$3,935.7
Oct	$39.9	$84.5	$190.7	$3,910.0
Nov	$19.0	$18.1	$53.1	$1,833.0
Dec	$19.1	$18.1	$40.4	$789.6
Jan	$24.3	$22.8	$41.3	$768.9
Feb	$26.4	$25.6	$41.9	$756.6
Mar	$21.8	$22.1	$40.0	$774.0
Apr	$22.0	$21.1	$41.7	$808.8
May	$17.8	$17.3	$39.5	$759.8
TOTAL ANNUAL	**$378.8**	**$576.3**	**$1,146.3**	**$22,676.5**

Schedule MPM-54G

		2023 Rate Case - Baseline Use / Customer		
		RSG	**GSG**	**LVG**
Oct-23	Oct	44.6	71.9	2,152.7
Nov-23	Nov	94.0	209.7	3,558.7
Dec-23	Dec	143.9	337.9	5,245.4
Jan-24	Jan	169.7	401.7	6,245.7
Feb-24	Feb	150.6	352.6	5,950.6
Mar-24	Mar	120.2	296.3	5,273.9
Apr-24	Apr	65.2	156.0	3,130.1
May-24	May	37.3	85.9	2,087.8
Jun-23	Jun	21.3	57.7	1,173.9
Jul-23	Jul	18.6	47.3	1,313.9
Aug-23	Aug	16.8	50.9	1,289.1
Sep-23	Sep	18.7	48.0	1,322.4
	Total	**900.9**	**2,115.9**	**38,744.2**

Interest Cost Reconciliation

$M

		Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

Interest Cost Reconciliation

$M

		Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28
ln 1	Approved Rate Base - E	9,302	9,302	9,302	9,302	9,302	9,302	9,302
ln 2	Approved Rate Base - G	8,679	8,679	8,679	8,679	8,679	8,679	8,679
ln 3	Approved LTD %	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%	44.29%
ln 4	Approved Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 5	Actual Annual LTD Rate	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
ln 6 = ln 1 * ln 3 * (ln 5 - ln 4) / 12	Mmonthly Interest Deferral - E	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 7= ln 2 * ln 3 * (ln 5 - ln 4) / 12	Monthly Interest Deferral - G	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ln 8 = ln 6 + ln 7	**Total Monthly Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
ln 9 = ln 8 + prev ln 9	**Cumulative Interest Deferral**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT PANEL TESTIMONY

OF

MICHAEL A. SCHMID
VICE PRESIDENT – ASSET MANAGEMENT AND PLANNING
AND
RICARDO G. FONSECA
SENIOR DIRECTOR UTILITY FINANCE

December 29, 2023
P-3

Table of Contents

I.INTRODUCTION ..... - 1 -

II.ELECTRIC AND GAS DISTRIBUTION OPERATIONS AND PERFORMANCE..... - 4 -

A. Overview of Electric and Gas Delivery Organizations ..... - 4 -

1. Electric Distribution System ..... - 4 -

2. Gas Distribution System ..... - 7 -

B. Electric and Gas Delivery Performance, Safety and Reliability ..... - 9 -

III. CAPITAL EXPENDITURES ..... - 25 -

A. Electric and Gas Capital Budget Process/Cost Controls ..... - 25 -

B. Electric Capital Expenditures ..... - 30 -

1. Facilities Replacements ..... - 32 -

2. System Reinforcements ..... - 32 -

3. Environmental/Regulatory Category ..... - 34 -

4. Facilities Support ..... - 34 -

5. Energy Strong II (Electric) ..... - 35 -

6. Infrastructure Advancement Program ..... - 37 -

7. NJ Transit Mason Substation Replacement ..... - 38 -

C. Gas Capital Expenditures ..... - 39 -

1. Facilities Replacements ..... - 41 -

2. System Reinforcements ..... - 41 -

3. New Business ..... - 42 -

4. Environmental/Regulatory ..... - 43 -

5. Facilities Support ..... - 43 -

6. Energy Strong II (Gas) ..... - 44 -

7. GSMP I ..... - 47 -

8. IAP (Gas) ..... - 50 -

IV.OPERATION AND MAINTENANCE EXPENSE ..... - 51 -

A. Electric Distribution O&M ..... - 52 -

B. Gas Distribution O&M ..... - 55 -

C. Electric and Gas Distribution O&M Cost Control Efforts ..... - 57 -
D. Storm Restoration Costs ..... - 59 -
V. APPLIANCE SERVICE BUSINESS ..... - 63 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT PANEL TESTIMONY
OF
MICHAEL A. SCHMID
VICE PRESIDENT – ASSET MANAGEMENT AND PLANNING, AND
RICARDO G. FONSECA – SENIOR DIR UTILITY FINANCE

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael A. Schmid. My business address is 80 Park Plaza, Newark, New Jersey 07102.

Q. By whom are you employed and in what capacity?

A. I am employed by Public Service Electric and Gas Company ("PSE&G", "Public Service" or "Company") as Vice President - Asset Management and Planning.

Q. Please describe your professional responsibilities with respect to electric and gas delivery service.

A. I am responsible for ensuring the reliability of PSE&G's electric and gas delivery assets and overseeing various functions that support the provision of safe, adequate, proper and reliable electric and gas delivery service. My position is responsible for the overall management of electric and gas delivery assets and system performance. A summary of my qualifications and business experience is provided in Schedule PANEL-1.

Q. Please state your name, affiliation and business address.

A. My name is Ricardo G. Fonseca, and I am the Senior Director of Utility Finance for PSE&G. My business address is 80 Park Plaza, Newark, New Jersey 07102.

Q. Please describe your responsibilities as Senior Director of Utility Finance.

A. As the Senior Director of Utility Finance, I am responsible for PSE&G's business planning process, financial reporting and forecasting, and capital governance process. My position is responsible for the long range financial plan, short term financial forecasting, ensuring adherence to our capital governance processes, overseeing the Company's capital operations and maintenance ("O&M") spending plans, execution tracking and variance analysis. A summary of my qualifications and business experience is provided in Schedule PANEL-1.

Q. What is the purpose of your direct testimony?

A. In support of PSE&G's base rate filings for its electric and gas operations before the New Jersey Board of Public Utilities ("Board" or "BPU") Company witness Schmid will: describe the Company's electric and gas distribution operations, including a discussion of PSE&G's record of system safety, reliability and operational performance. He will also describe PSE&G's capital budgeting process and the practices followed by the Company to ensure the reasonableness of its base capital spending and accelerated infrastructure program-related capital expenditures, from planning and budgeting through the completion of construction. Company witness Fonseca supports the test year and post-test year period forecasts of electric and gas distribution capital expenditures and supports the test year electric and gas distribution-related expense component of total operations and maintenance ("O&M")

costs, including the major drivers of the distribution-related expense and the Company's efforts to mitigate those costs.[1]

Q. How is this panel testimony organized?

A. In addition to this Introduction section, the panel testimony is organized as follows:

II. Electric and Gas Distribution Operations and Performance;

III. Capital Expenditures;

IV. Operations and Maintenance Expense;

V. Appliance Service Business; and

VI. Gas Tariff Changes.

Q. Does the panel sponsor any schedules as part of your direct testimony?

A. Yes. We sponsor the following schedules, which were prepared by us or under our supervision and direction:

- Schedule PANEL-1 describes our professional qualifications and business experience;
- Schedule PANEL-2(a) sets forth electric capital expenditure levels by major category during the test year and post-test year;
- Schedule PANEL-2(b) sets forth gas capital expenditure levels by major category during the test year and post-test year;
- Schedule PANEL-3 contains the major event reports for the five storms that occurred since the Company's last base rate case as well as the cost detail summaries for each major event.
- Schedule PANEL-4(a) contains the annual and quarterly reports of the Energy Strong II Program Independent Monitor;

[1] As discussed by Company witness Michael McFadden, the test year consists of the twelve month period starting on June 1, 2023 through May 31, 2024, with adjustments to reflect changes in capital expenditures through November 30, 2024 and changes in certain expenses and revenues through August 31, 2025. Our testimony does not address any post-test year adjustments for electric or gas distribution operating costs; those adjustments are addressed by Mr. McFadden.

- Schedule PANEL-4(b) contains a copy of the most recent Energy Strong Program II Electric and Gas Quarterly Report;
- Schedule PANEL-4(c) contains a copy of the most recent Gas System Modernization Program Monthly Report;
- Schedule PANEL-4(d) contains a copy of the most recent report of the Infrastructure Advancement Program Independent Monitor;
- Schedule PANEL-4(e) contains a copy of the most recent semi-annual report for the Infrastructure Advancement Program;
- Schedule PANEL-5(a) sets forth total test year electric distribution-related O&M expense as well as expense by major cost category;
- Schedule PANEL-5(b) sets forth total test year gas distribution-related O&M expense as well as expense by major cost category.

Q. In your previous response you reference both test year and post-test year periods. What are those periods in this proceeding?

A. The test year in this proceeding consists of the twelve months ending May 31, 2024, and the post-test year period with respect to additional capital expenditures is the six months ending November 30, 2024.

II. ELECTRIC AND GAS DISTRIBUTION OPERATIONS AND PERFORMANCE

A. Overview of Electric and Gas Delivery Organizations

1. Electric Distribution System

Q. Please provide an overview of PSE&G's electric distribution system.

A. PSE&G is the largest electric utility provider in New Jersey. The Company's electric distribution service territory covers an approximately 2,600-square-mile corridor from Bergen to Gloucester Counties serving approximately 2.3 million customers in more than 230 urban, suburban and rural communities, including the State's three largest cities. Since the Company's

last electric rate case, many areas in the service territory have required significant investment, including new substations, switching stations and circuits to maintain service quality and reliability. The Company's electric distribution business operates and maintains over 40,760 conductor miles of primary distribution circuits, over 6,235 conductor miles of sub-transmission circuits, approximately 864,019 poles, and approximately 341,905 transformers. The Company's electric distribution business operates 50 switching stations, 240 substations, 474 sub-transmission circuits and 2,339 primary distribution circuits. Between 2018 and 2022, PSE&G installed 173 new primary (13kV and 4 kV) distribution circuits, 33 new sub-transmission (26 kV) circuits, seven new transmission supplied distribution substations and eight new switching stations. Section III of my testimony provides further details on the capital expenditures the Company has undertaken since its last electric base rate case.

Q. Has PSE&G's service territory experienced an increase in the number of electric customers since the Company's last base rate case in 2018?

A. From 2017 through 2022, the Company's annual average number of electric delivery customers has increased at a growth rate of approximately 1% per year, from 2,186,980 to 2,296,304. Over the five-year period from January 1, 2018 through January 1, 2023, the Company has invested an average of approximately $135 million per year to serve electric new business.

Q. Please describe the workforce and organizational structure that supports the electric distribution system.

A. The employees who physically construct, maintain and operate PSE&G's electric distribution system are organized in the following main areas: (1) Electric Operations; (2)

Asset Management & Planning, (3) Centralized Services; and (4) Delivery Projects and Construction ("DP&C").

Electric Operations consists of the men and women who physically construct, maintain and operate the distribution system. These employees are based in four operating divisions (the Southern, Central, Metro, and Palisades Divisions), each of which has multiple reporting locations to minimize travel time. These employees have primary responsibility for hands-on distribution and service activities. Personnel at these locations perform engineering, construction, operations, inspections, maintenance and repair, emergency response, meter services, and administrative activities.

Personnel in Asset Management & Planning include technical experts and specialists in various areas, and are located at the Company's General Office in Newark, the Edison Training and Development Center, and the Hadley Road office in South Plainfield, as well as all operating headquarters.

Centralized Services consist of multiple departments that support electric and gas operations. The organization includes the centralized work planning & cultural department as well as utility operations services. Employees are located in multiple locations within the PSE&G territory. This organization encompasses all the cultural transformation initiatives and departments that provide service, materials & equipment and overall support to utility operations.

The DP&C organization manages and executes new construction projects. This organization is not specific to a particular geographic area or location. DP&C engineers manage and execute various types of projects statewide. Most employees report directly to that day's work site. The organization includes an "Electric Mobile Division" whose field

workforce is supplemental to that of the four geographic Divisions, and an expanded "Projects and Construction Management" group that manages and oversees the work, and ensures adherence to planned schedules and costs. This organization combines flexibility and efficiency with strong planning and oversight to ensure a solid execution of all planned capital projects.

2. Gas Distribution System

Q. Please provide an overview of PSE&G's gas distribution system.

A. PSE&G is the largest gas utility provider in New Jersey. Its gas service territory covers approximately 2,300 square miles serving approximately 1.9 million customers in 267 urban, suburban and rural communities, including the State's three largest cities. To meet the needs of customers within this sizeable area, the Company's gas business operates and maintains over 18,150 miles of gas mains of various sizes from 3/4 inch to 42 inches in diameter; over 1.27 million service lines that total over 17,400 miles in length; and line valves, pressure regulators, meters, and associated instrumentation and corrosion protection systems. In addition, gas distribution operations encompass 56 metering and regulating stations, three Liquid Propane Air ("LPA") peak shaving plants, one Liquid Propane Gas ("LPG") storage facility, one Liquefied Natural Gas ("LNG") peak shaving facility, and 54 miles of intrastate transmission lines. Since the Company's last gas base rate case, it has made significant investments in many areas of our service territory, including the replacement of more than 495 miles of cast iron mains, 214 miles of unprotected steel mains and over 81,000 services. Section III of my testimony provides details on the capital expenditures the Company has undertaken since its last gas base rate case.

Q. Has PSE&G's service territory experienced an increase in the number of gas customers since the Company's last base rate case in 2018?

A. From 2017 through 2022, the Company's annual average number of gas delivery customers has increased at a growth rate of approximately 1% per year, from 1,784,484 to 1,857,109. Over the five-year period from January 1, 2018 through January 1, 2023, the Company has invested an average of approximately $97 million per year to serve gas new business.

Q. Please describe the workforce and organization structure that supports the gas distribution system.

A. The employees who construct, maintain and operate the gas distribution system and service customers' requirements are based in twelve (12) field headquarters throughout the service territory, strategically located to provide rapid response to emergencies 24 hours a day, seven days a week. These employees have primary responsibility for hands-on distribution and service activities. Personnel based at these locations perform construction, operation, maintenance and repair activities across the entire gas service territory. These services include new and replacement main and service installations, leak detection and repair, system design and maintenance, meter and after-meter safety services, surveys and inspections, and administrative activities associated with this work. The Company also has personnel in Asset Management and Planning that support delivery of gas into the distribution and transmission systems and are located at the General Office in Newark, at the Gas System Operations Center in Bridgewater, and at the peak shaving plants. The Asset Management and Planning employees in the General Office in Newark include employees who are responsible for asset strategy; planning & design; technical support to field operations; and management of the transmission and distribution integrity management programs.

B. Electric and Gas Delivery Performance, Safety and Reliability

Q. Please describe PSE&G's goals pertaining to the safety, reliability and operational performance of the Company's electric and gas distribution system.

A. PSE&G's business model for both electric and gas distribution reflects three fundamental goals, and the Company strives to instill these goals in all employees and contractors: (i) safety and reliability; (ii) cost control; and (iii) customer satisfaction. Simply put, PSE&G strives to provide safe, reliable and cost effective service at a very high level of customer satisfaction.

The Company's recent and planned capital investments are aligned with the State's Energy Master Plan goals and are designed to: mitigate the increasing impacts of climate change on core utility infrastructure, ensure the reliability of PSE&G's system in the wake of increasingly volatile weather, and ensure the Company's systems are poised to support new technologies and greener energy resources and jobs. PSE&G is committed to advancing the State's climate, decarbonization, and jobs goals. This is evident from: 1) the Company's evolving climate/decarbonization strategy, and 2) the Company's capital investments over the last several years, including investments to modernize and increase the resiliency of PSE&G's electric and gas distribution systems with programs such as the Second Phase of the Gas System Modernization Programs ("GSMP II"), as extended, the Energy Strong II Program ("ES II"), and the Infrastructure Advancement Program ("IAP"). Consistent with the Company's evolving climate/decarbonization strategy, PSE&G also has made significant investments in its Clean Energy Future ("CEF") programs.

The capital expenditures and distribution-related O&M expenses we discuss in this filing are consistent with these goals.

Q. How does PSE&G ensure that it meets its goals?

A. The Company relies on a combination of external and internal indicators. PSE&G reviews, monitors and assesses organizational performance based on metrics that rely largely on common industry standards and objective measures in the following key areas: safety, reliability, cost containment, and customer satisfaction. Some metrics are common to both gas and electric, while others are unique to either electric or gas operations. In all instances, there is a continuous improvement goal intended to encourage improved results year after year. The Company also has goals that are regulatory and clean energy based. Targets for gas and electric Annualized Energy Efficiency Energy Savings are approved by the BPU and Open Leaks is a metric specific in gas operations in which results are shared with the BPU semi-annually.

Q. Please describe some of the common safety goals for electric and gas distribution.

A. Common metrics for electric and gas distribution are those tied to Occupational Safety and Health Administration ("OSHA") measures such as the OSHA recordable incidence rate, which tracks the number of OSHA recordable injuries, and the OSHA Days Away Rate, which measures and tracks the severity of injuries. Because the Company strives to be within the top decile in this category, PSE&G purposely sets very challenging targets. Our Company-wide results for 2021 were top decile for OSHA Days Away Rate, but not for OSHA Recordable Incident Rate. Per our latest benchmarking data[2], PSE&G achieved top quartile in 2021. As illustrated in the charts below, both our OSHA Recordable Incidence Rate and our OSHA Days Away from Work rate (which is a measure of severity) were at or near top quartile performance in five of the past six years.

[2] 2022 OSHA data will be provided in a future update.

Chart 1

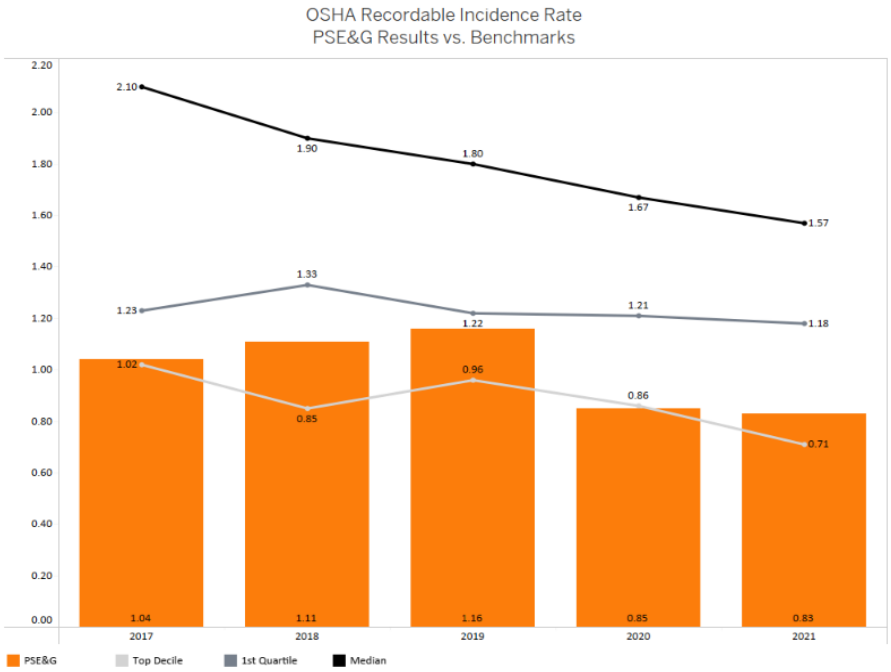
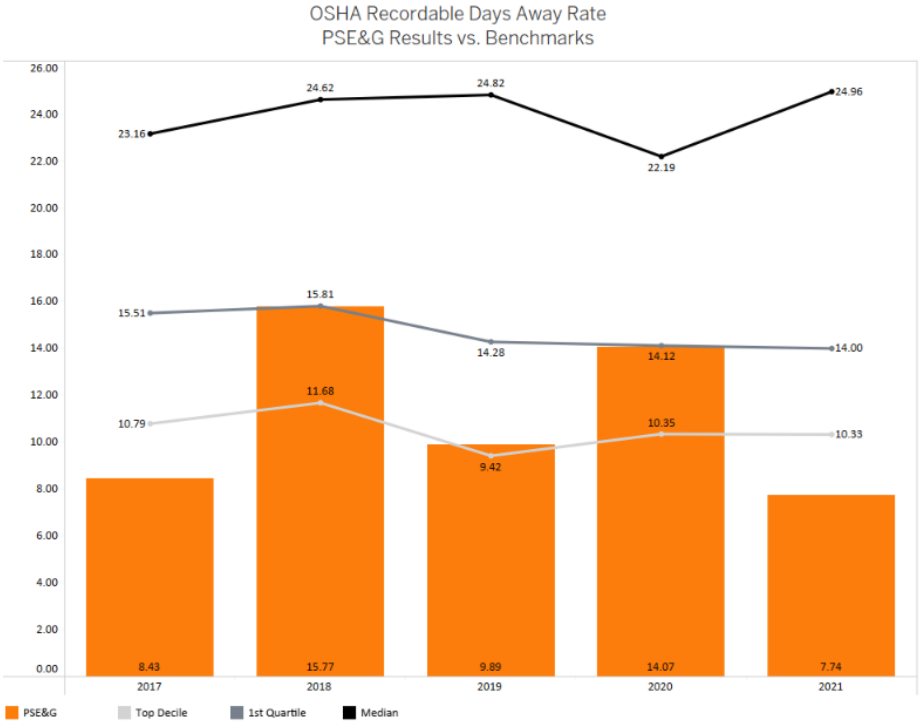
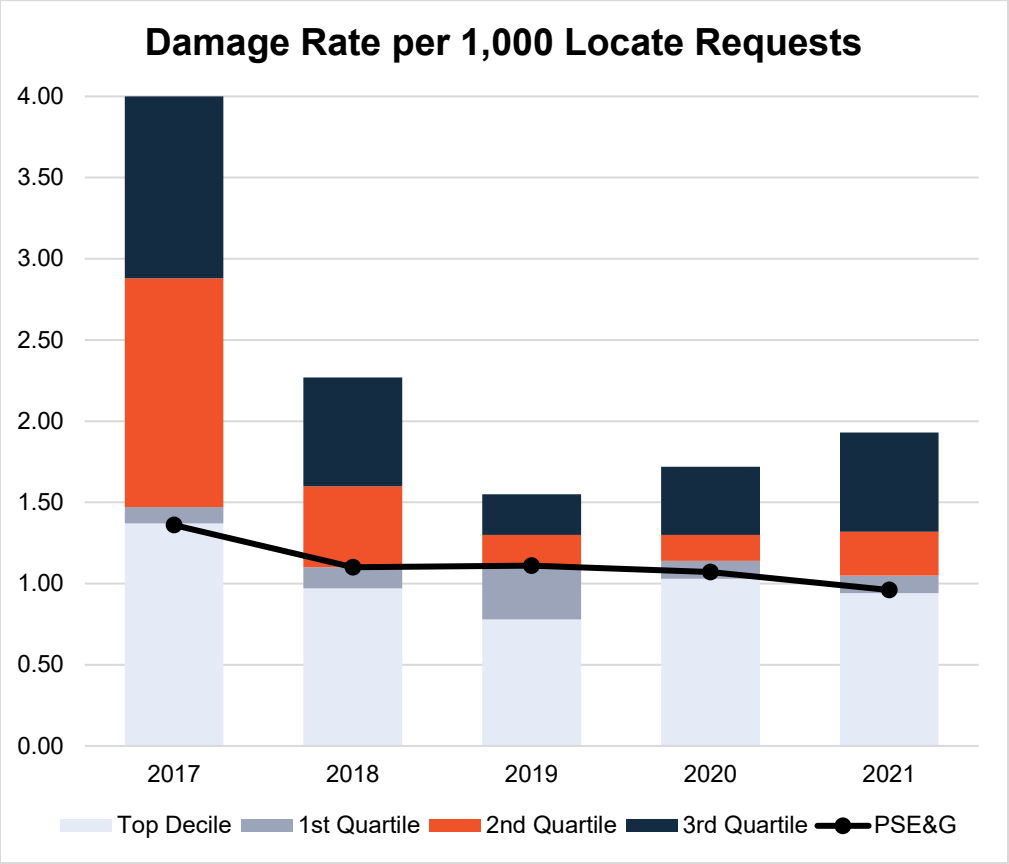


Chart 2



For the combined operations, we also measure "Damages Per 1,000 Locate Requests," which calculates the number of overall damages to gas and electric facilities per 1,000 locate requests, *i.e.*, mark-outs. The State of New Jersey requires that the location of underground installations, such as electrical and natural gas lines, be identified and marked out prior to work that involves any digging operation. Activities covered by this requirement include excavations or trenching, blasting, installation of tents, sign posts or fence posts, amongst others. Results indicate that since 2011 PSE&G's total damage rate for electric and gas combined is in the top quartile of peer panel companies.

Chart 3



Q. How does PSE&G measure the reliability of its electric distribution system?

A. The Company relies primarily on three metrics established by the Institute of Electrical and Electronic Engineers ("IEEE") to measure reliability:

System Average Interruption Duration Index ("SAIDI").
This index is based on the amount of time the average PSE&G customer experiences a sustained outage (being without power for more than five minutes) in a given year.

System Average Interruption Frequency Index ("SAIFI").
This metric represents the number of times the average PSE&G customer experiences a sustained outage in a given year; and

Customer Average Interruption Duration Index ("CAIDI").
This index represents the average outage time when customers are impacted by a sustained outage. It is determined by dividing SAIDI by SAIFI.

The Board's regulations set forth a minimum reliability level and annual reporting requirement[3] for SAIFI and CAIDI. Because the Board's annual reliability performance level targets are generally set using an individual utility's five year average, PSE&G's required targets are higher than other NJ EDCs as a result of the Company's strong historical performance, as I discuss below. The Company also measures SAIDI, with targets to improve results for all three measures as compared to the Company's past performance year after year. Beyond the requirements contained in the Board's regulations, the Company is similarly required to report system performance using these measures as part of the reporting requirements that apply to the Company's Energy Strong II Program, which is discussed later in my testimony.

[3] Each year, like all other electric utilities in New Jersey, PSE&G is required to submit an Annual System Performance Report to the Board.

Q. What do these reliability measures show?

A. The Company's performance of these indicators is addressed in detail in the testimony of Company witness Michael J. Adams. The indicators show that PSE&G has a strong and well-established track record of outstanding reliability and has continued to build upon that since the last rate case. Mr. Adams reviewed PSE&G's reported System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") to those of the other New Jersey electric companies as reported to the Energy Information Administration ("EIA") via Form 861 and to the IEEE via IEEE's annual benchmarking survey. Mr. Adams' study illustrates that for the years 2013 through 2021, PSE&G's SAIDI, SAIFI, and CAIDI reported to EIA were consistently below (better than) that of the other New Jersey electric companies that reported comparable metrics. Therefore, PSE&G's electric customers, on average, experienced interruptions of service less frequently than, and the interruptions experienced were of shorter durations than, those experienced by the customers of the other New Jersey utilities.

The results were the same based on a review of IEEE's annual benchmarking survey. PSE&G's reported SAIFI was in the first quartile of all utilities' SAIFI reported to the IEEE during each of the years 2013 to 2022, indicating that, at the very least, PSE&G was in the top 25% of all utilities surveyed. PSE&G's reported CAIDI and SAIDI were also in the first quartile when compared to the companies participating in the IEEE study.

Q. Can you discuss PSE&G's responsiveness to major storm events and emergencies?

A. PSE&G takes pride in maintaining public safety and responding rapidly to major storm events and large scale system emergencies, and working in close collaboration with state, county, and municipal organizations as well as the BPU in accomplishing these goals. The Company's response during these critical times illustrates PSE&G's commitment to providing customers with safe and reliable service and PSE&G's ability to respond to widespread damage and outages.

Since the last base rate case, the State of New Jersey has experienced a number of significant weather events requiring extraordinary preparation, recovery and restoration efforts and associated costs, including Tropical Storm Isaias, Hurricane Ida, the February 2021 Snow Storms, the June 2020 Derecho, and the July 2019 Major Storm. See Schedule PANEL-3 for the major event reports PSE&G provided to the Board for the five storms that occurred since the Company's last base rate case and the cost detail summaries for each. The Company also continues make storm hardening and resiliency investments on its system to better protect customers and the Company's systems against the effects of increasingly frequent major storms in our service territory. The hardening and resiliency efforts since 2018 include the raising and rebuilding of substations located in the FEMA flood zone, additional circuit sectionalizing to minimize customer impact and the conversion of open wire to spacer type construction for better performance during weather events. The Company's proposed treatment of the expenditures associated with the Company's storm recovery efforts since its last base rate case is discussed by Mr. McFadden and Mr. Swetz.

Q. Has PSE&G received any industry awards related to PSE&G's electric distribution reliability performance?

A. PSE&G is a participant in PA Consulting Group's national utility benchmarking program and has received the regional award for the most reliable utility in the Mid-Atlantic region/service area every year since 2002 (for 2001 performance forward), including in 2023 for performance in 2022. In 2018, PSE&G became the first public utility in the United States to obtain Support Anti-terrorism by Fostering Effective Technologies ("SAFETY") Act liability protections from the U.S. Department of Homeland Security for the deployment of physical security measures that are designed to detect, deter and recover from acts of terrorism.

In 2018, PSE&G was the recipient of the Edison Electric Institute ("EEI") Emergency Assistance Award for outstanding work assisting customers impacted by Hurricane Irma. EEI also recognized PSE&G in 2022 with the Edison Award in recognition of efforts to protect New Jersey communities and customers from extreme weather conditions. In 2022, PSE&G ranked first in the East among large utilities for both gas and electric utility residential customer satisfaction studies according to the J.D. Power 2022 studies.

Q. What indicators does PSE&G rely on to measure gas distribution safety and reliability?

A. The primary performance indicators for gas distribution are (i) gas leak reports per mile; (ii) cast iron breaks per mile; (iii) open leaks; (iv) gas damages per 1,000 locate requests; and (v) leak response time rates. The Company tracks leak data and reports it to the Board. The Company also reports the estimated volume of methane emissions from the distribution system annually as part of the Company's US EPA Greenhouse Gas Reporting Program: Subpart W reporting. Additionally, the Company tracks the following metrics of gas system safety and reliability on the Gas T&D Engineering scorecard: the number of verified times the

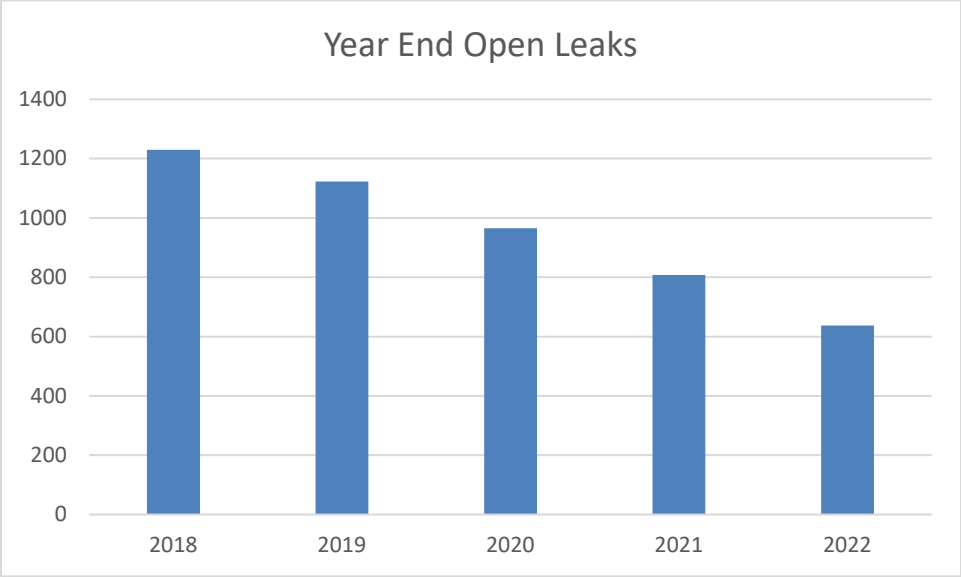
system pressure exceeds the MAOP (Maximum Allowable Operating Pressure) (not including Utilization Pressure systems); the number of localized areas experiencing unplanned pressures below design minimum (not including Utilization Pressure systems); and the number of metering and regulating ("M&R") station or Plant outages due to unplanned events.

Q. What do these measures show?

A. Every year since 2010, PSE&G has maintained cast iron main leak and break rates and unprotected steel main leak rates below the upper performance limit ("UPL") established following the Company's 2006 rate case, with the single exception of the high pressure cast iron main leak rate in 2014, which exceeded the UPL by 0.094 leaks/mile or approximately 47 leaks as a result of a very severe winter. Additionally, since 2010 the year end open Class 2 leak total has never exceeded the UPL of 1,500 leaks.

Regarding open leaks, the Gas System Modernization Program, discussed later in my testimony, stipulated that from September 30, 2015 through September 30, 2018, the Company is required to reduce its September 30, 2015 inventory of open leaks by sixty percent. The Company has far exceeded that requirement. Through September 30, 2018, this active leak inventory as stipulated in the GSMP case was reduced by 2,365 leaks or 94%. In the GSMP II program the Company is required to reduce its year-end open leak inventory by one (1) percent for each year of the program subject to a year end cap on total open leaks. The Company has again far exceeded that requirement. From January 2019 to December 2022, the year end open leaks has averaged 47% below the cap on open leaks set in the stipulation and as of December 2022 was 61% below the cap. Please see the chart below for year-end open leaks for all classes of leaks.

Chart 4

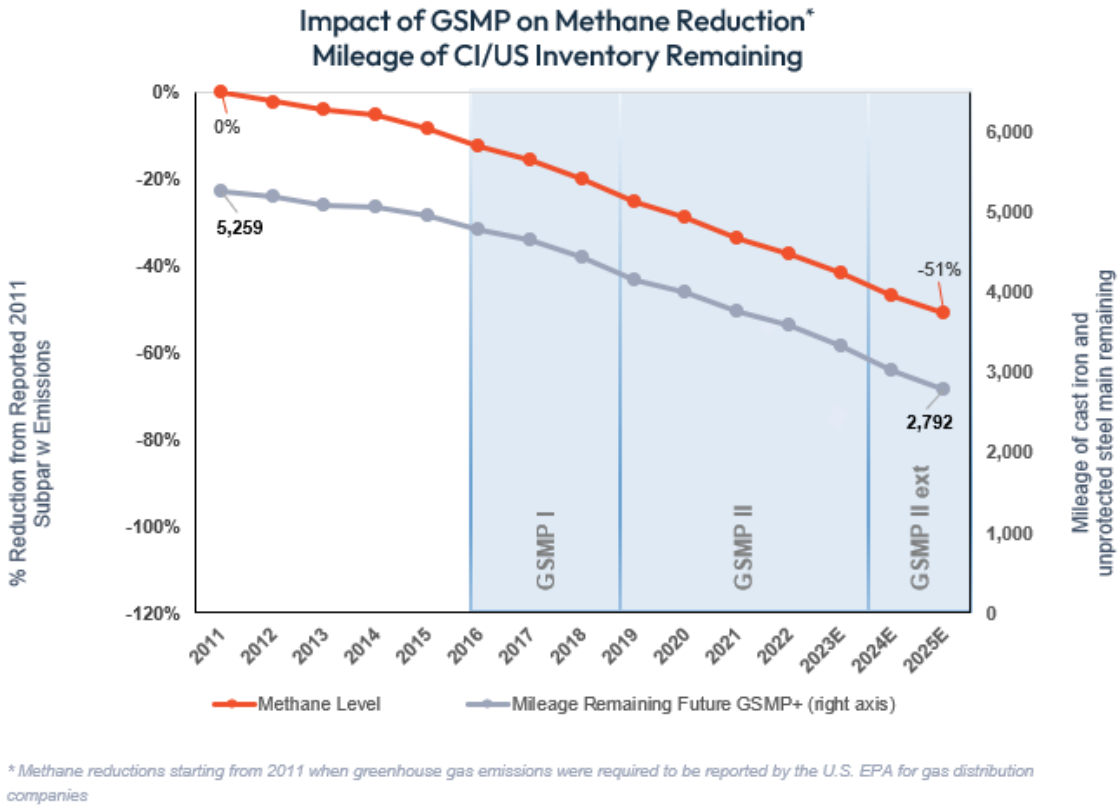


With respect to leak response times, in 2022 the Company's gas service technicians, inclusive of those who perform appliance service work, responded to over 73,618 emergency leak calls, with a 99.98% response rate within 60 minutes, which is top decile performance within our peer group. All identified leaks and hazards were made safe for our customers. Additionally, in 2022 our technicians handled over 211,000 heating related calls in both a timely and expeditious manner. We continue to offer safety checks of gas appliances for proper installation and ventilation and have actively promoted, through bill inserts, customer awareness of the dangers and causes of carbon monoxide poisoning. We conducted 5,063 emergency calls for suspected carbon monoxide emissions on customer premises in 2022. On 37% (1,875) of those calls, our responders found measurable levels of carbon monoxide present. In each instance, PSE&G responders made the premises safe.

The Company has reduced methane emissions approximately 6% annually since 2018 or a total of approximately 145,000 metric tons of Carbon Dioxide equivalent (CO2e). This correlates to the decline in miles of cast iron and unprotected steel main and services in the

distribution system as a result of the Company's accelerated replacement programs. Please see the chart below demonstrating the relationship between the main replacement under GSMP programs and methane emissions.

Chart 5



The annual number of overpressure excursions has declined from 9 in 2018 to 5 in 2022. There have been no areas experiencing unplanned pressures below design minimum in the years from 2018 through 2022 and only 2 occasions of unplanned M&R station or plant outages in this timeframe, with the last occurrence in 2020.

Q. Please discuss the Company's efforts to promote New Jersey's energy policy goals.

A. The Company recognizes and understands that many of our customers have redefined how they go about their day-to-day activities, including how and where they work, study, and

even fuel their vehicles. This shift makes the provision of safe, reliable, resilient, and sustainable energy all the more important in meeting the evolving needs of the Company's customers, and aligning with the state's goals for a clean energy future. To date, PSE&G has recognized the evolution of the state's energy policies and the Energy Master Plan and aligned its investment and operating policies accordingly, including by accelerating the modernization and decarbonization aspects of the Company's strategy with programs such as:

1. The Infrastructure Advancement Program ("IAP"), which includes "last mile" improvements (or improvements to the portion of the grid that brings power from substations to customers' homes and businesses) and updates to PSE&G's aging electric substations and gas M&R stations.

2. The Energy Strong programs, which serve to further strengthen the Company's statewide electric and gas systems to better withstand storms, improve reliability and significantly enhance resiliency. The latest iteration of the program – Energy Strong II – includes investments to harden the electric infrastructure from the effects of major weather events, improve resiliency, allow for faster restoration of outages and ensure safe and reliable service by replacing facilities when they reach the end of their service lives. Hardening work under Energy II includes rebuilding or eliminating 16 stations in flood zones, building or modernizing six M&R stations and upgrading the construction standard on some distribution circuits. Resiliency work includes technology investments that will improve field communications, make the system smarter and more efficient, and allow the grid to handle more solar and other distributed green energy sources.

3. The Gas System Modernization Programs ("GSMP"), addresses the potential safety and environmental concerns associated with leaks from aging cast iron and unprotected steel pipe in PSE&G's inventory as well as inside gas meter sets, consistent with the state's

Energy Master Plan, New Jersey's Global Warming Response Act, the 80X50 Report,[4] and federal legislation, and consistent with Governor Murphy's 2023 Executive Orders related to the State's Clean Energy goals.

4. The Clean Energy Future Programs ("CEF"), such as the CEF-Energy Efficiency Program ("CEF-EE"), CEF-Energy Cloud ("CEF-EC") (deployment of advanced metering infrastructure), and CEF-Electric Vehicles ("CEF-EV") Programs. Together, these initiatives form the basis for a clean and resilient energy future.

5. PSE&G has supported state goals on solar develop since the last rate case through ongoing customer solar interconnections. As of November 1st of 2023, PSE&G has interconnected over 83,000 solar installations with a cumulative capacity of over 1,400 MW (AC) which represents a 106% and 81% increase from 2018 in installations and capacity, respectively. These numbers reflect PSE&G's commitment to support clean energy while maintaining safe and reliable service to all customers.

Q. Please address cost containment efforts.

A. To contain increasing operating costs, the Company has employed a variety of cost control efforts to minimize customer rate impacts, while continuing efforts to provide safe, reliable and quality service to our customers. I highlight specific examples of capital and O&M-related management efforts below in sections III and IV, respectively.

[4] New Jersey's Global Warming Response Act 80x50 Report, https://dep.nj.gov/wp-content/uploads/climatechange/nj-gwra-80x50-report-2020.pdf , rel. October 15, 2020.

Q. Please address customer satisfaction.

A. In general, J.D. Power customer satisfaction results demonstrate PSE&G's strong performance and focus on improvement. PSE&G is included in J.D. Power's Customer Satisfaction Studies in the "Large Utility East" segment. J.D. Power conducts customer satisfaction surveys of (1) electric residential customers; (2) electric business customers; (3) gas residential customers; and (4) gas business customers. As discussed by Company witness Mr. Adams, among electric residential customers PSE&G was ranked in the first quartile for customer satisfaction in every year during the period 2013-2022, except for 2013 and 2014, when it ranked in the second quartile. In the most recent J.D. Power results for the calendar year 2022, electric residential customers ranked PSE&G in the first quartile (and first overall). PSE&G was ranked in the first or second quartile by its electric business customers during each of the years 2013 through 2022, including rankings in the first quartile (and second overall) by its electric business customers in the most recent survey, i.e., 2022.

Q. Does Mr. Adams also provide data on gas customer satisfaction?

A. Yes. PSE&G was ranked in the first or second quartile by its gas residential customers in each of the years 2013 through 2022. In fact, PSE&G's gas residential customer satisfaction rating improved year-over-year for nine straight years, from 2014 to 2022. In the most recent results released by J.D. Power for the calendar year 2022, gas residential customers ranked PSE&G in the first quartile (and first overall). Finally, PSE&G's gas business customer satisfaction rating improved year-over-year each year from 2019 to 2021 and was ranked in the first quartile (and third overall) in 2022.

Q. Has PSE&G received any industry awards related to PSE&G's gas distribution safety performance?

A. Yes, PSE&G has received multiple industry awards related to gas distribution safety performance since the last rate case as follows:

2022:

- American Gas Association (AGA) 2022 Leading Indicator Safety Award, in recognition of proactive commitment to enhancing safety
- AGA 2022 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2021:

- AGA 2021 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type
- 2021 bronze award in the communications category of the Chartwell Best Practices Award competition for PSE&G's 2020 gas-safety customer education campaign.

2020:

- AGA 2020 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2019:

- AGA 2019 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type

2018:

- PSE&G became the first public utility in the United States to obtain SAFETY Act liability protections from the U.S. Department of Homeland Security for the deployment of physical security measures that are designed to detect, deter and recover from acts of terrorism.
- AGA 2018 INDUSTRY LEADER ACCIDENT PREVENTION – Mega, for achieving a DART- incident rate below the industry average for its company type.

Q. Please summarize your conclusions regarding PSE&G's electric and gas distribution operational performance.

A. As an organization, PSE&G is focused on providing safe and reliable service, controlling costs, and delivering a high level of customer satisfaction. The Company continually strives to improve performance year after year to meet these goals, and has been successful in these efforts. This is evident in the two charts below from 2021. Chart 6 below illustrates PSE&G's electric SAIDI performance compared to distribution O&M while Chart 7 shows our leak response rate compared to distribution O&M. These charts demonstrate our commitment to providing excellent service at reasonable costs.

Chart 6

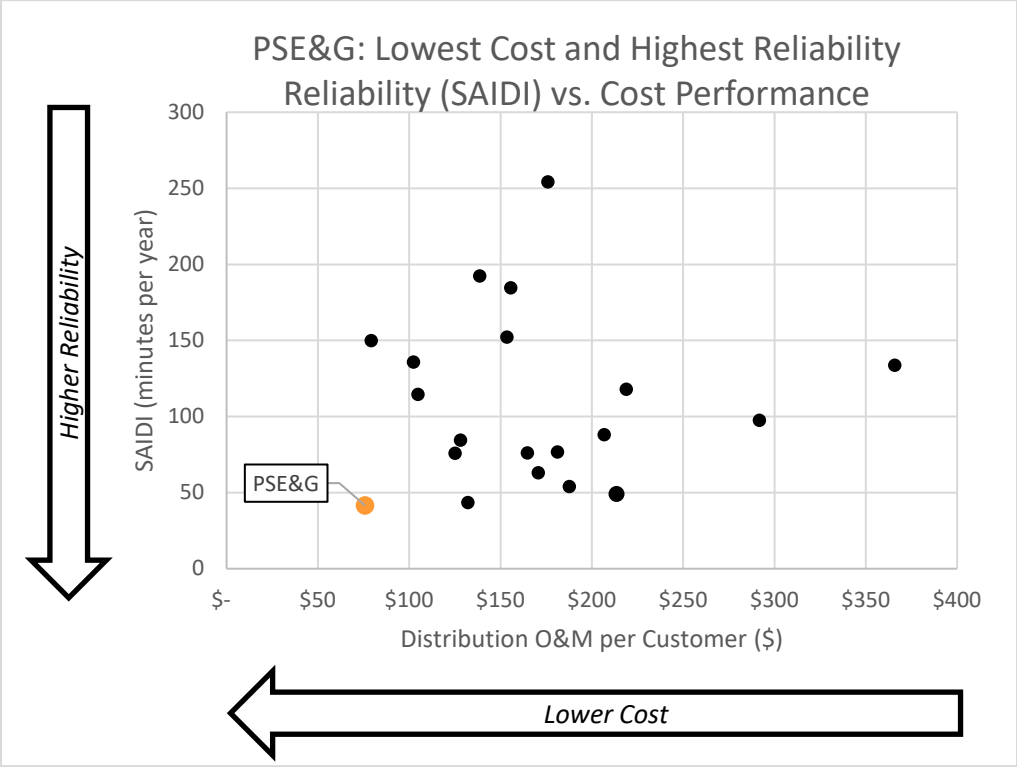
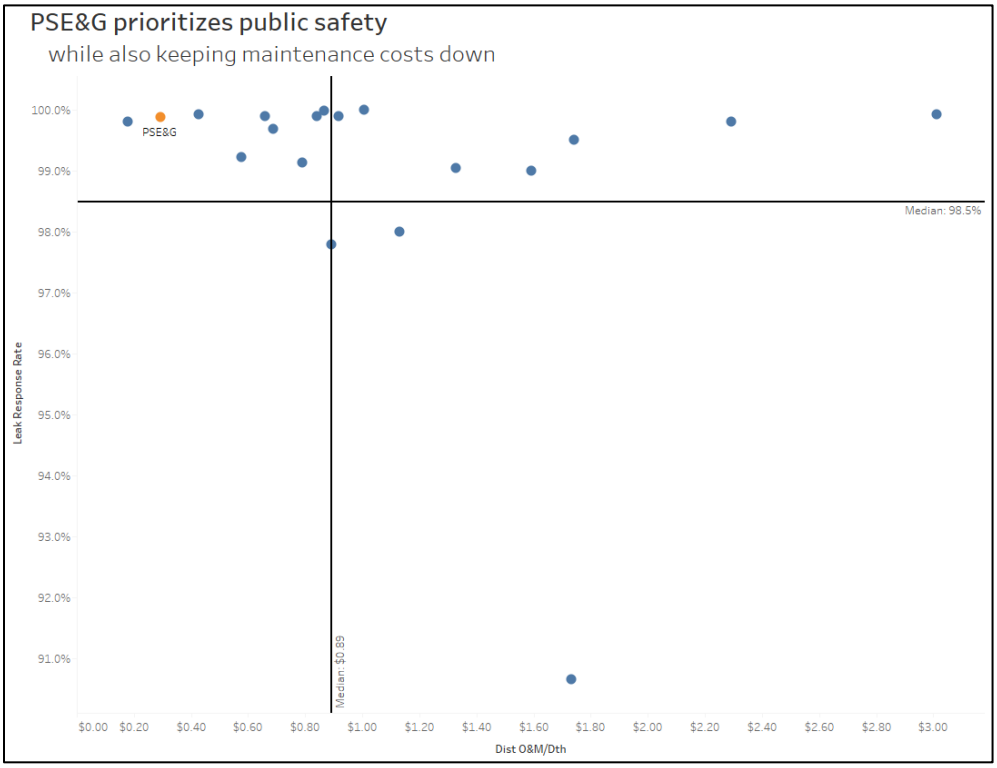


Chart 7



III. CAPITAL EXPENDITURES

A. Electric and Gas Capital Budget Process/Cost Controls

Q. How does PSE&G develop its capital budget and review, approve and monitor electric capital expenditures?

A. PSE&G has an extensive, multi-layer process to develop its annual capital plan and review, approve and monitor capital expenditures from project inception to completion. The Company's capital processes have been reviewed favorably by an independent monitor, Pegasus Global Holdings, Inc. ("Pegasus") that was retained for the Energy Strong I and Energy Strong II Programs after consultation with Board Staff and the New Jersey Division of Rate Counsel ("Rate Counsel").

Q. Why has an independent monitor considered PSE&G's capital review process?

A. The May 21, 2014 BPU Order ("Energy Strong I Order") in BPU Docket Nos. EO13020155 and GO13020156 approving the Company's initial Energy Strong Program – an accelerated infrastructure replacement program – required the Company to retain an independent monitor to review Energy Strong project development and implementation. The September 11, 2019, BPU Order in BPU Docket Nos. EO18060629 and GO18060630 ("Energy Strong II Order") (collectively, with the Energy Strong I Order, the "Energy Strong Orders"), which authorized the Company to undertake a second phase of the Energy Strong Program, similarly required the retention of an independent monitor. The Energy Strong II Order authorized the Company to continue making reliability and resiliency investments, including rebuilding and raising critical electrical equipment, installing stronger poles and wires, deploying advanced technology, building backup pipes, modernizing critical gas equipment, and improving customer service. While the requirement to retain the independent monitor derives from the Energy Strong Orders, the processes reviewed by Pegasus apply uniformly to all capital investments, not just those related to Energy Strong I and II.

Q. Has the Energy Strong independent monitor, Pegasus, documented its review?

A. Yes. The Energy Strong Orders required that the independent monitor review and report to Board Staff and Rate Counsel on cost effectiveness, efficiency, appropriate cost assignment, and other information. Since the retention of Pegasus, all of the monitor's annual and quarterly reports ("Pegasus Reports") have been submitted to Board Staff and Rate Counsel, and non-confidential copies of these reports are included herein as Schedule PANEL-4(a).

Q. What do the Pegasus Reports demonstrate?

A. Among other things, the findings contained in the Pegasus Reports support the conclusion that PSE&G's capital budgeting processes and cost control practices are comprehensive, sound, and effective. These findings are contained in Schedule PANEL-4(a).

Q. Please describe the development of the Company's capital plan.

A. To develop the annual capital budget, each year's spending for individual proposed projects is compiled and placed into one of three project categories: (i) tariff/legal projects, which are generally non-discretionary and identified through external parties (*e.g.*, to support new service, or dictated by environmental or regulatory requirements); (ii) minimum projects, which are projects required to assure immediate continuity of safe and reliable basic utility service (*e.g.*, pole replacements, replacement of defective/failed facilities); and (iii) priority projects, which are discretionary projects. Spending in all categories is based on cost estimates submitted by subject matter experts from various departments (*e.g.*, project managers, project cost engineers, system planners) within the organization. Once the annual budget is developed, it is then reviewed and approved by the Company's Utility Review Board ("URB"), which consists of senior officers of PSE&G, as well as senior officers from other key support areas.

Q. Are there additional approvals needed before a project or program in the annual capital plan can proceed?

A. Yes. Aside from the capital planning and budgeting process, specific approval must be obtained for any project or program within the capital plan. All PSE&G major capital investments, whether undertaken as base capital spending or pursuant to an accelerated infrastructure program such as Energy Strong, must be approved at the appropriate management level within the Company. The extent of approval and documentation required

is largely dependent on the expected dollar value of the investment. PSE&G's Utility Capital Review Board ("URB") reviews and approves blanket spending (aggregated spending on projects with similar repetitive work, *e.g.,* electric distribution poles, gas pipe, meters) in which individual items are each less than $5 million, and specific project investment requests where capital requests are less than $20 million. In addition, any capital investment exceeding 5% of previously approved amounts must be reported to the URB, and any investment exceeding 10% of previously approved amounts requires re-approval. The URB is required to review project alternatives and to recommend for approval projects requiring consideration by the Company's Capital Review Committee ("CRC"). The CRC is responsible for reviewing, analyzing, and approving (to the extent not otherwise required by the Company's Board of Directors, in which case the CRC recommends approval to that body) capital investments greater than $20 million. To be reviewed by the CRC, approval must have been previously given by the URB. For projects greater than $50 million, the CRC will recommend approval to the Company's Chief Operating Officer ("COO"), and for projects greater than $100 million, the Company's Board of Directors will review, analyze and approve projects accordingly.

For CRC meetings, the PSE&G Finance Department (part of PSEG Services Corporation, the Company's services company) has the responsibility to assure completeness of all project financial analyses, record CRC authorizations, and ensure project closeouts are completed. Notably, the Company uses a phased-funding approach to releasing funds for projects based on acceptable progress, and for continued project justification.

Q. Please explain how capital projects are selected and optimized.

A. The process used by PSE&G to select and prioritize electric and gas distribution capital spending plans has been in place since 2004. PSE&G selects projects by evaluating various factors, including whether the project is legally mandated, its operational requirements, and the extent to which the project supports the continued provision of safe, adequate, proper, and reliable utility service. The risk associated with not funding and performing each proposed investment is also evaluated to identify potential adverse consequences of not performing the work. PSE&G then determines the optimal portfolio combinations of work to be resourced and performed, so that value is optimized for the available level of resources within the electric and gas businesses.

Q. What protocols are followed to ensure that PSE&G's expenditures are reasonable and cost effective?

A. The policies and procedures that PSE&G has in place to ensure effective cost control for our capital projects are set forth in the Pegasus Annual Report included with Schedule PANEL-4(a). The Company undertakes a comprehensive approach applying cost control measures to all phases of its major capital projects, including Project Initiation, Design, Scheduling, Contracting, Material Procurement, and Construction. For example, during the Project Initiation phase, projects undergo a rigorous process of funding requests and project review and are subject to estimating procedures that utilize four cost estimating phases through which, as a project moves towards certainty, the tighter the cost estimate needs to become. Numerous procedures are also applied during the Design, Scheduling, Contracting, Material Procurement, and Construction phases to facilitate cost control, including project scope and invoice management, competitive bidding, and strict construction oversight. The Company's

policies and procedures are extensive, well documented and afford the Company the opportunity to discern and mitigate potential project cost overruns and ensure that the Company's expenditures are reasonable and cost effective.

Q. Please describe some of the specific practices the Company uses to control costs associated with electric and gas distribution capital expenditures.

A. The Company utilizes various methods to cost-effectively manage its electric and gas distribution capital program including, where possible, undertaking planned rather than reactive capital work and coordinating capital programs between electric and gas operations, as well as with third parties. PSE&G also benchmarks costs to help track and manage capital expenditures. For example, the Company tracks cost per mile and cost per foot information, allowing monitoring of capital expenditures in relation to original budgets and to make appropriate changes where possible.

The Company's gas distribution business has established a group dedicated to project management and implemented new software for managing project and construction activities. PSE&G has also partnered with critical material providers to strategically source construction supplies, helping to obtain bulk pricing and receive direct deliveries to job sites to help facilitate cost control and minimize risk of construction work delays.

B. Electric Capital Expenditures

Q. Please describe PSE&G's electric capital spending since its last base rate case.

A. The Company's electric distribution rates were last reset in a base rate case approved by the Board in 2018. Since that time, PSE&G has invested a substantial amount of capital -- approximately $3.3 billion, of which $2.4 billion was placed in service, net of retirements -- in

new electric distribution plant and services equipment through May 31, 2023. The majority of these investments were for various projects focused on maintaining and improving reliability. As reflected on Schedule PANEL-2(a), the Company projects that during the period June 1, 2023 through November 30, 2024, it will complete investments in electric distribution plant totaling $2.0 billion. This level of investment was and is required to maintain and further enhance safe and reliable service to customers, support a continuation of the Company's infrastructure hardening and modernization efforts, and facilitate PSE&G's ongoing commitment to provide excellent service to customers.

Q. Please summarize the Company's test year and post-test year electric capital expenditures set forth on Schedule PANEL-2(a).

A. As reflected on Schedule PANEL-2(a), the Company expects to incur electric capital expenditures of approximately $1.4 billion during the test year and approximately $0.6 billion in the post-test year period in various spending categories that are described further below. In service test year investments amount to $1.2 billion and post-test year investments total $0.5 billion. The test year and known and measurable post-test year expenditures that will be placed in-service by November 30, 2024 are reflected in Mr. McFadden's Schedule MPM-7.

Q. What are the test year pre- and post-test year electric capital expenditure categories reflected on Schedule PANEL-2(a)?

A. The test year, pre- and post-test year expenditure categories reflected on Schedule PANEL-2(a) include the major categories of electric investment described below:

1. Facilities Replacements

Q. Please explain the electric Facilities Replacements expenditures reflected on Schedule PANEL-2(a) for the test year, pre- and post-test year periods.

A. Test year, pre- and post-test year expenditures in this category involve the replacement of defective or aging equipment and facilities to maintain the integrity of the electric infrastructure and to replace large equipment failures that may occur. The expenditures also include ongoing work to replace specific types of electric equipment, such as capacitors, street lights, poles, transformers, breakers, and replacement meters; underground facilities such as cables; and inside plant and substation facilities.

2. System Reinforcements

Q. Please explain the electric System Reinforcement expenditures reflected on Schedule PANEL-2(a) for the test year and post-test year periods.

A. System Reinforcements involve expenditures associated with increasing electric system capacity to accommodate customers' peak demand and capacity requirements and enhance the system's ability to provide high levels of reliable service under adverse conditions, ensuring that the Company continues to meet its reliability goals and design criteria. These expenditures predominantly include investments in electric facilities such as new substations and work done to improve the poorest performing circuits. These circuits are defined as the 4kV and 13kV circuits in each division with the poorest combined performance in terms of number of outages and total customer hours of interruption. Other expected system reinforcement funding areas include pole reinforcements, animal guards, and other reliability improvement programs.

New Business Category

Q. Please explain the types and amounts of costs associated with the electric New Business category reflected on Schedule PANEL-2(a) for the test year/post-test year periods.

A. The New Business category includes the costs of connecting new electric customers or upgrading existing services. This includes costs for meters, street and private area lighting, and the service connections for electric residential and smaller business customers, as well as the specific connection costs for large electric customer projects. Capital expenditures for new business are driven primarily by the number and type of new customers that PSE&G is required to serve. Test year and post-test year expenditures on Schedule PANEL-2(a) include the costs to serve new customers in the test year/post-test year period. Historically, large contributors to the capital plan include data centers, retail business expansions, as well as high-rise apartments and condominiums throughout the state. To illustrate the size and impact of data centers, in the past 10 years, PSE&G has invested $30 million in infrastructure to support data centers through 2022, with an additional ~$40 million for projects in the pipeline. Also, PSE&G has seen an increase in applications for electric vehicles in all customer categories, though for residential customers the requests are categorized as upgrades to existing service rather than new service. Businesses, on the other hand, often require new service as the requirements are large and may not be located near the existing service (e.g., electric vehicle charging station in far end of supermarket parking lot). Lastly, PSE&G has been monitoring other expected impacts to electric new business, including electrification of ports, transportation, fleets, and other large customer categories.

3. Environmental/Regulatory Category

Q. Please explain the costs reflected in the electric Environmental/Regulatory category for the test year/post-test year periods.

A. Expenditures in this category include the costs associated with non-discretionary relocation of facilities and miscellaneous projects needed to meet environmental or regulatory obligations. The greatest driver of the test year/post-test year expenditures within this category is the costs to relocate facilities to facilitate municipal construction projects. Other test year/post-test year expenditures within this category include the costs related to compliance with the Environmental Protection Agency's Spill Prevention, Control, and Countermeasure Program.

4. Facilities Support

Q. Please discuss the costs reflected in the electric Facilities Support category for the test year/post-test year periods.

A. Major expenditures included in this category on Schedule PANEL-2(a) are associated with support facilities such as buildings, vehicles, and similar miscellaneous expenditures. This category includes costs related to the replacement of the Company's vehicle fleet used to support electric distribution operations. The vehicles being replaced are at the end of their life cycle and cannot be cost effectively maintained. This category also reflects expenditures associated with the replacement of electric distribution radio equipment, which similarly has reached the end of its life cycle.

5. Energy Strong II (Electric)

Q. Please describe the Energy Strong II Electric Program.

A. The costs in this category are expenditures associated with Energy Strong II Program electric investments that will be placed in service during the test year and post-test year. In the Energy Strong II Order, the BPU authorized a second phase of PSE&G's Energy Strong Program to make further investments aimed at improving the reliability and resiliency of the Company's electric and gas systems by rebuilding and raising critical electrical equipment, installing stronger poles and wires, deploying advanced technology, building backup pipes, modernizing critical gas equipment, and improving customer service. The Energy Strong II Program has a four-year term, commencing on October 1, 2019, with work expected to conclude by December 31, 2023, subject to certain exceptions in the Board's Order. Under the Energy Strong II Program, PSE&G is authorized to make $641 million in electric capital investments, spread among the following sub-programs:

- $389 million for Electric Station Flood Mitigation, to mitigate storm risks at 16 identified electric stations;
- $145 million for Contingency Reconfiguration, to harden its electric distribution system and increase system resiliency by implementing contingency reconfiguration strategies;
- $72 million for Grid Modernization, Communications, which includes installation of a private wireless communications network and eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment; and
- $35 million for Grid Modernization, to replace the existing Outage Management System with an Advanced Distribution Management System ("ADMS") that will incorporate data from Geographic Information System and SCADA, intelligent fault indicators, Smart Meters, and other advanced metering infrastructure.

In addition, $100 million was also designated for stipulated base, which includes outside plant higher design and construction standards and/or electric life cycle subprogram project.

Q. Please describe the Energy Strong II Program electric investments in service and projected through the end of the Program.

A. For Energy Strong II the cost placed into service are shown in the table below:

Program Summary	Total Cost Placed in Service ($M)
Electric Stations Flood Mitigation	$ 336.1
Contingency Reconfiguration	$ 145.5
Grid Modernization, Communication	$ 63.6
Grid Modernization, ADMS	$ 17.4
Stipulated Base	$ 77.7
Total	**$ 640.3**

Stipulated Base	Total Spending Through Program
Total	$ 100.0

Q. Have any of these Energy Strong II capital investments been placed into rates?

A. The Energy Strong II Program approval Order permits the Company to file for rate adjustments to include Energy Strong II electric investments in the Company's rates.

Since the Company's previous base rate case, the Board has authorized four rate adjustments for Energy Strong II electric investments, which included capital investments of $447.1 million, or $456.9 million inclusive of allowance for funds used during construction. These investments were authorized by the Board to be included in base rates on a provisional basis subject to review in this rate case.[5]

The reasonableness and effectiveness of the costs underlying the rates implemented pursuant to these adjustments, as well as the success of the Energy Strong II Program, is supported by the findings contained in the Reports of the Energy Strong Independent Monitor that are attached as Schedule PANEL-4(a). In addition, the Company provides quarterly

[5] On November 1, 2023, PSE&G filed a fifth rate adjustment request under Docket No. ER23110784.

reports to Board Staff and Rate Counsel pursuant to the Energy Strong II Order that contains detailed information about Energy Strong II Program costs, ongoing reliability performance, and satisfaction of program goals. A copy of the most recent Energy Strong II quarterly report is attached as Schedule PANEL-4(b).

Q. Turning now to Energy Strong II Program expenditures that will be incurred during the test year, are these expenditures reflected on Schedule PANEL-2(a)?

A. Yes. Schedule PANEL-2(a) reflects Energy Strong II electric investments that will be undertaken during the test year. As explained by Company witness Mr. McFadden, PSE&G's filing in this case reflects certain ratemaking adjustments to ensure the Company does not double count the revenues associated with Energy Strong II investments that are expected to be captured in the rate adjustments expected to occur during the test year.

6. Infrastructure Advancement Program

Q. Please describe the Infrastructure Advancement Electric Program ("IAP").

A. The costs in this category are expenditures associated with IAP electric investments that will be placed in service during the test year and post-test year. The IAP was authorized by Board Order dated June 29, 2022, in BPU Docket Nos. EO21111211 and GO21111212 ("IAP Order"). The IAP Order authorizes the Company to invest up to $281.2 million in electric system upgrades to improve last mile reliability while supporting the electrification of the transportation sector and increased use of Distributed Energy Resources. The authorized IAP electric investments are split into two sub-programs:

- $91 million for the Electric Outside Plant Subprogram, including the Spacer Cable Conversion Project, the Lashed Cable Replacement Project, Electric Station Flood Mitigation, the Spacer Upgrade Project, the Conventional Underground Cable Replacement Project, and the Voltage Optimization Project; and

- $190.2 million for the Substation Modernization Program, which includes the 26kV Station Upgrade Project and the 4kV Substation Modernization Project to upgrade equipment at 5 stations. The IAP Order also requires the Company to spend a Stipulated Base of $160 million on certain capital projects to be recovered through base rates, $142.6 million of which shall be spent on electric system investments in specified categories.

Q. Have any IAP electric expenditures been reflected in rates?

A. There are currently no IAP electric expenditures included in the Company's rates. The Company filed for its first IAP rate adjustment on November 1, 2023 in BPU Docket No. ER23110783.

Q. Are any electric expenditures related to the IAP included in the test year or post-test year, as shown on Schedule PANEL-2(a)?

A. Schedule PANEL-2(a) reflects IAP electric investments that will be undertaken during the test year. As explained by Company witness Mr. McFadden, PSE&G's filing in this case reflects certain ratemaking adjustments to ensure the Company does not double count the revenues associated with IAP investments that are expected to be captured in the rate adjustments expected to occur during the test year and post-test year periods.

7. NJ Transit Mason Substation Replacement

Q. Please describe the Company's NJ Transit Mason Substation Replacement Project.

A. By Order dated November 21, 2017, the Board approved a plan to demolish facilities known as the Mason Substation, comprising a number of facilities and electric plant that at the time was owned by New Jersey Transit Corporation ("NJ Transit"), and to rebuild and modernize the facilities under PSE&G ownership. The substation, which is a crucial facility for both NJ Transit and northern New Jersey, suffered severe damage during Superstorm Sandy.

The cost of the rebuilt facility is shared between NJ Transit and PSE&G. The Board authorized PSE&G to recover its prudently incurred investment of up to $100 million plus an Allowance For Funds Used During Construction in a later base rate case. To date, $60 million of investment in the Mason Substation has been placed in-service, and the remaining $40 million will be placed in-service by November 30, 2024. PSE&G's final cost to complete the project will be $100 million. This cost was prudently incurred to enable PSE&G to continue to provide safe and reliable electric service in the northern New Jersey portion of its service territory. There is no question that the Mason Substation is necessary to support the electricity requirements of both NJ Transit and PSE&G and its other customers. Moreover, in proceeding with this Board-approved project PSE&G followed all of the practices and procedures I have described previously that ensure that PSE&G's share of the cost of this essential facility remained reasonable.

Q. What costs for the NJ Transit Mason Substation Replacement Project are being included in rates?

A. The Company has included in rates $100 million of costs prudently incurred to rebuild the structure. That figure includes costs that will be incurred in the post-test year period.

C. Gas Capital Expenditures

Q. Please describe PSE&G's gas capital spending since its last base rate case.

A. Since the Company's last gas distribution rate case it has invested a substantial amount of capital -- approximately $4.3 billion -- in new gas distribution plant through May 31, 2023. The majority of these investments were for the replacement of aging infrastructure and the hardening of the gas distribution system. As reflected on Schedule PANEL-2(b), the Company

projects that during the period June 1, 2023 through November 30, 2024, PSE&G will complete investments in new gas distribution plant totaling almost $1.7 billion. As with electric distribution, this level of gas distribution investment was and is required to maintain and enhance safe and reliable service to customers, support a continuation of our infrastructure investment efforts, and facilitate our ongoing commitment to provide excellent service to our customers.

Q. Please summarize the Company's test year and post-test year gas distribution capital expenditures set forth on Schedule PANEL-2(b).

A. As reflected on Schedule PANEL-2(b), the Company expects to incur gas system capital expenditures of approximately $1.1 billion during the test-year and approximately $0.6 billion in the post-test year in various spending categories that are described further below. In service test year investments amount to $1.1 billion and post-test year investments total $0.6 billion. The test year and known and measurable post-test year expenditures that will be placed in-service by November 30, 2024 are set forth in Mr. McFadden's testimony at Schedule MPM-7.

Q. What are the test year and post-test year gas capital expenditure categories reflected on Schedule PANEL-2(b)?

A. The test year/post-test year expenditure categories reflected on Schedule PANEL-2(b) include the major categories of gas investment described below:

1. Facilities Replacements

Q. Please describe the Facilities Replacements gas expenditures reflected on Schedule PANEL-2(b) for the test year and post-test year periods.

A. The Facilities Replacements category reflects expenditures associated with replacing defective or aging gas facilities. Test year and post-test year gas expenditures in this category include the replacement of approximately 73 miles of cast iron and unprotected steel mains, 10,200 services, 26 regulators, 223,000 gas meters and 6,000 house regulators. Mains and services replacements are prioritized in accordance with PSE&G's federally-mandated Distribution Integrity Management Program ("DIMP"), with the objective of enhancing safety by identifying and reducing gas distribution pipeline integrity risks. A pipeline integrity risk assessment is conducted as part of the DIMP and considers risk factors such as leak and break history, consequence of pipeline or pipeline component failure, operating and maintenance experience, and regulatory requirements. Expenditures in this category also include the replacement of certain metering and regulating equipment, and the replacement of certain pounds-to-pounds regulating station equipment. Notable projects in this category include the reconstruction of the Glen Rock pounds-to-pounds regulating station with a total projected cost of $19.5 million and replacement of a section of the Harrison lateral transmission line crossing multiple railroads with a total projected cost of $28.0 million.

2. System Reinforcements

Q. Please explain the System Reinforcement expenditures reflected on Schedule PANEL-2(b) for the test year and post-test year periods.

A. System Reinforcement expenditures are costs associated with increasing gas system capability to accommodate customers' peak demand and capacity requirements and for enhancing the system's ability to provide high levels of reliable service under adverse

conditions. Test year and post-test year gas expenditures in this category include the encapsulation of approximately 5,459 cast iron bell joints of various sizes, the installation of 23.7 miles of new gas mains and two new pounds-to-pounds regulating stations to reinforce system pressures, and the installation of cathodic protection devices, including testing stations, anodes and insulators on existing protected steel mains. Two major projects in this category are the Chatham System Reinforcement Project ("Chatham Project"), with a total projected cost of $19.7 million and the Haddon Township System Reinforcement Project ("Haddon Project") with a total projected cost of $15.7 million. The Chatham Project involves the conversion of the existing M&R station from a 15 PSI outlet pressure station to a 120 PSI outlet pressure station, the installation of approximately two miles of reinforcement main, and the installation of a new 120 PSI to 15 PSI pounds-to-pounds regulating station. This project enables the Company's Northern 15 PSI system to maintain adequate pressures at system low points in Springfield under design day demand conditions. The Haddon Project involves the installation of approximately two miles of reinforcement main and the installation of a new 60 PSI to 15 PSI pounds-to-pounds regulating station. This project enables the Company's Brooklawn-Camden 15 PSI system to maintain adequate pressures at system low points Haddon Heights, Barrington and Haddonfield under design day demand conditions.

3. New Business

Q. Please describe the gas New Business expenditures reflected on Schedule PANEL-2(b) for the test year and post-test year periods.

A. New Business expenditures are costs incurred to connect new gas customers or upgrade existing services. Capital expenditures for gas new business depend largely on the number and type of new gas customers that PSE&G is required to serve. The expenditures reflected on

Schedule PANEL-2(b) reflect the costs associated with service connections for new residential, commercial and industrial customers in the test year/post-test year period.

4. Environmental/Regulatory

Q. Please describe the Environmental/Regulatory gas expenditures reflected on Schedule PANEL-2(b) for the test year and post-test year periods.

A. Environmental/Regulatory expenditures are costs associated with projects needed to meet mandated environmental or regulatory obligations. Test year and post-test year gas expenditures in this category include various items related to environmental/regulatory compliance. Major test year expenditures in this category include the costs associated with service-cut-offs, as well as the costs related to unprotected steel service replacements as required by the *N.J.A.C.* 14:7-1.20, and main and service relocations due to municipal requirements. Test year/post-test year expenditures also include work involving pipeline replacement and construction to support ongoing integrity assessments in conformance with PSE&G's Gas Transmission Integrity Management Plan (or "TIMP") required under 49 CFR Part 192. Major projects within this category include multiple pipeline modifications to allow for integrity assessments utilizing robotic technology, to ensure compliance with 49 CFR Part 192.

5. Facilities Support

Q. Please describe the Facilities Support gas expenditures reflected on Schedule PANEL-2(b) through the end of the test year and post-test year periods.

A. Facilities Support expenditures are costs associated with support facilities such as buildings, vehicles, and similar miscellaneous expenditures. The projects included in the Facilities Support expenditures during this period include the relocation of the Oradell Gas District Headquarters due to ongoing flooding issues at the current location. This category also

includes necessary building improvements at the Company's twelve (12) Gas District Headquarters, the replacement of gas distribution fleet and radio equipment and security upgrades associated with Transportation Security Administration ("TSA") critical facility requirements. These security upgrades will take place, for example, at certain gas M&R stations and at transmission valve sites, where upgrades may include electronic access controls, security cameras, motion detectors, upgraded fencing and locking devices with patent keys.

6. Energy Strong II (Gas)

Q. Please describe the Energy Strong II Gas Program.

A. The Energy Strong II Order authorized the Company to make $50.5 million in gas system investments as part of the M&R Station Upgrades sub-program to rebuild/modernize M&R stations on the Company's gas system.

The Gas M&R Station Upgrade subprogram involved the modernization of the design of six (6) M&R stations to reduce the likelihood and consequence of equipment failure. The existing stations in the subprogram had an outdated design with upstream relief valves and single regulation runs. This arrangement can lead to a methane emission release through the relief valves in the event of a single regulator failure. The new design greatly reduces the likelihood of methane release. Additionally, the upgrades replaced aging facilities and hardened facilities located in the flood zones against severe flooding events. Two stations in the subprogram (Camden and East Rutherford) are in FEMA flood zones.

The project work under the Gas Metering & Regulating Upgrades subprogram commenced in the beginning of October 2019, with all the project works to be completed before the end of the test year. Under the Energy Strong II Accelerated Recovery Rate

Mechanism, up to $50.5 million was invested by the Company to rebuild and modernize the following M&R stations:

- Camden
- Central
- East Rutherford
- Mount Laurel
- Paramus
- Westampton

Any prudently incurred costs for work on the six M&R stations that exceeded $50.5 million has been credited toward the Company's stipulated base requirement, as authorized by the Energy Strong II Order.

Q. Please describe the Energy Strong II Program gas investments and projects placed in service through May 31, 2023, prior to the commencement of the test year.

A The Camden, East Rutherford and Westampton M&R station upgrade projects were placed into service prior to the test year. The upgrade work associated with these M&R stations included removal of existing PSE&G regulation and Remote Terminal Unit ("RTU") buildings and foundation, existing pipeline company regulators, and downstream piping. This work also included the installation of new buildings to house pressure regulation equipment, RTU functions, and, at Camden, a new boiler gas heating system. The Company also installed new yard piping from the point of ownership change to the new regulator and new RTU and associated equipment at the three sites. Series regulator runs designed as a working regulator

and a standby monitor regulator for on-site systems were installed at the three stations, along with downstream piping with new relief valves as a second line of overpressure protection. The scrubber, blowdown tank and associated piping connections, backup generator, and Monoethylene Glycol unit and associated piping connections at each facility were replaced, and the Company made upgrades to electrical and lighting systems and installed new security measures (*e.g.*, cameras, access control, door alarms). At the Camden and East Rutherford stations, PSE&G also elevated all buildings and sensitive equipment to a minimum of the FEMA 100-year flood elevation plus one foot (+ 1 ft) as part of the station upgrade. The Company also replaced existing water bath gas heaters at the Camden and East Rutherford stations.

Q. Have any of these Energy Strong capital investments been rolled into rates?

A. The Board has authorized two rate adjustments for Energy Strong II gas investments, which included capital investments of $50.5 million, or $51.9 million inclusive of allowance for funds used during construction, for Energy Strong II gas projects placed in service prior to the commencement of the test year. These investments were authorized by the Board to be included in base rates on a provisional basis subject to review and finalization in this rate case.

Like the Energy Strong electric distribution expenditures, the reasonableness and cost effectiveness of the gas distribution costs underlying the rates approved by the Rate Adjustment Orders, as well as the success of the Energy Strong Program, is supported by the findings in the Pegasus Reports attached as Schedule PANEL-4(a). As noted above, the Company also provides annual and quarterly reports to Board Staff and Rate Counsel pursuant to the Energy Strong Order that contains detailed information about Energy Strong program

costs, ongoing reliability performance, and satisfaction of program goals. A copy of the most recent Energy Strong quarterly report is attached as Schedule PANEL-4(b).

Q. Turning to the test year, does Schedule PANEL-2(b) reflect Energy Strong expenditures for this period?

A. Yes. The gas Energy Strong expenditures on Schedule PANEL-2(b) represent Energy Strong Program investments that the Company expects to undertake during the test year from June 1, 2023 to May 31, 2024.

7. GSMP I

Q. Please describe the Gas System Modernization Program I ("GSMP I").

A. GSMP is an accelerated infrastructure replacement program that was approved by a Board Order dated November 16, 2015 ("GSMP I Order"). The GSMP I Order authorized the Company to invest up to $905 million over three years to:

i. replace up to 510 miles of utilization pressure cast iron main ("UPCI") and unprotected steel main and services;

ii. uprate the UPCI system to higher pressure;

iii. install excess flow valves;

iv. abandon district regulators;

v. replace high pressure cast iron mains ("HPCI"); and

vi. recover the incremental cost of relocating inside meter sets outside.

Of the $905 million approved for GSMP, the Company was authorized to invest up to $650 million to be recovered by the Alternative Rate Mechanism. The GSMP Order required that PSE&G make base capital investments, referred to in the GSMP Order as "Stipulated Base," that are subject to two minimum investment criteria. The first criterion is that PSE&G

must spend a minimum of $85 million per calendar year from 2016 through 2018 on the types of plant specified to be part of Stipulated Base. The second requirement is that during the three years 2016 – 2018, PSE&G must install and place in service no less than a total of 110 miles of main to replace cast iron and unprotected steel mains and associated services under the Stipulated Base ("Stipulated Base Mileage and Stipulated Base Services").

Q. Please describe the Gas System Modernization Program II ("GSMP II").

A. GSMP II is the second phase of the Company's GSMP Program, which was approved by the Board in an order dated May 22, 2018 in BPU Docket No. GR17070776 ("GSMP II Order"). The GSMP II Order authorized the Company to invest up to $1.575 billion million over five years to: (a) replace UPCI mains and associated services and Unprotected Steel mains and associated services; (b) uprate the UPCI systems (including the uprating of associated protected steel and plastic mains and associated services) to higher pressures; and (c) install excess flow valves and eliminate district regulators, where applicable.

Under GSMP II PSE&G is required to make base capital investments, also referred to as a Stipulated Base. The Company must spend $300 million on certain capital projects during the five-year GSMP II, with no less than $20 million expended in each calendar year from 2019 through 2023, which shall be recovered through base rates.

Q. Has the Company met its Stipulated Base requirements under the GSMP I and II Orders?

A. Yes. In GSMP I the Company spent more than the stipulated requirement of $85M per year in each year with a total expenditure of $288.6 million. The Company has spent more than $20 million on stipulated base investments in each year of the GSMP II program with a total expenditure of $305.5 million.

Q. Are any of the GSMP I and GSMP II investments currently reflected in rates?

A. In the Company's previous base rate case, the Board found that PSE&G's GSMP I investments placed in service through September 30, 2017, were prudent and should be included in base rates. These investments were approved as prudent by the Board in the Company's 2018 rate case.

Since the last base rate case, the Board has approved two additional rate adjustment filings for GSMP I investments, consisting of $311.5 million in capital investments, and eight rate adjustment filings for GSMP II investments, consisting of $1.575 billion in capital investments. Pursuant to the Board's orders approving these filings, the revenue requirements associated with these investments have been included in the Company's rates on a provisional basis, subject to a prudency review in this proceeding.

Q. Can you summarize the Company's total GSMP I and II investments and Stipulated Base since the inception of the GSMP Program but prior to the commencement of the test year in this case?

A. The summary of the GSMP I&II Program and Stipulated Base investments are shown in the table below:

	2016	2017	2018	2019	2020	2021	2022	2023*
GSMP Investment ($M)	$159	$245	$201	$336	$407	$495	$353	$40
GSMP Miles Replaced	118	104	86	212	318	281	112	23
GSMP Services Replaced	6,808	9,858	9,963	14,655	18,222	27,324	20,462	1,331
Stipulated Base Investment ($M)	$95	$100	$94	$60	$46	$42	$128	$30
Stipulated Base Miles Replaced	71	29	42	23	22	26	63	12
Stipulated Base Services Replaced	3,180	2,494	3,241	1,393	1,107	932	4,678	1,092

* GSMP II was completed in Feb. 2023

Q. Turning to the test year expenditures, does Schedule PANEL-2(b) include Investments and Stipulated Base expenditures for the GSMP I and II?

A. Schedule PANEL-2(b) includes Investments and Stipulated Base expenditures for GSMP I and II.

Q. Are the costs underlying the rates approved by the Board, as well as all GSMP investments to date (including Stipulated Base spending), reasonable?

A. Yes. The GSMP investments were subject to the same PSE&G capital practices and policies described above that were favorably reviewed by Pegasus for the Energy Strong II Program. As we explained earlier, while the requirement to retain the independent monitor derives from the Energy Strong Order, the capital practices and processes reviewed by Pegasus apply uniformly to all capital spending, including GSMP investments. As noted above, the Company also provides monthly and quarterly reports to Board Staff and Rate Counsel in connection with GSMP I and II. Those reports contain information about GSMP costs and satisfaction of program goals, *i.e.,* leak reduction data. A copy of the most recent GSMP monthly report is attached as Schedule PANEL-4(c).

8. IAP (Gas)

Q. Please describe the Infrastructure Advancement Gas Program.

A The IAP Order authorized the Company to invest $69.8 million in gas system upgrades through the IAP, all of which are directed to the Gas M&R Station Modernization Subprogram. As noted above, the IAP Order requires the Company to invest a stipulated base of $160 million over the term of the program, $17.4 million of which must be used for specified gas investments.

Q. Have any IAP gas expenditures been placed into rates?

A. There are currently no IAP gas expenditures included in the Company's rates.

Q. Are any gas expenditures related to the IAP included in the test year or post-test year, as shown on Schedule PANEL-2(b)?

A. No. The first IAP projects are scheduled to be placed into service in December 2024, after the conclusion of the post-test year period in this proceeding.

IV. OPERATION AND MAINTENANCE EXPENSE

Q. Please provide an overview of your testimony regarding distribution-related O&M expense.

A My testimony addresses the level of electric and gas distribution-related O&M expense that PSE&G expects to incur in the test year, major expenses associated with operating the Company's electric and gas distribution systems, and the efforts taken by the Company to control distribution-related O&M expenses.

Q. What is the level of electric and gas distribution-related O&M expense that PSE&G expects to incur during the test year?

A. Total test year electric and gas distribution-related O&M expense is approximately $312 million. Of that amount, approximately $180 million is related to electric distribution operating costs and approximately $132 million is related to gas distribution operating costs. Electric and gas distribution O&M amounts are shown on Schedules PANEL-5(a) and PANEL-5(b), respectively.

A. Electric Distribution O&M

Q. Please discuss the types of expenses that comprise electric distribution O&M.

A. Electric distribution O&M expenses include the day-to-day activities of running the electric system that are critical to meeting the needs of our customers and maintaining the overall safety and reliability of the Company's electric distribution system. Electric distribution O&M work encompasses all of the extensive inspection and maintenance programs that are described in detail in PSE&G's Annual System Performance Report provided to the BPU. Major O&M activities include vegetation management (tree trimming); load checks on all underground transformers; storm restoration (which is discussed in more detail below); routine repairs, troubleshooting, and mark-outs of underground facilities; various inspections, including inspections of overhead lines, network protectors, critical plant inside substations, and various others types of facilities and equipment; meter and streetlight repairs; connecting and disconnecting active and inactive customers, shut-offs and restorations of customers; responding to police/fire emergency calls and customer complaints; maintaining customer accounts, billing and metering; and accounting, employee benefit management, and information technology. Also included in O&M are the costs of training the Company's workforce, which is a very critical area today given the turnover being experienced due to the retirement of experienced skilled workers and the significant hiring of new employees, many of whom are in apprenticeship classifications. For many job assignments or categories, it takes

up to two years of training and work experience before an apprentice or new employee is ready to be a fully qualified contributor.

Q. What are the key drivers of electric distribution O&M?

A. The major drivers of the test year electric distribution O&M budget are expenditures associated with (i) vegetation management, (ii) corrective maintenance, (iii) buildings and grounds, (iv) inspections, and (v) measurement cost. Test year expenditures for these major categories are set forth on Schedule PANEL-5(a). I discuss these major cost categories further below.

Q. Please discuss vegetation management costs.

A. Vegetation management costs have increased since the last rate case driven by significant labor inflation for this service. Vegetation management is performed when circuits are inspected and require maintenance per regulations discussed further below.

Q. What do the vegetation management regulations require?

A. In general, the regulations require that all circuits be inspected and, if necessary, that trees be trimmed at least once every four years. Consistent with the Board's regulations, all vegetation clearing work is performed in compliance with American National Standards Institute (ANSI) Z133.1 standard, which addresses arboriculture safety requirements for pruning, repairing, maintaining and removing trees and for using equipment in such operations; and with the A-300 standard, which addresses pruning and trimming operations, as well as all applicable OSHA requirements. Work related to vegetation management is performed by outside contractors with a small number of internal crews.

Q. Please discuss corrective maintenance costs.

A. Corrective maintenance is performed when facilities and/or equipment malfunction or otherwise do not perform at an optimal level. Maintenance intervention is required to return facilities and equipment to an operational, safe and reliable state.

Q. Please describe the costs associated with buildings and grounds.

A. Buildings and grounds costs involve the different activities associated with various structures (*e.g.,* office buildings, substation control houses) and associated property operated and maintained by the Company. Some typical costs include snow removal, weed control, repairs, janitorial services, utility bills and fire and building inspections.

Q. Please address inspections costs.

A. Inspection costs include inspections and related activities associated with PSE&G utility poles, underground lines, inside plant such as transformers breakers and relays, and other utility facilities. These activities are critical to help maintain the safety and reliability of the electric energy delivery system by identifying and eliminating defective facilities before failures can cause injury, damage, or unscheduled outages.

Q. Please address measurement costs.

A. Measurement costs involve expenditures for the many meter-related functions associated with 2.3 million electric meters located in PSE&G's service territory. These functions include activating and deactivating meters; reading meters; disconnecting and reconnecting meters; repairing and maintaining meter sets; and flood investigations at the meter. Please see testimony of Company witness David Johnson for additional details regarding the Company's Advanced Meter Infrastructure ("AMI") deployment.

B. Gas Distribution O&M

Q. Please discuss the types of activities within the gas distribution O&M budget.

A. PSE&G conducts extensive gas O&M activities, including finding and repairing gas leaks on mains, services and customer premises; responding to emergency leak situations; responding to gas pressure problems; conducting leak surveys; performing construction inspections and meter inspections; maintaining, monitoring and controlling gas pressures on the system; and maintaining customer accounts, billing, metering, and appliance safety for all customers. Most field operation activities are mandated by the U.S. Department of Transportation, including activities associated with pipeline integrity requirements for maintaining our gas transmission lines. Other activities, such as research and development participation, training and continuing education, accounting, employee benefit management, information technology, standards development, and participation in industry operations forums are in direct support of safe and effective gas distribution system operation.

Q. What are the key drivers of gas distribution O&M?

A. The biggest drivers of the gas distribution O&M budget are the costs associated with (i) safety, (ii) measurement, (iii) gas mark-outs, (iv) inspections and surveys, and (v) mains and services maintenance. Test year expenditures for these categories are shown on Schedule PANEL-5(b). I will address them in turn.

Q. Please address safety costs.

A. The safety category includes the costs associated with the first response to inside and outside gas leaks, meter and heater inspections, and initial appliance repair diagnostic work.

The costs associated with these activities are largely dependent on weather conditions and tend to be higher in periods where the temperature is colder than normal.

Q. Please address measurement costs.

A. Measurement costs involve expenditures for the many meter-related functions associated with almost 1.9 million gas meters located in PSE&G's service territory. These functions include activating and deactivating meters; reading meters; disconnecting and reconnecting meters; meter inspections, repairing and maintaining meter sets; and flood investigations at the meter.

Q. Please address gas mark-outs.

A. The State of New Jersey requires that the location of underground utility installations be identified and marked out prior to work that involves any digging operation. Activities covered by this requirement include excavations or trenching, blasting, installation of tents, sign posts, or fence posts, and removing or planting of trees. Expenditures in this category have been trending upward since PSE&G's last base rate case largely because of an increase in the number of mark-outs, as well as an increase in costs of 2.8% per year (2019 – 2022) due to wage increases. For example, in 2022 mark-out costs were approximately $18.5 million compared to costs of approximately $17 million in 2019 and projected test year expenditures of over $9.4 million.

Q. Please discuss inspections and surveys costs.

A. Expenditures in this category relate to the wide variety of surveys and inspections conducted on over 35,600 miles of gas mains and services and almost 1.9 million gas meters in PSE&G's service territory. Expenditures here include the costs associated with patrols,

inspections, and surveys to check and maintain the safety, reliability, and operational soundness of the Company's facilities, including mains, services, and inside and outside meters.

Q. Please address mains and services maintenance costs.

A. These costs include all maintenance of and repairs to mains, services, regulators, and cathodic protection of protected steel mains. Ongoing maintenance and repairs are needed to maintain the safety and reliability of the gas distribution system.

C. Electric and Gas Distribution O&M Cost Control Efforts

Q. Please describe some of the efforts taken by the Company to manage electric and gas distribution O&M costs.

A. Since the Company's last electric and gas base rate cases, various steps have been taken to help manage the Company's electric and gas distribution operating costs. While these costs relate to essential functions that are required to operate and maintain the electric and gas distribution systems, the Company continues to look for ways to maximize efficiencies and control operating costs.

As mentioned previously, the Company is aggressively replacing cast iron and unprotected steel gas main and services through its GSMP program. One of the many benefits of the GSMP accelerated replacement is the reduction in the number of leaks associated with leak prone pipes, which supports the control of O&M costs associated with leak response and management. Since the last rate case, the Company has experienced a downward trend in open leaks, cast iron main breaks, leak repairs, and leak repairs per mile.

The Company continually focuses on identification and implementation of efficient processes and technological improvements to control O&M costs.

For example, the Company has replaced obsolete paper chart pressure recorders at natural gas district regulator stations with electronic pressure recording devices. Every low pressure distribution system that is supplied by more than one district regulator is required to have at least one pressure recording device. The use of electronic pressure recording devices eliminates the costs associated with paper chart retrieval and maintenance. Electronic pressure recorders also have the added benefit of providing real-time alarms that can be sent to a computer or phone, as well as access to the data by multiple users through a secure online portal.

The Company sought to increase efficiency when conducting required leak detection surveys through the use of new technology solutions. The implementation and use of remote methane leak detectors ("RMLD") effectively reduces the time required for service leak detection surveys, and improves survey efficiency. The Company's Gas Appliance Services also implemented a new software to manage Appliance Service work orders. The software has the capability to automatically dispatch work orders to Appliance Service Field Technicians, significantly improving efficiency by reducing travel time and costs to customers' premises.

Additionally, in an effort to reduce costs associated with training entry level apprentices and employees, the Company effectively negotiated with the unions to modify time-in position lock-in periods. Various entry-level Bargaining Unit positions now have a five-year lock-in period, ensuring that personnel do not transfer to another position within the Company in the first five years of employment. This new lock-in requirement has reduced the amount of training required for these positions, thus reducing the associated training costs.

Other savings initiatives that the Company has implemented include:

- Increased supplier pool and multi-year contracts for vegetation management;
- Optimized vehicle maintenance schedules;
- Enhanced training opportunities including e-learning curriculum;
- Reevaluation and optimization of Administrative staff;
- Minimized travel expenses for only essential/critical business meetings;
- Reevaluated and adjusted shift timing to reduce overtime;
- Instituted our Tech talk program reducing travel time and costs associated with appliance repair; and
- Re-evaluated facilities' needs to reduce unnecessary maintenance costs.

D. Storm Restoration Costs

Q. You mentioned earlier that costs associated with storm restoration are among the major O&M costs incurred by the Company; could you briefly explain what types of costs are included as "storm restoration costs"?

A. Storm restoration costs are the incremental labor, material, outside contractor, and other costs incurred by the Company to safely and efficiently restore customer's electric and gas service as quickly as possible after an interruption due to a Major Event, including but not limited to costs associated with extraordinary internal labor deployment, mutual aid contractors, tree trimming contractors, staging areas, pole fixtures, meals and lodging for restoration personnel, and communications with customers, emergency personnel and local authorities.

Q. How does the Company currently recover storm restoration costs in rates?

A. The prior rate case included a new regulatory asset consisting of the deferred incremental O&M storm costs incurred prior to and during the test year. These prior incurred storm costs are currently being recovered in rates. The Company is not recovering any deferred incremental storm costs incurred since the prior base rate case. The capital storm costs are included in net plant from the prior rate case.

Q. How does the Company ensure that its storm restoration costs are reasonable?

A. During the storm preparation phase, an analysis of the storm severity level and required staffing requirements is completed, and the optimized restoration resources are procured. Additionally, the restoration effort is closely monitored by senior leadership through multiple daily conference calls and real time operations data. These calls, coupled with real time restoration data, enable the efficient deployment of both internal and external resources to ensure that customers are restored in the safest, quickest and most cost effective manner possible.

Q. Do the Company's books and records contain a regulatory asset for storm restoration costs incurred since the Company's previous rate case?

A. Yes, the Company's books and records contain $105.1 million for electric and $3.7 million for gas in a regulatory asset for incremental O&M costs related to Major Storm Event restoration. From 2019-2021 a total of five storms occurred, two of which were named storms known as Tropical Storm Isaias ($72 million O&M cost for electric) and Hurricane Ida ($8 million O&M cost for electric and gas). The other three storms were the February 2021 Snow Storms, the June 2020 Derecho, and the July 2019 Major Storm.

Q. Please explain why you believe that those deferred storm restoration costs were reasonably incurred to provide safe and reliable service to customers.

A. PSE&G has a robust and disciplined approach to storm restoration which enables the Company to restore customers in a safe, efficient and timely manner after unpredictable and widespread severe weather event damage. This storm restoration approach and the Company's spending in support thereof has been reviewed by the Board and found to be prudent in the Board's September 30, 2014 order in BPU Docket Nos. AX13030196 and EO13070607. The incremental O&M costs we are now seeking recovery for was spent in a similar disciplined and efficient manner with the sole purpose of restoring our electric and gas customer's service as safely and quickly as possible.

Q. Is the Company proposing to modify the way it recovers storm restoration costs in the rates established in this proceeding?

A. Yes. As discussed by Company witnesses Mr. McFadden and Mr. Swetz, the use of deferred accounting coupled with an annual surcharge mechanism is the most appropriate means of recovering Major Storm event costs by protecting the Company from significant financial harm from major weather events outside its control as well as ensuring that customers only pay for actual prudently incurred costs.

Q. Why is the Company proposing to change the way it recovers storm restoration costs?

A. Adoption of a Major Storm Events cost recovery mechanism as proposed by the Company would allow for a prudence review of the deferrals and cost recovery within a reasonable time after they are incurred instead of reviewing all Major Storm Events that occur between rate cases at the same time. These interim rate proceedings will help the Company maintain its credit ratings as noted above (which have benefited customers) as well as prevent

any rate shock to customers that could arise if the Company were permitted to recover the costs of all post-test year events at the same time. Finally, the use of a surcharge provides a mechanism to stop the amortization when recovery of the deferral is completed. As a result, the Company is proposing that a new clause, "the Storm Recovery Charge" be created to recover the $109 million in deferred storm costs increased since the last rate case as well as any future prudently incurred storm costs. For more details concerning the new clause, please see the testimony of Company witness Stephen Swetz.

Q. Are you proposing any other change to the manner in which costs associated with major storm events are recovered from customers?

A. Yes. Based upon the severity of weather forecasts, the Company sometimes prepares in advance for a storm by procuring and/or mobilizing contractor crews prior to the onset of adverse weather with the intention of deploying those crews to shorten the duration of customer interruptions. If the actual weather does not end up meeting the definition of a "major storm" the Company should nonetheless be provided an opportunity to recover prudently incurred "pre-staging costs" incurred to respond to potential storms. The Company proposes that under the Major Storm Events cost recovery clause that it is proposing it should be permitted to include recovery of pre-staging costs that exceed, in any instance, $250,000. Permitting the deferral and recovery of such pre-staging costs will encourage the Company to prudently prepare for future storms to the benefit of all its customers.

Q. Why does the Company believe that it is reasonable for the Company to recover pre-staging costs through its proposed storm restoration clause?

A. PSE&G's first priority is providing safe, efficient and reliable service to its customers. This commitment is tested during severe weather events, where efforts to ensure timely

restoration of service begin well before the first signs of severe weather enter our territory. In an effort to minimize delays in restoration, the Company must secure staging areas, materials, and mutual aid/contractor resources early on in the process, many times prior to any reported outages, depending on the severity of the weather forecast. This preparation is a critical step in the restoration process, and is undertaken in good faith that the reasonable expenses incurred will be recovered in the future.

V. APPLIANCE SERVICE BUSINESS

Q. Please describe PSE&G's Appliance Service Business ("ASB").

A. PSE&G has been providing appliance service since the 1920s, when the Company sold and serviced its own appliances and certified other appliances as safe. These services are currently offered as competitive services for customers in PSE&G's service territory in accordance with a tariff filed with the Board of Public Utilities ("Board"). These services include (a) Appliance Repair Service, (b) Maintenance Services, (c) Replacement Parts Service Contracts, (d) Water Heater replacement Service, and Central Heater and Central Air Conditioning ("HVAC") Replacement. The majority of the existing program work is performed utilizing PSE&G's workforce with the exception of the water heating replacement work, which is performed by contractors retained by the Company.

Q. Does PSE&G's ASB function only provide competitive services?

A. No. The majority of the work performed by the ASB function unit is non-competitive work that is part of PSE&G's regulated gas utility business. The bulk of regulated work performed by the ASB group involves emergency response (*e.g.*, responding to calls from customers about gas leaks and pilot odors) and gas appliance adjustment services. Technicians

also perform meter services (e.g., meter installations and replacements and turn on and shutoff services). These non-competitive services are an intrinsic part of PSE&G's traditional utility business of distributing natural gas. There are no charges for customer requested regulated services, except for heating "turn on" charges and off cycle inspections.

Q. What competitive services does PSE&G offer to customers through its Appliance Repair Service and Maintenance Services businesses?

A. The Appliance Repair Service and Maintenance Services, also known as PSE&G's "APSO" product line, are core services for the Company and align with the Company's reputation as a safe, trusted and reliable provider of gas service. The APSO product lines covers, repair and the replacement of defective parts on specified appliances for residential and small industrial and commercial customers. Appliances covered by the APSO line include furnaces and boilers, central air conditioning, ductless mini-split heating and cooling equipment, water heaters, refrigerators, stoves, wall ovens, electric freezers, dishwashers, washers, dryers, pool heaters, gas grills, and gas fireplaces. APSO service work is performed by highly skilled PSE&G service technicians. APSO services are billed separately for each repair to customers utilizing the service based on a predetermined pricing schedule.

Q. Please describe the Replacement Parts Service Contracts product line offered by PSE&G.

A. Appliance-parts contracts, commonly known as WorryFree® Replacement Parts Service Contracts, generally cover the cost of the repair and replacement of specified parts on the appliances, including central house heating equipment, water heaters, electric central air conditioners, kitchen and laundry equipment, gas piping, gas fireplaces, rooftop heating equipment, electric rooftop and central air conditioners. WorryFree® service also includes,

where appropriate, the cost of labor, materials, and diagnostic time. PSE&G offers repair contracts and parts replacement through the WorryFree® program but does not sell new appliances at this time.

As with all competitive services, participation in the WorryFree® Replacement Parts Service Contract program is optional. Customers who utilize the WorryFree® Replacement Parts Service Contract program are billed for the service on their PSE&G Utility monthly statements.

Q. Please describe the Water Heater and HVAC Replacement Service product line.

A. The Water Heater and HVAC Replacement Service product line provides customers with reliable, premium replacement services for water heaters, central house heating, electric central air conditioning, and heat pumps. Through this program, PSE&G customers are able to select equipment that matches their requirements and have that equipment installed.

Q. How are the costs and revenues associated with the ASB reflected in the Company's electric and gas rates?

A. ASB net margin revenues are accounted for and allocated in accordance with N.J.A.C. 14:3-3.6(r). Under this regulation, total gas margin from ASB revenues is treated above-the-line for rate-making purposes and is credited to customers. For electric ASB revenues, however, the regulation dictates that 50 percent of the total margins be recorded in competitive service revenue accounts and included above-the-line for ratemaking purposes and credited to customers. The remaining 50 percent of electric ASB margins may be recorded below-the-line and retained by the Company.

The revenues and expenses associated with the appliance service business are included in the income statement for the utility, specifically in the gas business. As a result, the net

above-the-line margin (revenue less expenses) from operating the appliance service business is credited to customers in base rates. In this current base rate case proceeding, the Company proposes $46 million in ASB margin to directly offset the Company's revenue requirement to the benefit of customers.

Q. Do any other utility companies in New Jersey maintain ASBs?

A. No. All other utility companies in New Jersey have ceased to provide competitive ASB products and services. As such, PSE&G's ASB, and the associated ASB revenues included in the Company's revenue requirement are a unique benefit that PSE&G provides to its customers.

Q. Is ASB a growing business for the Company?

A. No. Although the Company provides appliance services to a significant number of customers, since 2020, virtually all of the Company's ASB products and services have experienced negative growth in terms of number of customers. In other words, the ASB market is saturated. At the same time, the Company's costs of providing the service have consistently increased due to largely unavoidable increases in cost items such as employee wages, benefits, and increases in material costs.

Q. Is the Company proposing to change the way ASB revenues are treated for ratemaking purposes?

A. Yes. The Company proposes that the Board grant a waiver of *N.J.A.C.* 14:4-3.6(r)(4) such that PSE&G is permitted to retain 50% of the total net margins associated with both gas and electric ASB services.

Q. Why does the Company believe that this change is appropriate?

A. The Company believes this change is appropriate for several reasons. First, the ability to retain a portion of margin revenues related to gas ASB products will provide a strong incentive to continue to provide ASB services, to continue to seek and implement efficiencies in the ASB business, and to seek opportunities for growth of the ASB business in an increasingly challenging marketplace.

Q. How will this change benefit customers?

A. This change will benefit customers because it will allow the Company to continue to its ASB business and, as a result, customers will continue to benefit from ASB margin revenues being reflected in the Company's rates as well as from the Company's continued presence as an ASB provider. As noted above, the inclusion of ASB revenues in rates is a unique benefit in the State for PSE&G customers. PSE&G believes the proposed adjustment will allow the Company to justify remaining in the ASB in an increasingly challenging marketplace.

Q. Please explain the challenges that the Company's ASB is facing.

A. The Company is grappling with external factors that have reshaped the appliance industry, resulting in declining or stagnant performance for ASB program revenues. Manufacturers for many appliances have begun emphasizing replacement of old or underperforming appliances with new equipment, rather than maintenance and repairs of existing appliances. This, in turn, has shifted consumer habits, creating a surge in demand for new appliances from manufacturers while slowing or reducing demand for the Company's ASB services. Warranties for these new appliances, as well as service programs offered by manufacturers, have further impacted PSE&G's ASB revenues.

In addition, cost inflation has negatively impacted ASB contract margin. Cost for replacement parts has increased in recent years, resulting in PSE&G raising contract prices to mitigate negative margin impacts. A strategy of regular price increases can drive higher levels of contract cancellations, eventually leading to declining margins.

Other macroeconomic and regulatory forces have also impacted the Company's ASB revenues. Homeownership in New Jersey has decreased from 69% in 2006 to 64% in 2022, resulting in a reduction of approximately 28,000 homeowners in PSE&G's service territory. This has impacted the number of potential customers for the ASB programs as homeowners are more likely to purchase ASB services. Additionally, the Company has been focused on reducing uncollectible account receivables since 2010 and has determined that it will not provide ASB services to customers with outstanding uncollectable balances in an effort to encourage collections.

The shift in economic factors and consumer habits present significant challenges to PSE&G's ASB business. If unaddressed, these factors pose a notable threat to the continued economic viability of the ASB programs, and the ASB revenues used for the benefit of customers.

Q, Has PSE&G made any effort to address the challenges faced by the ASB programs?

A. Yes. In an effort to maintain the revenue margins for the ASB programs, PSE&G has increased prices for ASB programs. Although these increases have helped to maintain revenue margins from the ASB businesses, this approach is not sustainable because higher prices

incentivize customers to opt for new appliance replacements instead of repairs, exacerbating the decline in customer contracts.

Q. Is the Company considering any other modifications to its ASB offerings?

A. Yes. The Company is considering expanding its ASB offerings to include new technologies and services, including but not limited to internal and external home electric system protection plans, home energy audits, home weatherization services, and electric vehicle ("EV") charger installation and servicing. In the event that the Company determines to move forward with any new ASB services, it will comply with all regulatory requirements applicable to such services including, if necessary, filing a petition with the BPU for authority to offer such services. These new products and services may provide the Company the opportunity to generate additional ASB revenues to justify the continued existence of the program.

Q. What is the potential effect of continuing the status quo with respect to the Company's ASB?

A. The current economics of the ASB impose considerable risks on the Company with prospects for limited improvement. Although the Company would like to maintain its ASB services, the Company cannot continue to engage in a line of business that is not economic. The closure of the ASB business would hurt both the Company's customers, through the loss of ASB margin revenues and the availability of ASB services, and the State's economy, through the loss of jobs provided by the ASB business. The Company believes that the changes discussed here will provide the ASB with the additional needed support to continue the business.

Q. Does this conclude your testimony?

A. Yes, it does.

Qualifications of Michael A. Schmid
Vice President – Asset Management and Planning

I am Vice President of Asset Management and Planning for Public Service Electric and Gas Company ("PSE&G" or the "Company"). With over thirty years of experience in gas delivery and electric operations at PSE&G, I have developed a broad set of managerial, leadership, strategic, analytical and engineering skills.

I began my career at PSE&G in 1991 as an associate engineer in the Company's Trenton Gas division. I was promoted over the following years to a series of engineering positions with increasing levels of responsibility and in 1997 was promoted to the position of Operations Engineer-Integrated Services, with supervisory responsibilities for several Electric and Gas employees maintaining and improving the Distribution work management system (AWMS). In 1998 I was promoted to Distribution Business System Leader-Client Services, and from that time through November 2010 continued to broaden my knowledge of and responsibility for PSE&G's Electric and Gas Distribution System as Asset Strategy Leader-Asset Management, Operations and Resource Manager - Gas Delivery, and Division Manager - Gas Delivery. Some examples of my responsibilities and accomplishments in those roles included management of the Electric and Gas Distribution Business Systems department, including the development and implementation of Distribution's IT strategic vision; development and implementation of the Gas Distribution Asset Strategy and conversion of that strategy into annual prioritized work plans; management of the planning and design of PSE&G's system for load growth and reinforcement; development and management of the utility's capital and O&M work plans and financial plans; management of division-wide industrial relations matters; and responsibility for the appliance service business, gas

construction, operations and maintenance for approximately 600,000 gas customers covering a service territory of approximately 600 square miles.

In November 2010 I was promoted to Director of Appliance Service Field Operations/Gas Construction- Gas Delivery. In that position I provided leadership, strategic direction, and overall accountability for employees and contractors, and financial and material resources to safely deliver state-wide gas energy and appliance services to customers. In 2017 I became Electric Division Manager- Electric Operations, and provided strategy, leadership and direction over all departments within Electric Operations, with responsibility for customer satisfaction of approximately 500,000 customers, safety of approximately 500 employees, and ensuring diversity and inclusion for all employees within the division.

In 2019 I was promoted to Vice President, first of Asset Management and Centralized Services and then in 2021 of Asset Management and Planning, which is my current position. In these positions I have, among other things, provided management oversight and directed the resources and activities related to the overall management of PSE&G's electric and gas delivery assets and system performance and reliability; performed wholesale/retail energy supplier service management and basic generation service (BGS), basic gas supply service (BGSS), and NUG contract management; and managed key utility-wide processes including new business, street lights, interconnections, traffic control, utility capital project governance, specific SOx compliance areas and utility level self assessments.

I have a Bachelor of Science degree in civil Engineering from Rutgers University, an MBA in Management of Technology from NJIT, and I am a Professional Engineer.

Qualifications of Ricardo Fonseca
Senior Director – Utility Finance

I currently hold the position of Senior Director of Utility Finance for Public Service Electric and Gas Company ("PSE&G" or the "Company") and have worked for the Company in several capacities over the course of 26 years. My career with PSE&G began in September 1997 working as a Call Center Collector. In 2000, I joined the accounting department and worked as a vendor liaison for our accounts payable department. In 2002, I was promoted to the position of financial analyst in the Company's Sales and Revenue forecasting department where I provided support for PSE&G's economic forecasting model and developed an understanding of the tariff and billing determinants.

In 2004, I was promoted to a business analyst in the Long-Term Financial Planning Department with the responsibility to support all phases of the long-term plan for the Utility. I was responsible for developing the overall 5-year financial plan including Capital and O&M budgets for the Company.

In 2008, I was promoted to the position of Manager of Utility Business Strategy and Finance overseeing a team of analysts and given the responsibility for leading and developing the Utility business plan and strategic outlook. As manager of this team, I was also responsible for assisting in the development of financial statements supporting regulatory filings and the development of external financial presentations.

In August 2011, I was promoted to the Director of Sales and Revenue Forecasting where I was responsible for the Electric and Gas customer, Sales and revenues forecasts and long-range plan. I also determined and estimated the main factors impacting customer and sales projections and the resulting revenue projections and provided billing determinants for

various regulatory filings including the weather normalization clause filing.

In October 2014, I was promoted to the role of Director of PSE&G Finance with overall responsibility for all financial planning and forecasting activities for the Utility. Specifically, I developed long-range and short-term financial forecasts, determined the Company's capital and O&M budgets, ensured strict adherence to PSE&G's capital governance requirements, and was responsible for the annual filing of the Transmission formula rate.

In June 2021, I was promoted to the role of Senior Director of Utility Investment Planning, Business Improvement and Processes. In this role, I ensured the Utility was executing on its capital plan and provided strategic guidance on investment planning. I was also responsible for the Street Lighting, Traffic control and the third-party attachments processes.

In July 2022, I assumed my current position, which has overall responsibility for long-term and short-term financial planning, capital governance, and investment planning. I am also responsible for providing strategic financial guidance, the Transmission formula rate process, and the sales and revenue forecasting process.

Test Year / Post Test Year Electric Capital Expenditures

in $000

Schedule - PANEL-2(a)

		Test Year Total June 2023 - May 2024	Post Test Year Total June 2024 - Nov 2024
Facilities Replacements	$	261,252	$ 124,917
System Reinforcements	$	277,649	$ 142,761
New Business	$	164,188	$ 76,492
Environmental/Regulatory	$	15,406	$ 5,540
Facilities Support	$	143,039	$ 53,364
Energy Strong	$	146,087	$ 11,510
IAP	$	146,327	$ 78,280
AMI	$	261,013	$ 81,817
Total	**$**	**1,414,960**	**$ 574,681**

Test Year / Post Test Year Gas Capital Expenditures

in $000

Schedule - PANEL-2(b)

		Test Year Total June 2023 - May 2024	Post Test Year Total June 2024 - Nov 2024
Facilities Replacements	$	682,287	$ 138,011
System Reinforcements	$	147,881	$ 44,931
New Business	$	102,167	$ 52,719
Environmental/Regulatory	$	31,995	$ 16,480
Facilities Support	$	88,331	$ 61,348
Energy Strong II	$	34,333	$ 4,057
IAP	$	14,402	$ 21,465
GSMP II Extension	$	11,250	$ 280,630
Total	**$**	**1,112,646**	**$ 619,641**

Matthew M. Weissman
General State Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel: 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

August 19, 2019

Via Electronic Mail & Regular Mail

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
SEVERE WEATHER EVENTS
JULY 17 - 25, 2019

Dear Director Giuliano:

As required by 14:5-8.9, enclosed is a copy of PSE&G's Major Event Report for the severe weather events from July 17 - 25, 2019.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner

PSE&G's REPORT TO THE BPU
MAJOR EVENT
SEVERE WEATHER EVENTS
JULY 17 - 25, 2019

EXECUTIVE SUMMARY

During the period of July 17-25, 2019, PSE&G's service territory was affected by three separate weather events. During the afternoon on July 17th, severe thunderstorms affected the entire service territory with Southern Division experiencing the most damage and the most outages. Beginning on July 20th, extreme heat was experienced in all four operating divisions. High temperatures were in the 95–100 degree F range with heat indices of 105–110 degrees F. The extreme heat ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory. Once again, Southern Division was hit the hardest with extensive plant damage and the most outages. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties.

As discussed with Board staff on July 23rd because of the severity of these weather events, they will be considered as one Major Event. These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more that 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company, were interrupted and each of PSE&G's other three operating divisions supplied line and service repair crews to Southern Division.

SEVERE THUNDERSTORMS - JULY 17–19, 2019

EXECUTIVE SUMMARY

During the afternoon on July 17th, severe thunderstorms affected the entire service territory with Southern Division experiencing the most damage and the most outages. Based upon weather forecasts, during that morning's 0800 hrs. daily operations conference call, a 1300 hrs. conference call was scheduled to review storm preparation plans. During that conference call, line crews, support personnel and tree crews in each of PSE&G's four operating divisions were held over to work the 1500 - 2300 hrs. shift. In addition, these divisions placed line crews, support personnel and tree crews on stand-by.

As a result of the plant damage and outages in Southern Division, a staffing conference call was scheduled for 0630 hrs. on July 18th. During that call, PSE&G assigned 48 line crews and support personnel that morning from the other three divisions, Projects and Construction (P&C) and from a contractor that was on PSE&G's property to Southern Division to assist in service restoration. Central Division also supplied a line crew to Southern Division at 2300 hrs. on July 17th.

Beginning at 0800 hrs. on July 18th, PSE&G held multiple conference calls concerning storm restoration efforts until July 19th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C, the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the company.

Communications with Board staff concerning this weather event began on July 18th and continued until July 19th.

PSE&G opened its Utility Emergency Operations Center (UEOC) from 0600 - 1700 hrs. on July 18th and from 0700 - 1700 hrs. on July 19th.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	15,940	July 19th - 0300 hrs.
Metropolitan	2,493	July 18th - 1853 hrs.
Palisades	7,020	July 18th - 2000 hrs.
Southern	51,933	July 19th - 1115 hrs.
Total	77,386	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

During the afternoon on July 17th, severe thunderstorms affected the entire service territory with Southern Division experiencing the most damage and the most outages. Based upon weather forecasts, during that morning's 0800 hrs. daily operations conference call, a 1300 hrs. conference call was scheduled to review storm preparation plans. During that conference call, line crews, support personnel and tree crews in each of PSE&G's four operating divisions were held over to work the 1500 - 2300 hrs. shift. In addition, these divisions placed line crews, support personnel and tree crews on stand-by.

As a result of the plant damage and outages in Southern Division a staffing conference call was scheduled for 0630 hrs. on July 18th. During that call, PSE&G assigned 48 line crews and support personnel that morning from the other three divisions, Projects and Construction (P&C) and from a contractor that was on PSE&G's property to Southern Division to assist in service restoration. Central Division also supplied a line crew to Southern Division at 2300 hrs. on July 17th.

Beginning at 0800 hrs. on July 18th, PSE&G held multiple conference calls concerning storm restoration efforts until July 19th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs which encompass all three weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division.
Attachment "L" - Overhead Line Crews and Service Repair Crews Assisting Central Division
Attachment "M" - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division.
Attachment "N" - PSE&G Contractor Line Crews Assisting Southern Division
Attachment "O" - Mutual Aid FTEs Assisting Southern Division

A liaison was assigned to Southern Division from 0700 hrs. to 1930 hrs. on July 18th and from 0730 hrs. to 1100 hrs. on July 19th to assist in addressing customer inquiries.

All 11 Offices of Emergency Management (IEM) were contacted. Burlington and Camden County Offices opened but did not require a PSE&G representative on site. The PSE&G representatives provided remote support.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	- 16
13 & 4-kV	- 210
Transformers	- 38
Secondaries	- 30
Services	- 90
Poles	- 32
Trees	- 136
Total	- 552

INCIDENTS

The Ewing Community Center, 999 Lower Ferry Road, Ewing became a gathering point for residents who had their electric service interrupted by the storm. On July 18th, PSE&G supplied water, ice and customer services to the Center. The customer services included providing ETR updates to customers and issuing service orders if needed.

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 18th and continued until July 19th.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media posts to particularly hard hit communities provided support information including the location of cooling stations.

HEAT STORM – JULY 20-22, 2019

EXECUTIVE SUMMARY

Immediately following the July 17th severe thunderstorms weather event, PSE&G's entire service territory was subjected to a heat storm beginning on July 20th. High temperatures were in the 95-100 degree F range with heat indices of 105-110 degrees F. The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory.

On July 18th in anticipation of the heat storm, Board staff requested that the EDC's, "report any outages affecting multi-unit-at-risk population buildings (hospitals, nursing homes, assisted living centers, senior living complexes, etc.) to the BPU as soon as you become aware of the outage." PSE&G made arrangements that day to adhere to that request.

Beginning at 1100 hrs. on July 20th, PSE&G held multiple conference calls concerning the heat storm until July 22nd. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company.

Communications with Board staff concerning this weather event began on July 18th and continued until July 22nd.

PSE&G did not have to open its UEOC for this weather event.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	26,288	July 23rd – 0500 hrs.
Metropolitan	7,199	July 22nd – 1811 hrs.
Palisades	7,800	July 22nd – 1615 hrs.
Southern	15,015	July 22nd – 1655 hrs.
Total	56,302	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

Immediately following the July 17th severe thunderstorms weather event, PSE&G's entire service territory was subjected to a heat storm beginning on July 20th. High temperatures were in the 95-100 degree F range with heat indices of 105-110 degrees F. The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory.

On July 18th in anticipation of the heat storm, Board staff requested that the EDC's, "report any outages affecting multi-unit-at-risk population buildings (hospitals, nursing homes, assisted living centers, senior living complexes, etc.) to the BPU as soon as you become aware of the outage." PSE&G made arrangements that day to adhere to that request.

Beginning at 1100 hrs. on July 20th, PSE&G held multiple conference calls concerning the heat storm until July 22nd. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company.

On July 21st, PSEG had a new Sunday system peak of 9,540 MW.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs which encompass all three weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division
Attachment "L" - Overhead Line Crews and Service Repair Crews Assisting Central Division
Attachment "M" - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
Attachment "N" - PSE&G Contractor Line Crews Assisting Southern Division
Attachment "O" - Mutual Aid FTEs Assisting Southern Division

It was not necessary for PSE&G to assign liasions to the operating divisions or to the Inquiry Centers during this weather event. It was also not necessary to contact any of the 11 County Offices of Emergency Management.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	11
13 & 4-kV	-	137
Transformers	-	155
Secondaries	-	8
Services	-	30
Poles	-	20
Trees	-	32
Total	-	393

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 18th and continued until July 22nd.

PSE&G's Corporate Communications Department responded to several television and radio information requests during this period. In addition, social media posts were monitored.

VERY SEVERE THUNDERSTORMS – JULY 22-25, 2019

EXECUTIVE SUMMARY

The heat storm ended on the afternoon of July 22nd when very severe thunderstorms crossed the entire service territory. Once again, Southern Division was the hardest hit with extensive plant damage and the most outages.

During the 0800 hrs. operations conference call on July 22nd, Central Division reported that they still had over 1,300 customers out of service from the thunderstorms that hit their service area during the early evening on July 21st. As a result, Southern Division sent five line crews, two service repair crews and support personnel to Central Division that morning. In addition, P&C sent seven line crews and support personnel to Central Division that morning. As a result, of a weather bulletin from PSE&G's weather service warning of severe thunderstorms later that afternoon and evening, a conference call was scheduled for 1300 hrs. to discuss staffing needs.

During the 1300 hrs. conference call, PSE&G's weather service predicted that thunderstorms with possible 60 MPH winds, along with isolated tornadoes, would hit the service area that afternoon. Storm restoration plans were reviewed and line force and support personnel coverage for the 1500-2300 and 2300-0700 shifts were made. In addition, tree crew coverage was scheduled.

PSE&G began to feel the effects of these severe thunderstorms during the afternoon on July 22nd with the most plant damage and outages occurring in Southern Division. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties. PSE&G began to attempt to obtain contractor line FTEs from contractors at 1830 hrs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a North American Mutual Assistance Group (NAMAG) conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. PSE&G also made arrangements to move any available line and service crews from other divisions to Southern Division at 2300 hrs. that evening.

Beginning at 0800 hrs. on July 22nd, PSE&G held multiple conference calls concerning storm restoration efforts until July 25th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company. After the 0800 hrs. conference call on July 23rd, PSE&G requested an additional 500 line FTEs from PSEG-LI.

Communications with Board staff concerning this weather event began on July 22nd and continued until July 26th.

PSE&G opened its UEOC from 0600–2100 hrs. on July 23rd and July 24th and from 0600-2000 hrs. on July 25th.

These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more than 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company were interrupted and each of PSE&G's other three operating divisions supplied line and service repair crews to Southern Division.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this weather event are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	31,717	July 24th - `1207 hrs.
Metropolitan	4,369	July 23rd – 1204 hrs
Palisades	6,683	July 23rd – 1720 hrs.
Southern	176,458	July 25th – 1542 hrs.
Total	219,227	

Attached are the following Customer Restoration Summary Graphs which encompass all three weather events:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

During the 0800 hrs. operations conference call on July 22nd, Central Division reported that they still had over 1,300 customers out of service from the thunderstorms that hit their service area during the early evening on July 21st. As a result, Southern Division sent five line crews, two service repair crews and support personnel to Central Division that morning. In addition, P&C sent seven line crews and support personnel to Central Division that morning. As a result, of a weather bulletin from PSE&G's weather service warning of severe thunderstorms later that afternoon and evening, a conference call was scheduled for 1300 hrs. to discuss staffing needs.

During the 1300 hrs. conference call, PSE&G's weather service predicted that thunderstorms with possible 60 MPH winds, along with isolated tornadoes, would hit the service area that afternoon. Storm restoration plans were reviewed and line force and support personnel coverage for the 1500-2300 and 2300-0700 shifts were made. In addition, tree crew coverage was scheduled.

PSE&G began to feel the effects of these severe thunderstorms during the afternoon on July 22nd with the most plant damage and outages occurring in Southern Division. Wind gusts of up to 76 MPH were measured in Burlington and Camden Counties. PSE&G began to attempt to obtain contractor line FTEs from contractors at 1830 hrs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a North American Mutual Assistance Group (NAMAG) conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. PSE&G also made arrangements to move line and service repair crews from other divisions to Southern Division at 2300 hrs. that evening.

Beginning at 0800 hrs. on July 22nd, PSE&G held multiple conference calls concerning storm restoration efforts until July 25th. Participants in the conference calls included representatives from Electric Delivery's General Office staff, the four operating divisions, P&C and ESOC along with personnel from other operating and staff departments of the company. After the 0800 hrs. conference call on July 23rd, PSE&G requested an additional 500 line FTEs from PSEG-LI.

PERSONNEL DEPLOYMENT

In the early evening on July 22nd, PSE&G began to attempt to obtain contractor line FTEs. However, most were in Michigan which was struck by severe thunderstorms several days earlier. PSE&G then requested a NAMAG conference call at 2100 hrs. During that call, PSE&G requested 500 line FTEs. On July 23rd, PSE&G requested 500 line FTEs from PSEG-LI. The results of these requests follow:

Date Requested	Mutual Aid and Line Construction Contractors	Location	No. of FTEs	Date Arrived	Date Released
7/22	Holland Power	Canada	245	7/23	7/25
7/22	Tri-Wire Line	Canada	84	7/23	7/25
7/22	National Grid	New York	37	7/23	7/25
7/22	On-Target	Maine	18	7/23	7/25
7/22	Sargent	Maine	20	7/23	7/25
7/22	Northline	Maine	19	7/23	7/25
7/22	Green Mountain Power	Vermont	43	7/23	7/25
7/22	Riggs Distler	New Jersey	12	7/23	7/25
7/23	Harlan	New York	25	7/23	7/25
7/23	Furguson	New York	35	7/24	7/25
7/23	D&D	New York	48	7/24	7/25
7/23	O'Connell Electric	New York	26	7/24	7/25
7/23	Asplundh	New York	10	7/24	7/25
7/23	Riggs Distler	New York	31	7/24	7/25
7/23	Elecnor-Hawkeye	New York	36	7/24	7/25
7/23	Northline Utilities	New York	16	7/24	7/25
7/23	Northern Line	Maine	13	7/24	7/25
7/23	Asplundh	New York	150	7/24	7/25
7/23	Haugland	New York	72	7/24	7/25
7/23	Henkels & McCoy	Maryland	24	7/24	7/25
Total			964		

An issue developed with paperwork required to allow the crews from Canada to cross the border into the United States. Board staffer James Bruncati was instrumental in resolving the issue.

In addition, PSE&G assigned 69 contractor line FTEs (23 crews) already on the property to Southern Division from July 23-25th.

PSE&G utilized one staging area, at the Burlington County Mall, for the foreign crews where poles, transformers, conductors and other material was stored. The crews received their work assignments and safety briefings at this site.

PSE&G contacted tree trimming contractors on July 23rd for assistance and succeeded in obtaining 203 FTEs to supplement PSE&G's tree trimming FTEs already working on the property. The majority of the additional FTEs arrived on July 23rd and came from Virginia, West Virginia, Massachusetts, New York and New Jersey. They were released on July 25th.

Beginning in the evening of July 22nd, PSE&G began assigning line crews, service repair crews and look-up personnel from the other three operating divisions, and P&C, to Southern Division to assist in service restoration. Look-up personnel from PSE&G's General Office were also assigned to Southern Division beginning on July 23rd. PSE&G utilized personnel from its Gas Delivery Department to stand by wires down in Southern Division beginning late in the evening on July 22nd.

Attached are the following Work Force Graphs which encompass all three weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree FTEs – Company and Contractor Tree FTEs – Outside Contractors Assisting Southern Division
Attachment "L" - Overhead Line Crews and Service Repair Crews Assisting Central Division
Attachment "M" - Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
Attachment "N" - PSE&G Contractor Line Crews Assisting Southern Division
Attachment "O" - Mutual Aid FTEs Assisting Southern Division

Liaisons were assigned to Southern Division from 2300 hrs. on July 22nd until 1640 hrs. on July 25th, and at PSE&G's Inquiry Center from 0800 hrs. on July 23rd until 1640 hrs. on July 25th, to assist in addressing customer service inquiries.

PSE&G contacted the Somerset, Burlington, Camden, Gloucester, Mercer and Monmouth County Offices of Emergency Management (OEMs) with remote support provided the Somerset, Burlington and Camden Offices on the overnight on July 22-23rd. A PSE&G representative was assigned to the Burlington Office on the 0800-1600 hrs. shift on July 23rd. That office, plus those in Camden, Gloucester, Mercer and Monmouth Counties were supported remotely until the afternoon on July 25th.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	32
13 & 4-kV	-	759
Transformers	-	116
Secondaries	-	90
Services	-	1,051
Poles	-	159
Trees	-	537
Total	-	2,744

COMMUNICATIONS

Communications with Board staff concerning this weather event began on July 22nd and continued until July 26th.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media activity was followed and used by PSE&G in targeted messages to the areas in Southern Division that were hardest hit.

A message concerning the very severe thunderstorms and proper storm preparation procedures was sent to PSE&G's Priority 4 (special needs) customers on July 22nd. PSE&G contacted these customers in the affected areas in Southern Division from July 23rd–25th.

PSE&G conducted conference calls with Mayors and other Municipal Officials on July 23rd, 24th and 25th to discuss and review the storm restoration efforts. Members of the Regional Public Affairs Department organized and participated on the calls as did division personnel.

PSE&G's Business Customer Solutions (BCS) Department contacted impacted large customers in Southern Division during this event to communicate storm restoration efforts. The Department utilized liaisons in Southern Division and roving liaisons in heavily impacted areas to aid in this effort.

Water, Ice and Customer Service Centers were established at the following sites:

- 34 Municipal Drive, Lumberton and 1 Municipal Drive, Bordentown on July 23rd and July 24th
- 429 John F. Kennedy Way, Willingboro and 1750 Kresson Road, Cherry Hill on July 24th and 25th

In addition, a Mobile Customer Service Center provided water and ice to:

- A senior home at 429 John F. Kennedy Way, Willingboro on July 23rd
- The County OEM site at 295 Bordentown Chesterfield Road, Chesterfield on July 24th
- The Camden Cooling Community Center, 1200 Merrimac Road, Camden on July 24th

The Customer Service Centers provided ETR updates for customers and were able to issue service orders if required.

Over two million text messages were exchanged with customers during this weather event.

PSE&G's Regional Public Affairs Managers kept in constant contact with municipal and state officials in the areas in Southern Division hardest hit by these very severe thunderstorms. In person meetings, telephone calls, text messages and press releases were all utilized in this communication process. The municipalities of Collingswood and Willingboro were especially hard hit. In addition to the Regional Public Affairs Managers communicating with officials in those two municipalities, PSE&G officers were also in contact with those officials.

INCIDENTS

Bordentown and Collingswood Substations experienced extended outages during this weather event.

Bordentown Substation was shutdown from 1755 hrs. on July 22nd to 1543 hrs. on July 23rd when 1,597 customers were restored. 973 customers were restored at 1646 hrs. Tree damage caused the three 26-kV supply lines to the station to lock out.

Collingswood Substation was shutdown from 1740 hrs. on July 22nd to 2343 hrs. on July 24th affecting 157 customers, all in the business district of the municipality. Tree damage caused the two 26-kV supply lines to the station to lock out. Complicating repairs was the location of the two lines along a railroad right-of-way on opposite sides of the railroad tracks.

SUMMARY

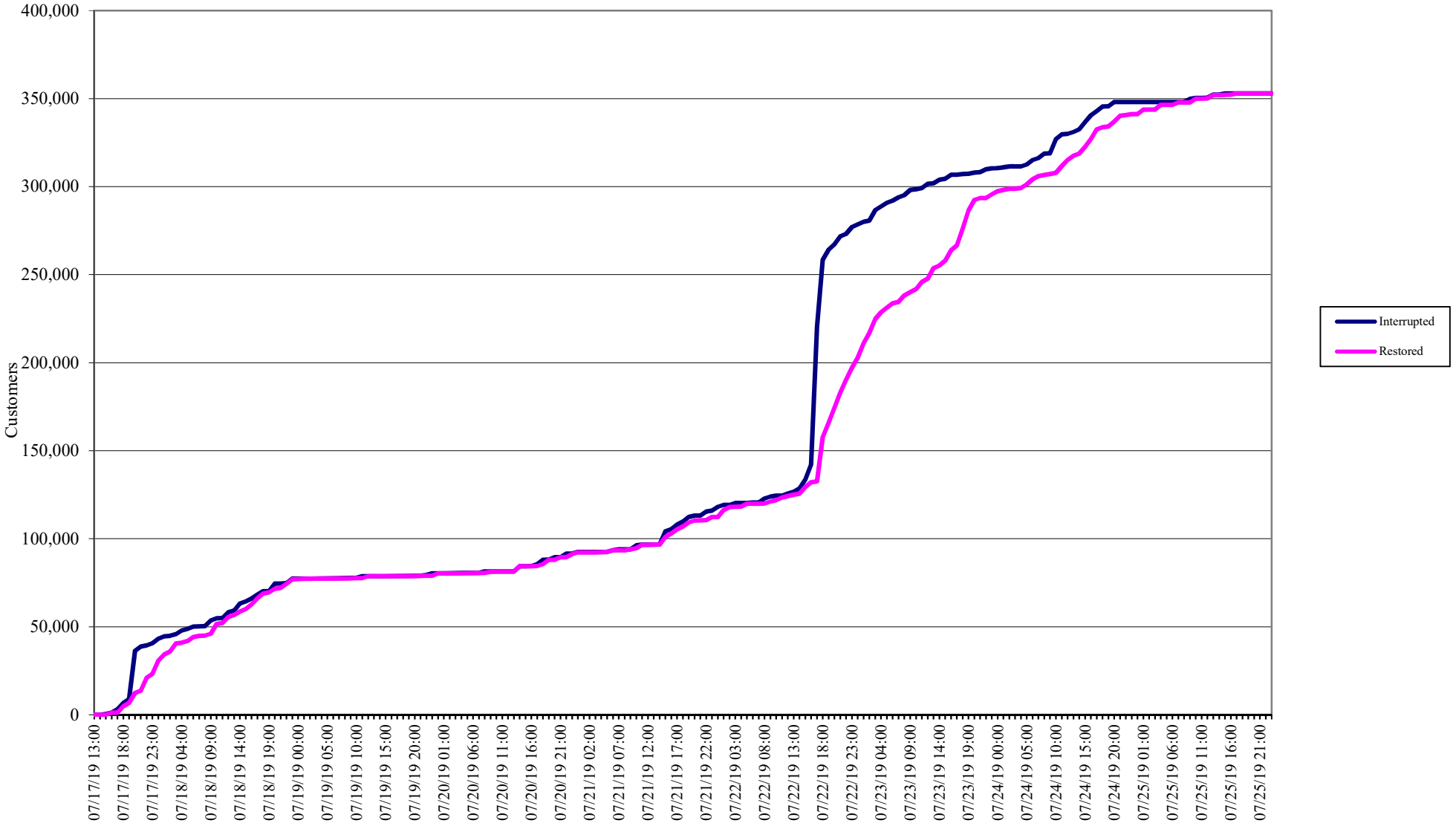
These weather events qualify as a Major Event since 243,406 customers in Southern Division, which is more than 10% of the 579,052 customers in the Division and 352,915 customers Company wide, which is more than 10% of the 2,400, 252 customers served by the Company, were interrupted and each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

PSE&G's excellent relationship with its unions was beneficial during these events.

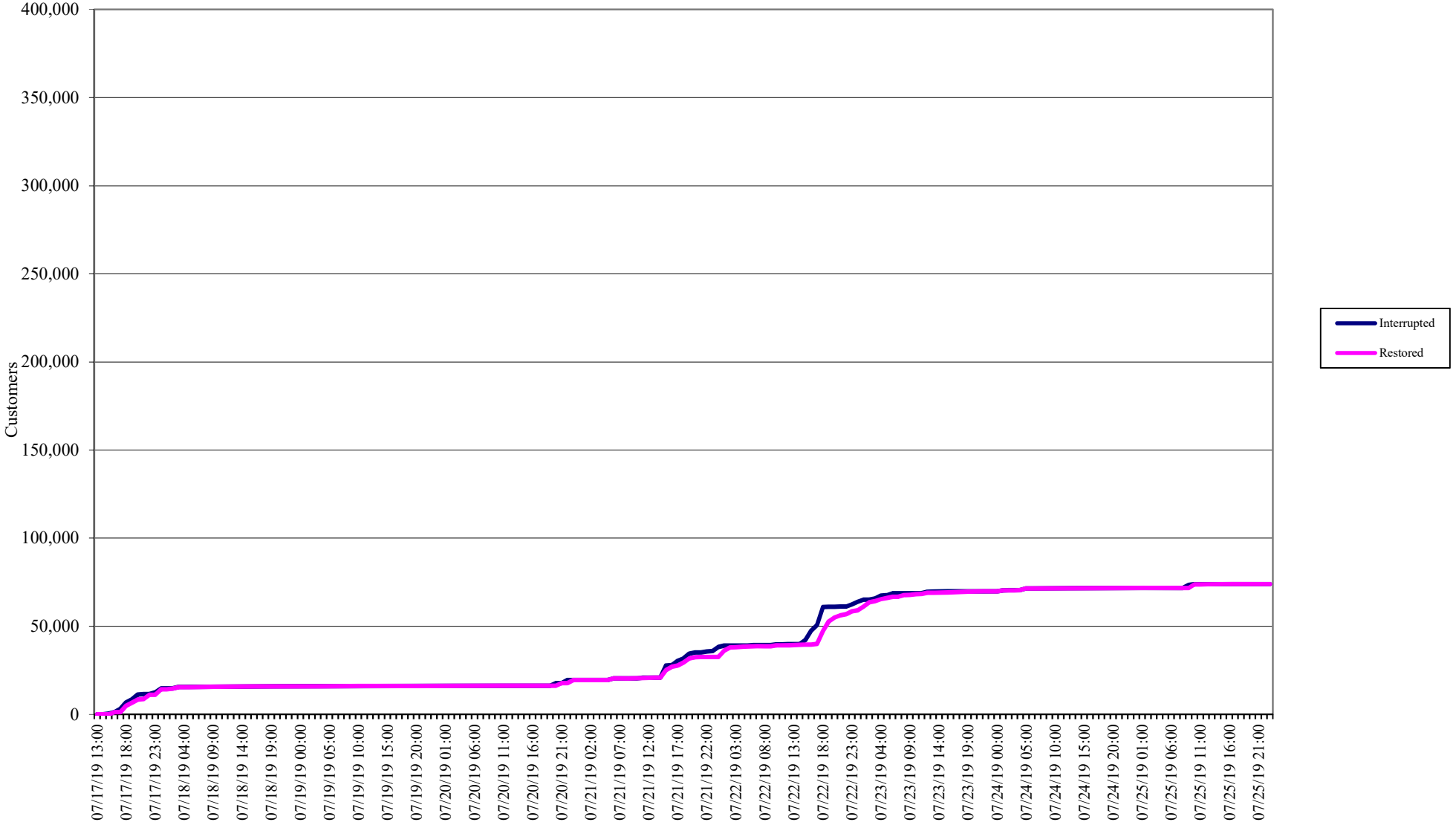
There were no issues involving equipment or material during these events.

DWW: af
8/16/19

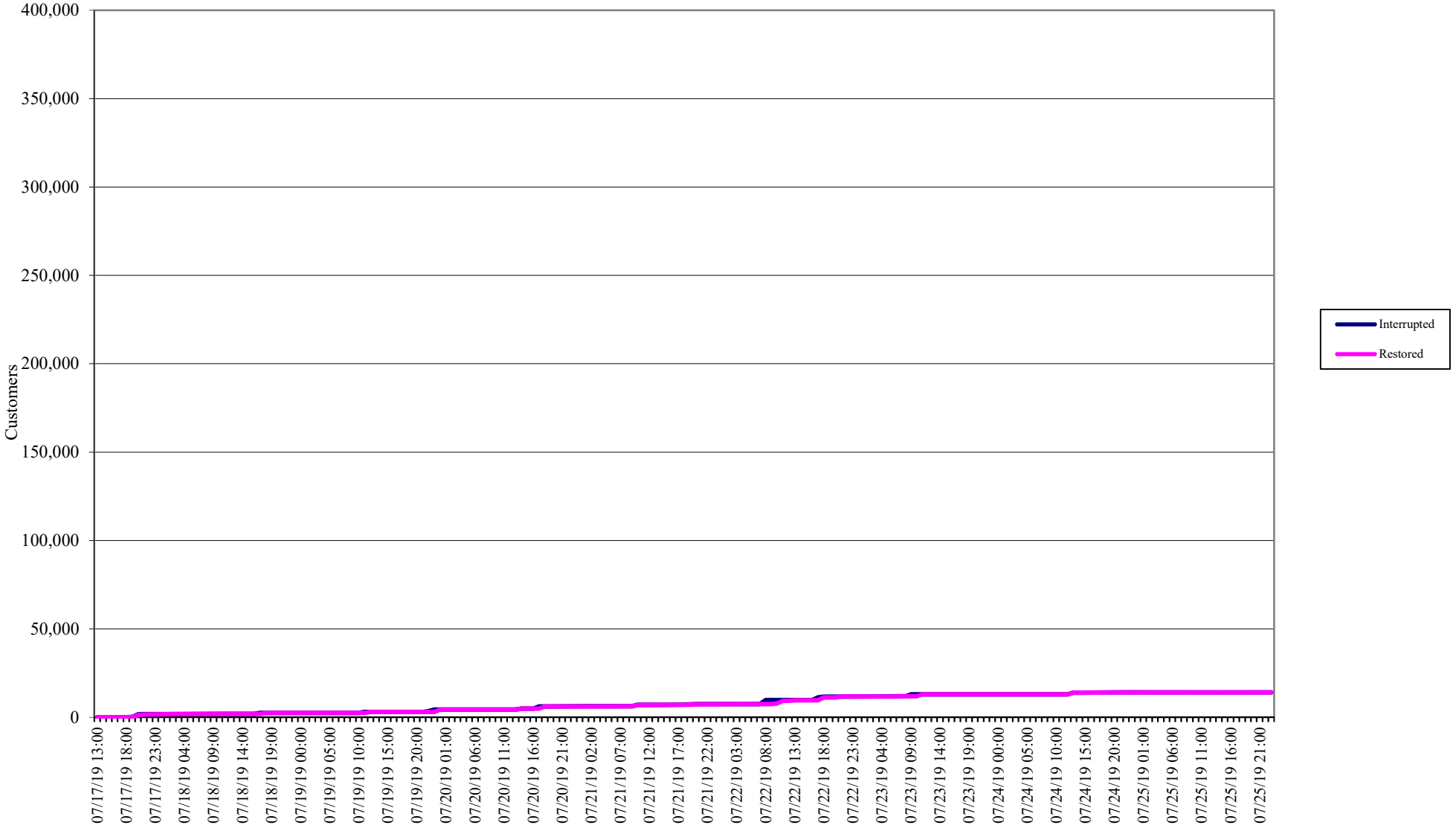
Attachment "A"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Company Wide



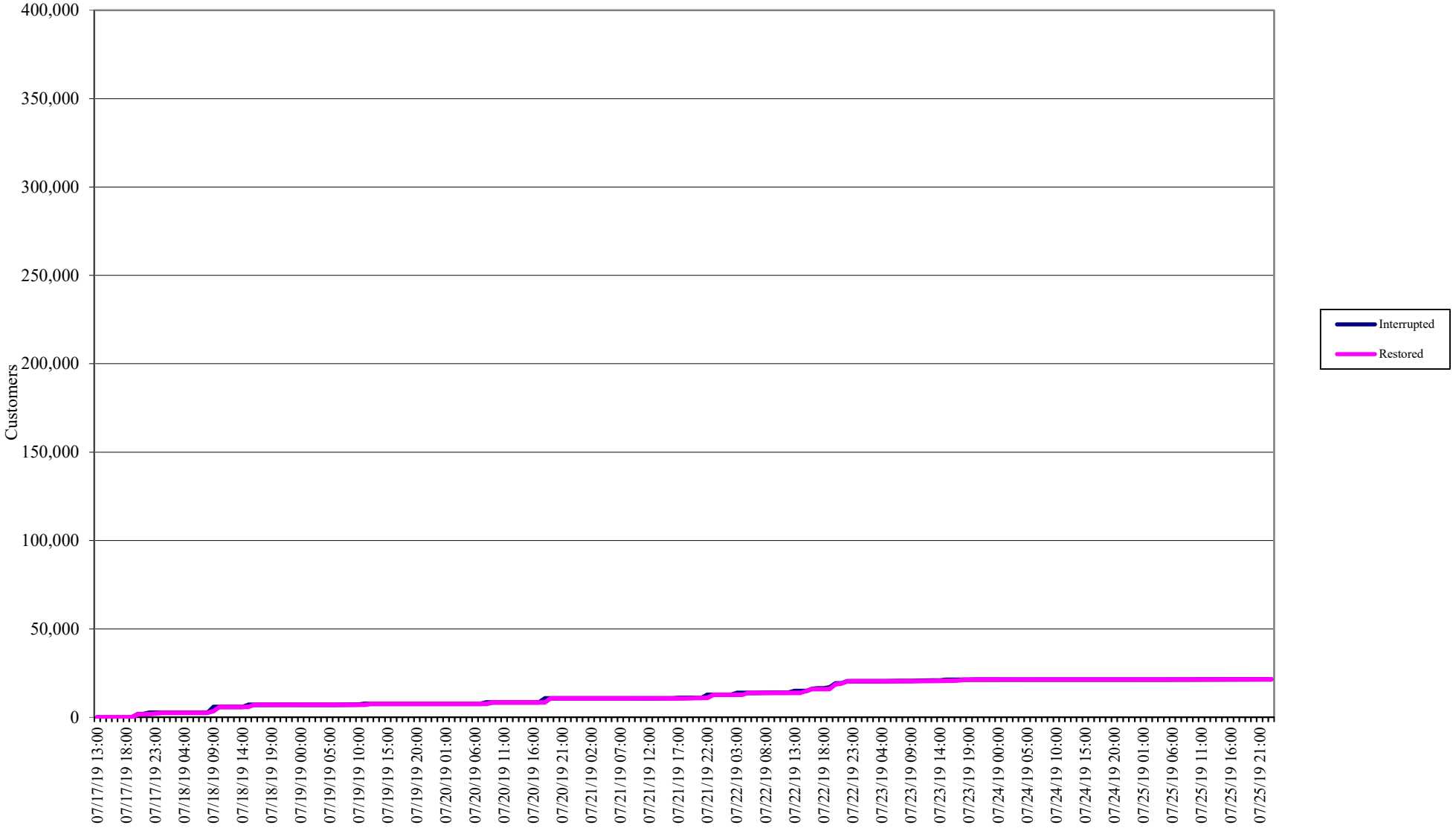
Attachment "B"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Central Division



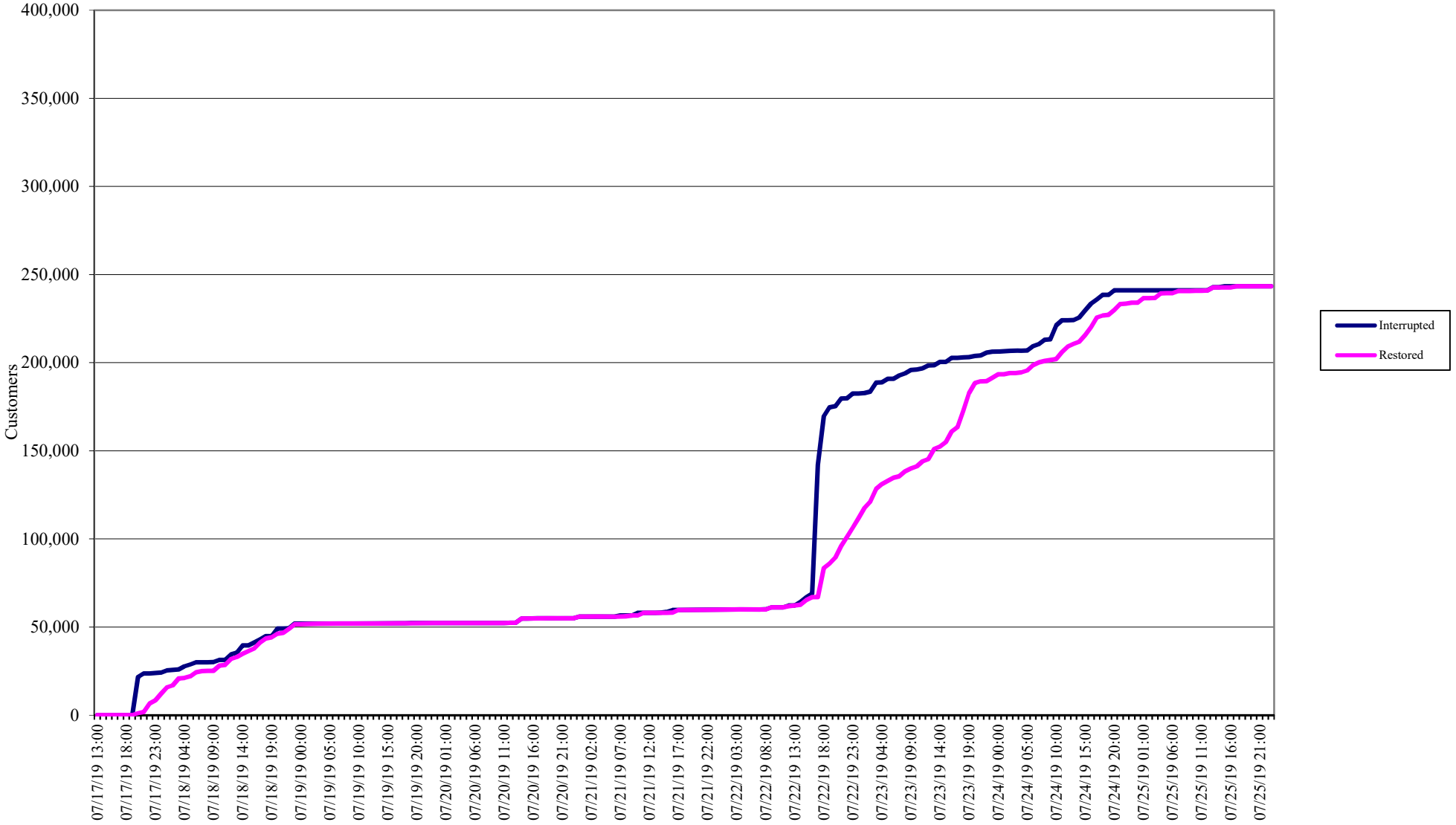
Attachment "C"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Metropolitan Division



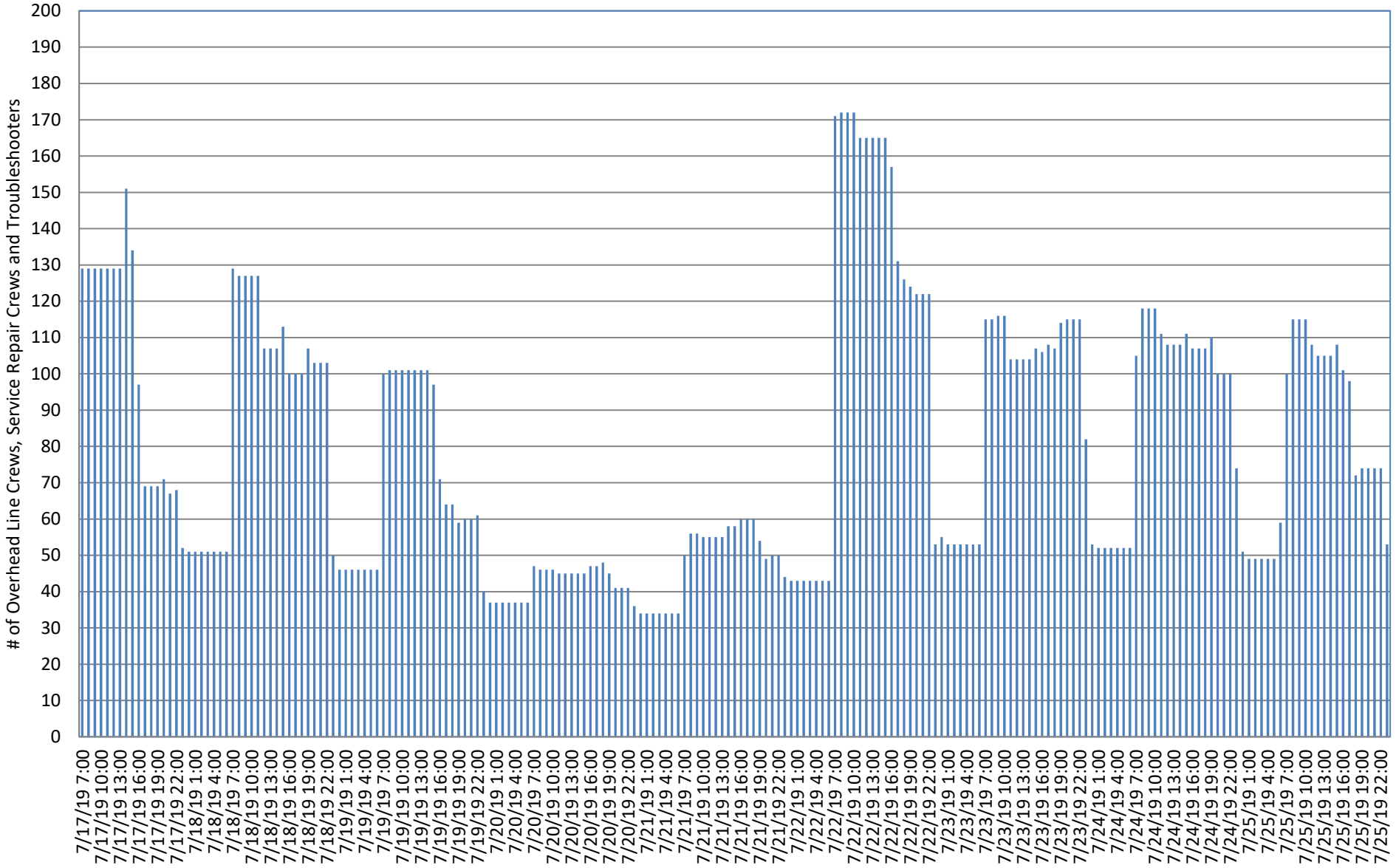
Attachment "D"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Palisades Division



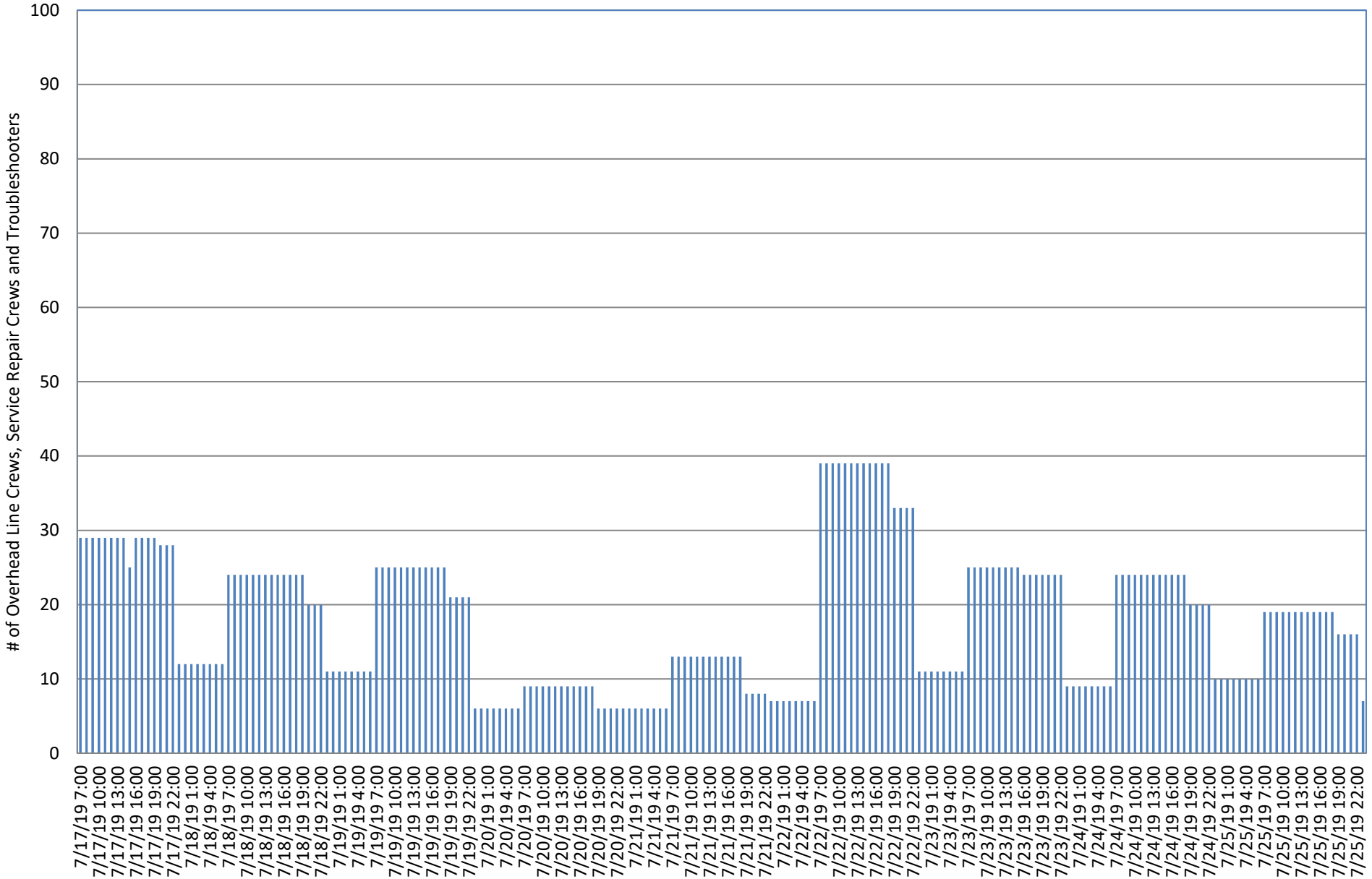
Attachment "E"
PSE&G
Customer Restoration Summary
Severe Weather Events - July 17-25, 2019
Southern Division



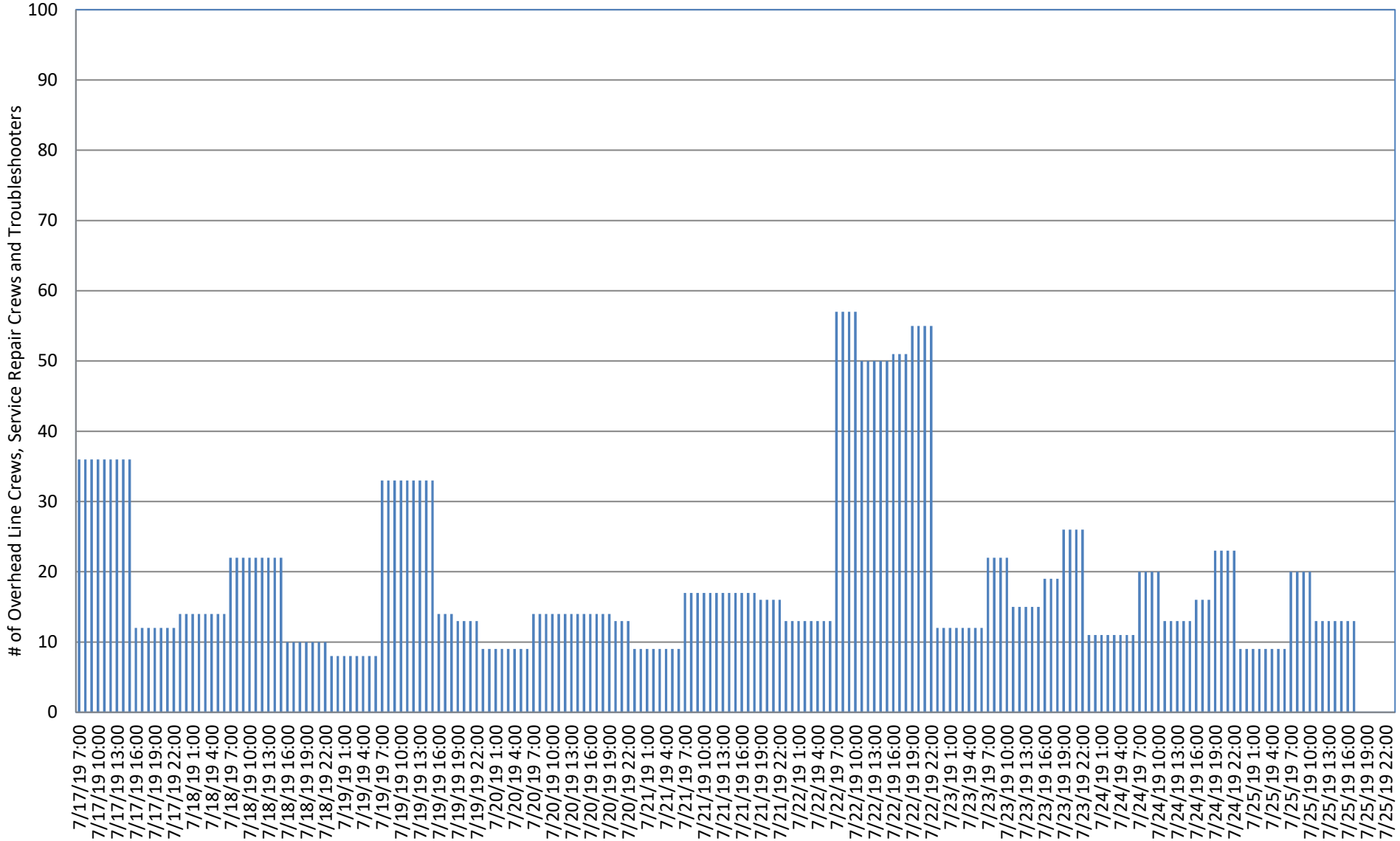
Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Severe Weather Events - July 17-25,2019



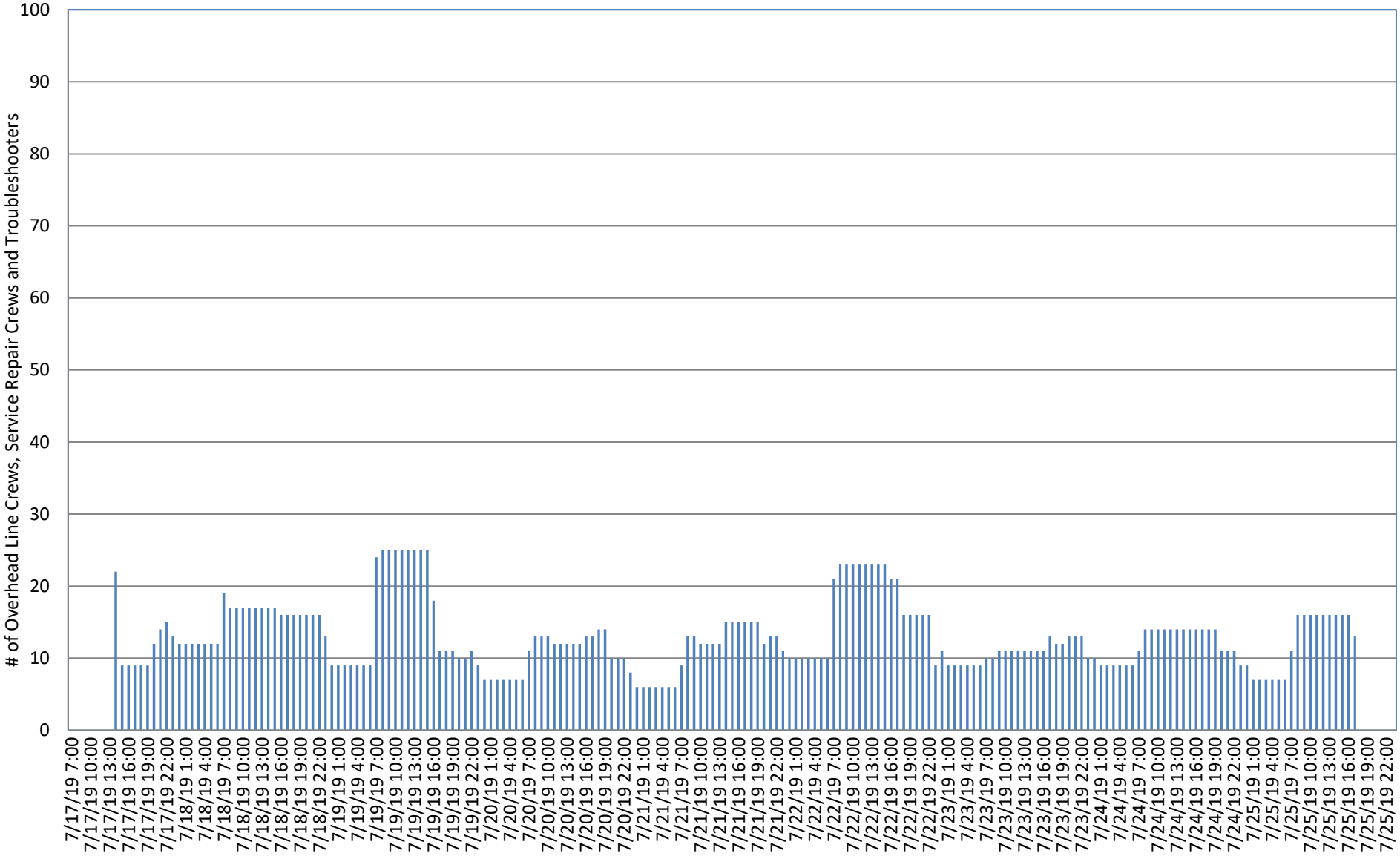
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Severe Weather Events - July 17-25,2019



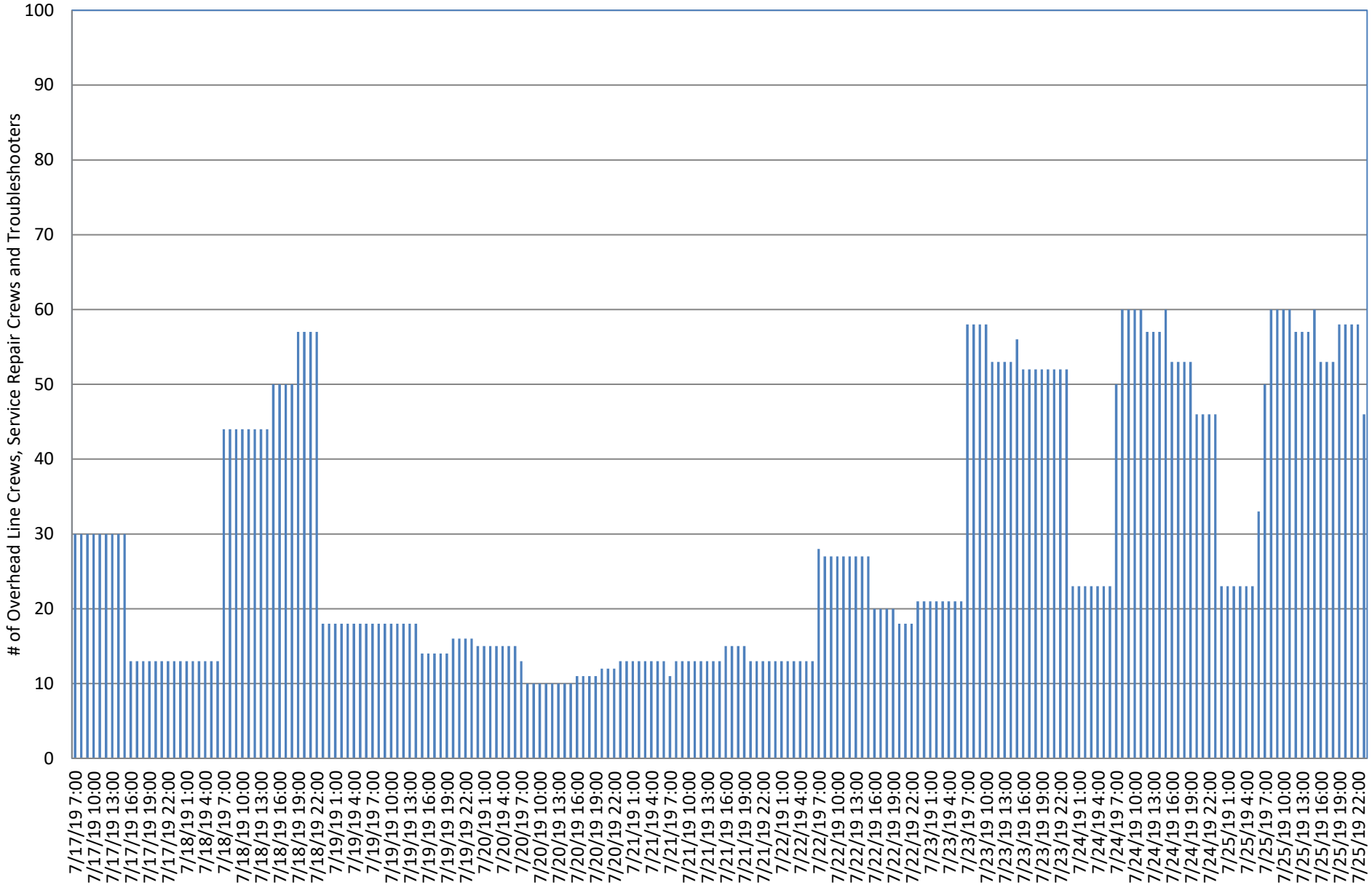
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Severe Weather Events - July 17-25, 2019



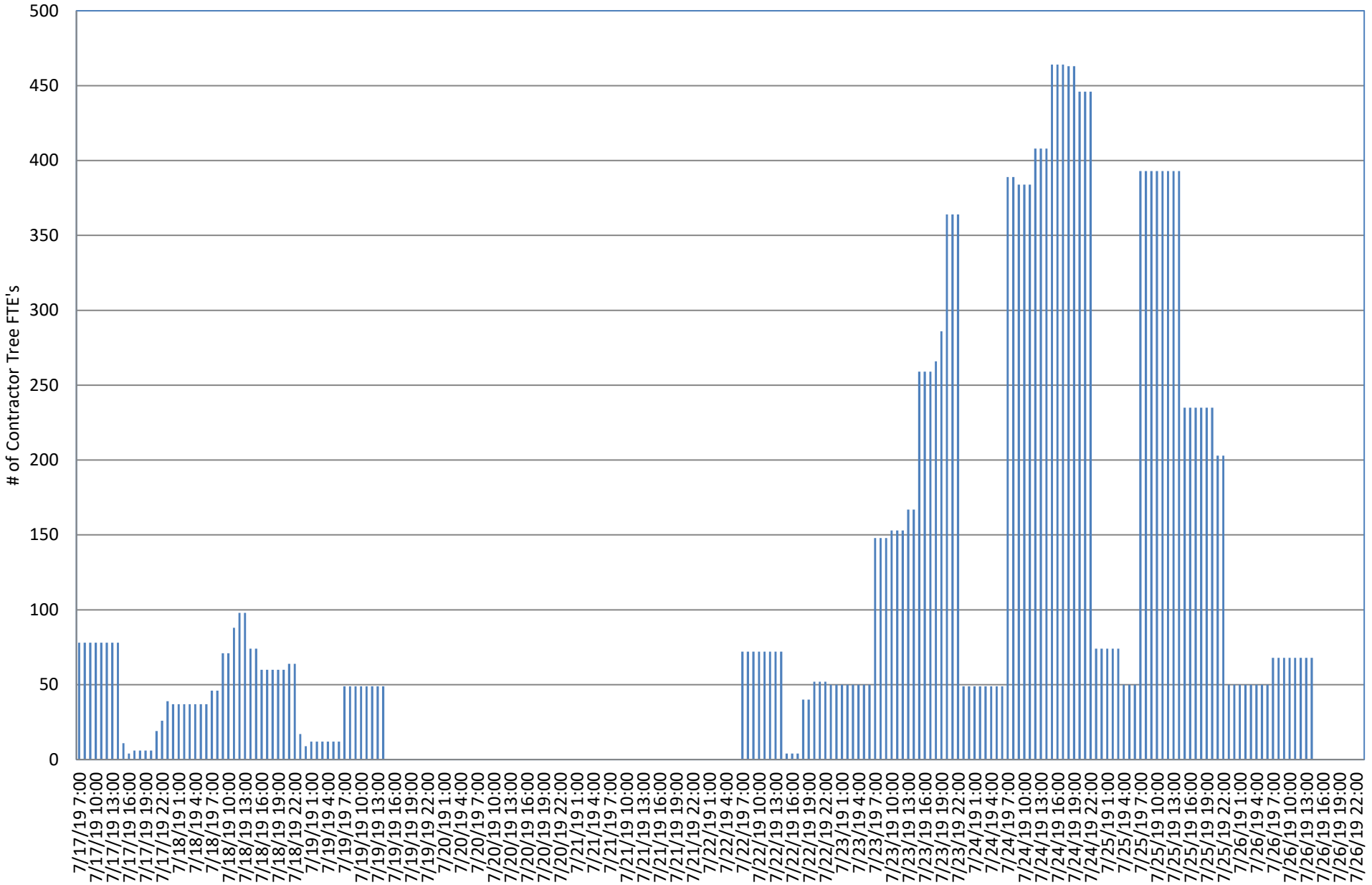
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Severe Weather Events - July 17-25, 2019



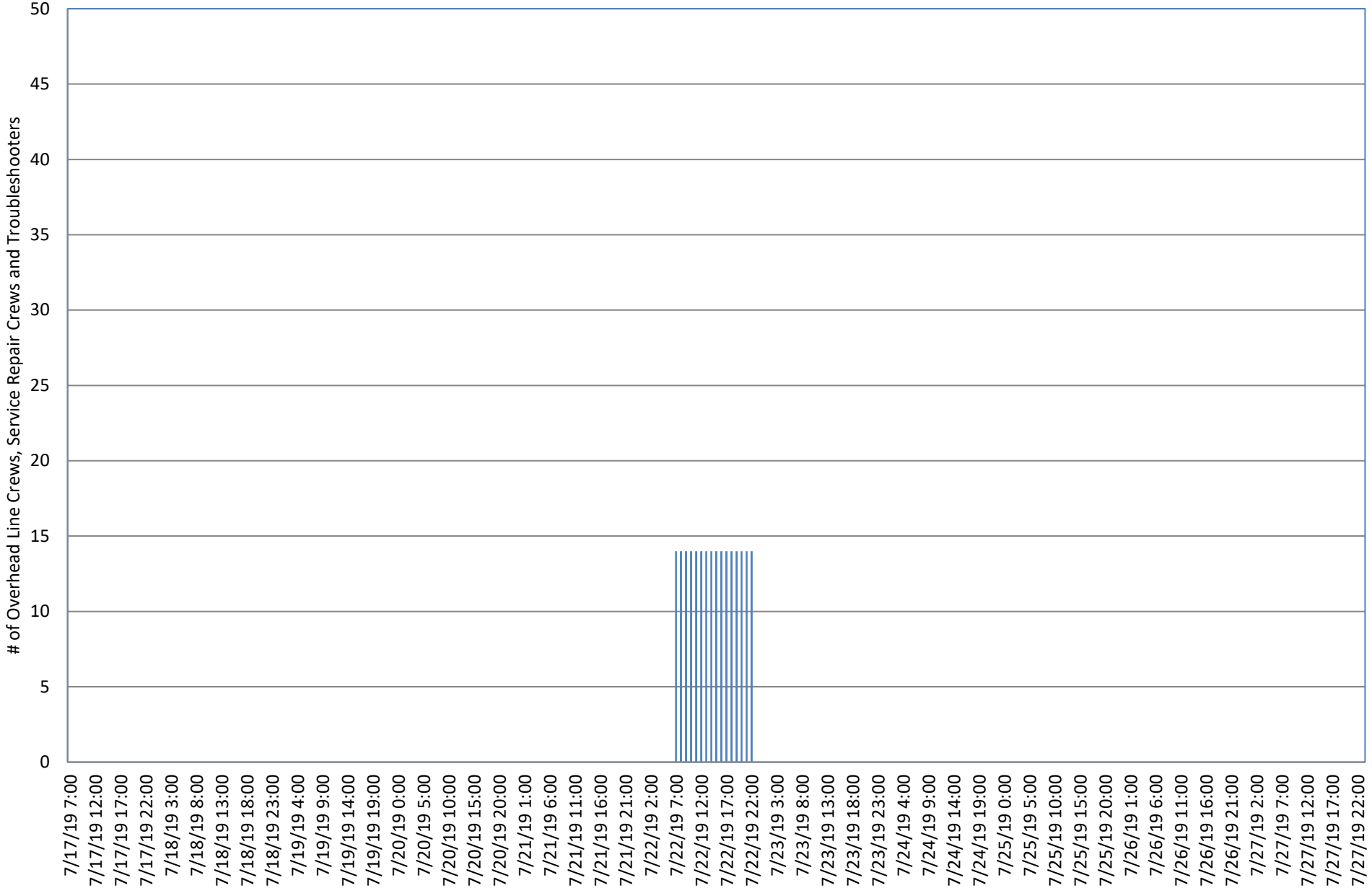
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Severe Weather Events - July 17-25, 2019



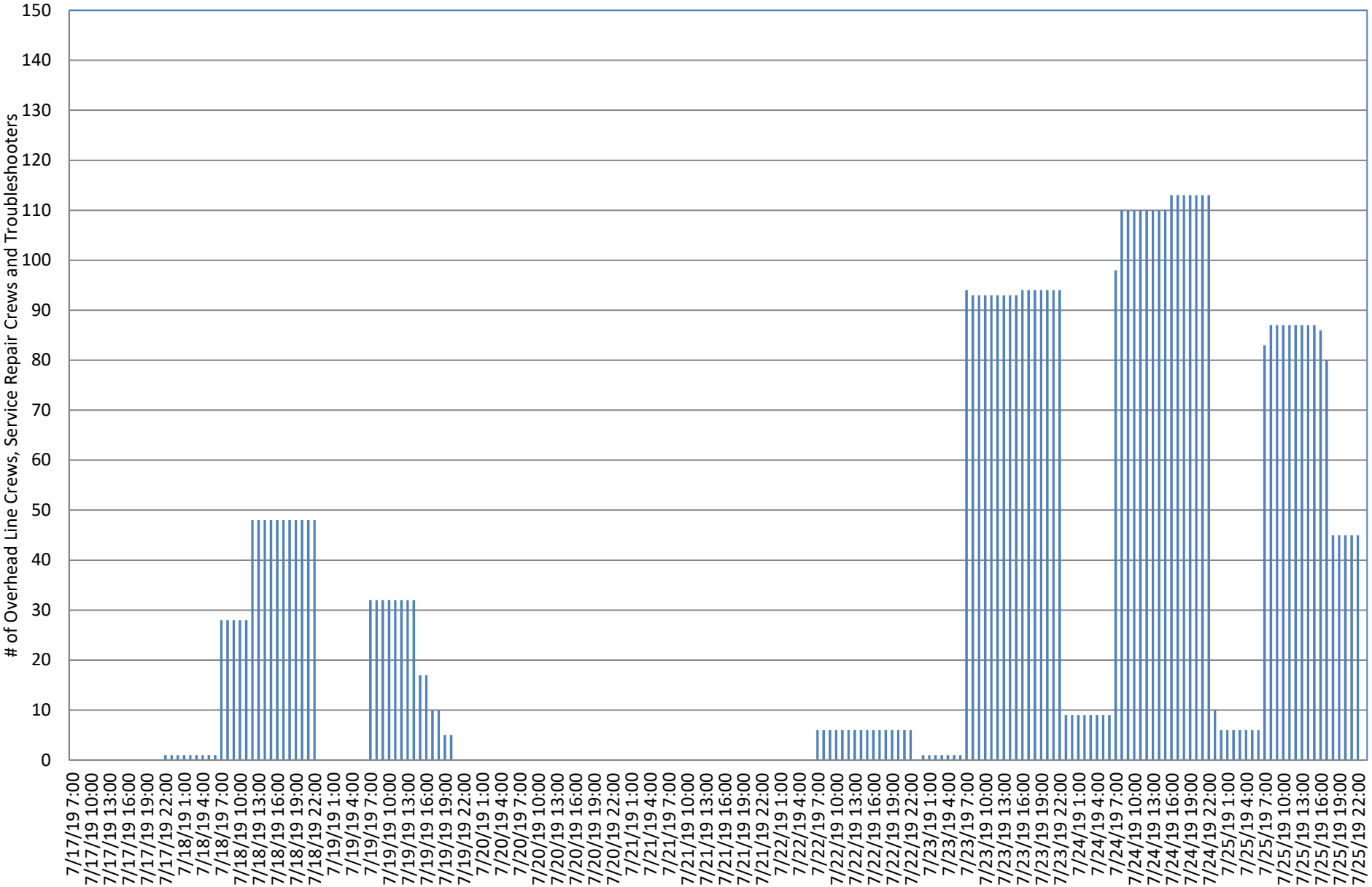
Attachment "K"
PSE&G
Contractor Tree FTE's - Company and Contractor Tree FTE's - Outside Contractors Assisting Southern Division
Severe Weather Events - July 17-25, 2019



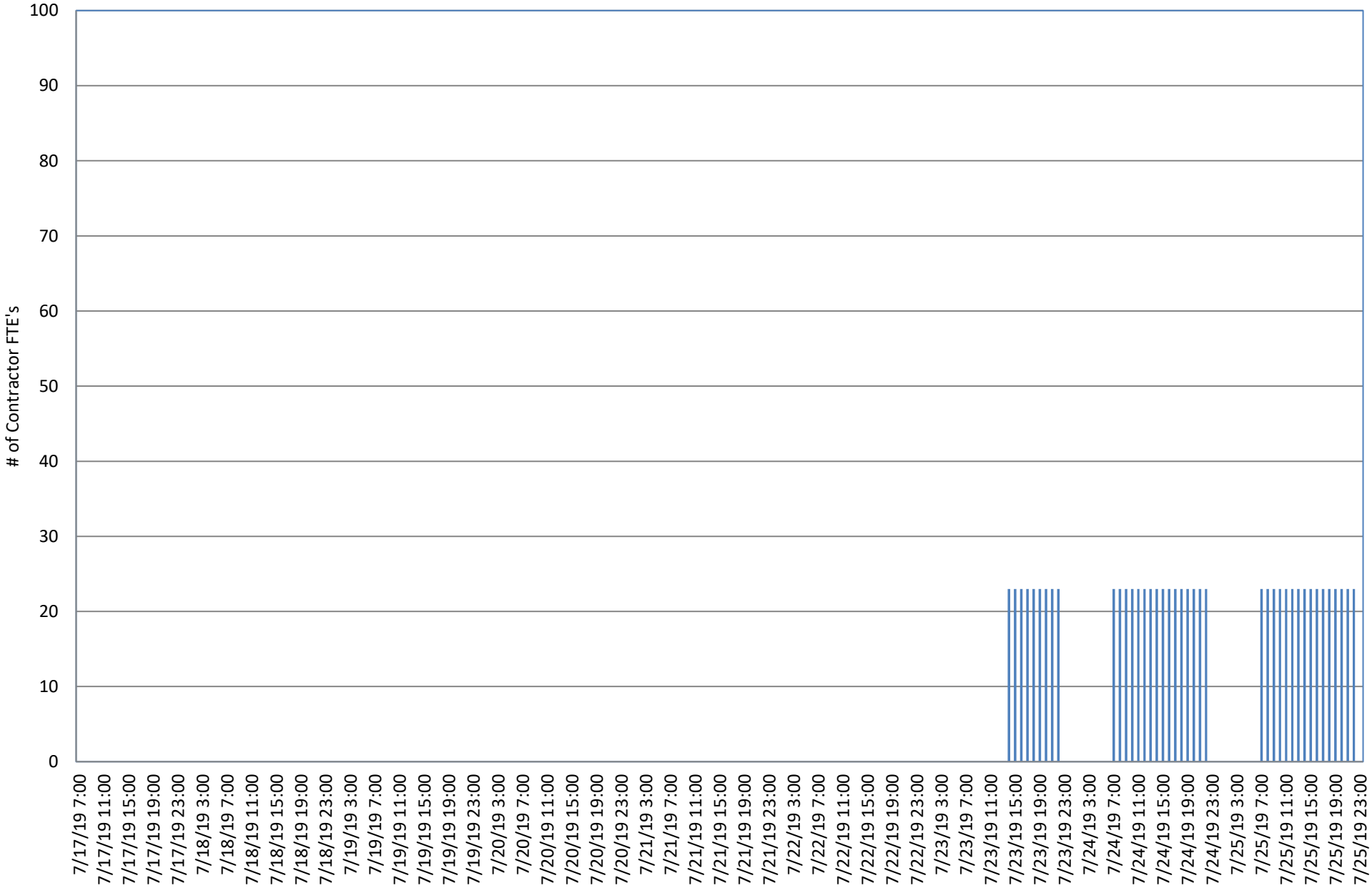
Attachment "L"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Central Division
Severe Weather Events - July 17-25,2019



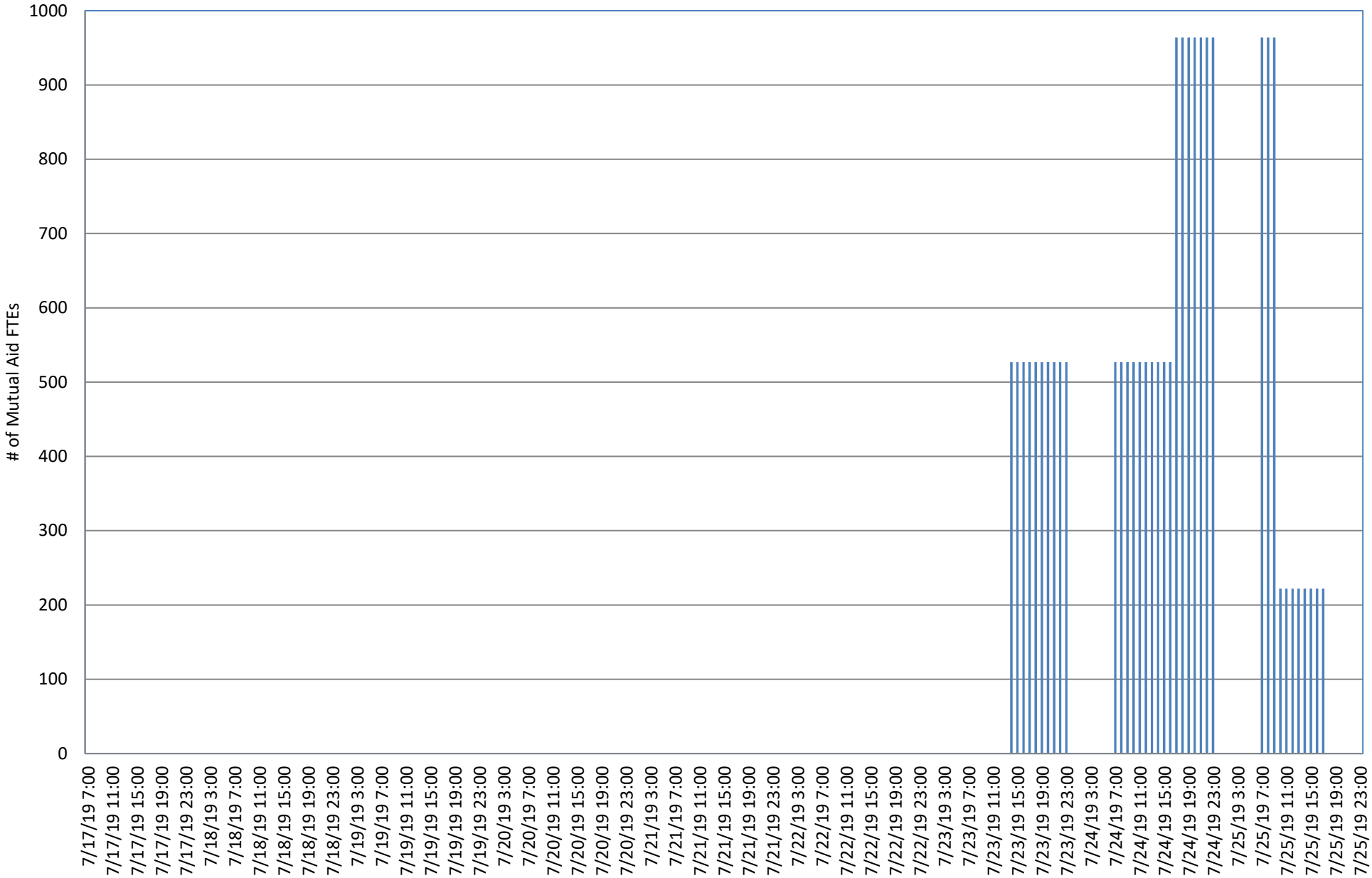
Attachment "M"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters Assisting Southern Division
Severe Weather Events - July 17-25,2019



Attachment "N"
PSE&G
PSE&G Contractor Line Crews Assisting Southern Division
Severe Weather Events - July 17-25,2019



Attachment "O"
PSE&G
Mutual Aid FTEs Assisting Southern Division
Severe Weather Events - July 17-25, 2019



		7/22 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**1,816,649**	**6,339,603**	**8,156,251**	**2,010,595**
2	Contractor/Mutual Aid	2,997,010	7,834,946	10,831,956	7,834,946
3	Tree Removal	467,772	1,746,306	2,214,078	1,746,306
4	Buses	-	-	-	-
5	Other Contractor	292,597	108,490	401,087	108,490
	Total Contractor	**3,757,379**	**9,689,742**	**13,447,121**	**9,689,742**
6	Material	**530,150**	**498,203**	**1,028,353**	**215,760**
7	Food	7,644	38,658	46,301	38,658
8	Lodging	9,494	37,230	46,724	37,230
9	Security	-	-	-	-
10	Water and Ice	-	167,314	167,314	167,314
11	Other	70,996	217,948	288,943	6,991
	Total Other	**88,134**	**461,149**	**549,283**	**250,192**
	Total Incurred	**6,192,311**	**16,988,698**	**23,181,009**	**12,166,290**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**6,192,311**	**16,988,698**	**23,181,009**	**12,166,290**

Matthew M. Weissman
Managing Counsel - State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel: 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

PSEG Services Corporation

June 26, 2020

Via Electronic Mail & Regular Mail

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street – 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
DERECHO AND SEVERE THUNDERSTORMS
JUNE 3-7, 2020

Dear Director Giuliano:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the derecho and severe thunderstorms that affected PSE&G's Southern Division from June 3-7, 2020.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordalisio, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G's REPORT TO THE BPU
MAJOR EVENT
DERECHO AND SEVERE THUNDERSTORMS
JUNE 3 - 7, 2020

EXECUTIVE SUMMARY

During the period of June 3 - 7, 2020, a derecho and severe thunderstorms affected PSE&G's Southern Division. Shortly after noon on June 3, a derecho swept across the division causing extensive plant damage and significant tree damage. Wind gusts of 73 and 72 mph were measured at Moorestown and Delran respectively. The National Weather Service stated that the derecho was moving at 80 mph. Later that evening, a severe thunderstorm struck the division. On June 4 severe thunderstorms struck the division in the afternoon and late evening. These three storms inflicted additional plant damage and caused more tree damage.

As discussed with Board staff, because of the severity of the weather events on June 3 and 4, they will be considered as one Major Event. These weather events quality as a Major Event since 246,075 customers in Southern Division, which is more than 10% of the 585,381 customers in the Division, and 257,209 customers Company wide, which is more than 10% of the 2,430,197 customers served by the Company, were interrupted. Also, each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

During PSE&G's daily 0800 hrs. operations conference call on June 3, PSE&G's weather service predicted strong storms for the entire service territory after 1200 hrs. The storms were predicted to contain straight line wind gusts. PSE&G's storm preparation plans began to be developed and staffing assignments for the 1500 - 2300 hrs. and 2300 - 0700 hrs. shifts were to be scheduled and presented at a 1300 hrs. operations conference call.

At the 1300 hrs. conference call, PSE&G's weather service indicated that the severe thunderstorms, which had already began to hit Southern Division, would be through the division by 1400 hrs. A second line of storms with straight line wind gusts of 70-80 mph and possible tornadoes was predicted to hit the division between 1700 - 2200 hrs. Participants in this conference call, and in the multiple conference calls concerning storm restoration efforts that continued until June 7, included representatives from Electric Delivery's General Office staff, the four operating divisions, Projects and Construction (P&C), the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the Company.

During the call, Southern Division personnel reported multiple sub-transmission and distribution circuit lock-outs, indicating extensive plant damage. Arrangements were made to immediately send line crews, service repair crews and support personnel to Southern Division from the other three operating divisions and P&C to assist Southern Division's personnel in storm restoration. Additional tree trimming crews were also re-directed to Southern Division.

Two subsequent conference calls that afternoon focused on analyzing the outages and preparing for the other three divisions to send crews to Southern Division at 2300 hrs. At the same time, PSE&G was able to secure approximately 75 contractor line FTEs and approximately 200 line FTEs from PSEG-LI. In addition, PSE&G requested a North Atlantic Mutual Assistance Group (NAMAG) conference call at 1715 hrs. during which PSE&G requested 500 Mutual Aid Line FTEs and received a commitment for 436 FTEs.

During the 1900 hrs. operations conference call that evening, PSE&G's weather service predicted a severe thunderstorm would strike Southern Division between 2000 - 2200 hrs. with 55 - 60 mph winds and lightning. Staffing plans for the 2300 - 0700 shift were confirmed. It was announced that two material staging areas were

being established at Rowan College sites in Mount Laurel and Pemberton. Also, three comfort stations for the distribution of water and ice would open on June 4 in Audubon, Lumberton and Willingboro. In addition, a Mayor's conference call to inform municipal officials of storm restoration efforts was scheduled for June 4 at 1100 hrs.

During the 0800 hrs. operations conference call on June 4, PSE&G's weather service predicted another round of severe thunderstorms would strike Southern Division later that afternoon, some of which could contain 50 - 60 mph winds. Southern Division personnel reported that storms struck their service territory during the evening on June 3 causing additional plant damage and more tree damage.

During the late afternoon and late evening on June 4, additional storms struck Southern Division resulting in even more plant damage.

PSE&G scheduled another NAMAG conference call for 2100 hrs. during which PSE&G requested 300 additional Line FTEs and received a commitment for 50 FTEs. In addition on June 4, PSE&G was able to secure 194 tree trimming FTEs from other utilities.

Another Mayors' conference call was scheduled for June 5 at 1100 hrs.

It must be pointed out that the restoration efforts were impacted by the need to observe COVID-19 protocols and work practices.

Communications with Board staff concerning these weather events began on June 3 and continued until June 7.

PSE&G opened a "virtual" Emergency Operations Center (EOC) from 1300 hrs. on June 3 to 1700 hrs. on June 7.

The restoration efforts went extremely well with 45% of the customers interrupted in Southern Division restored to service within one day, 81% within two days, 97% within three days and complete restoration in a little over four days.

OPERATING REPORT

Extended customer interruptions and restoration times for customers during this Mutual Aid assignment are as follows:

Division	Customers Interrupted Extendedly	Final Restoration
Central	3,400	1402 hrs. – 6/7*
Metropolitan	502	1332 hrs. – 6/7*
Palisades	7,232	1600 hrs. – 6/7*
Southern	246,075	1650 hrs. – 6/7
Total	257,209	

*Outages occurred on 6/7

Attached are the following Customer Restoration Summary Graphs for this weather event:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

During the period of June 3 - 7, 2020, a derecho and severe thunderstorms affected PSE&G's Southern Division. Shortly after noon on June 3 a derecho swept across the division causing extensive plant damage and significant tree damage. Wind gusts of 73 and 72 mph were measured at Moorestown and Delran respectively. The National Weather Service stated that the derecho was moving at 80 mph. Later that evening, a severe thunderstorm struck the division. On June 4 severe thunderstorms struck the division in the afternoon and late evening. These three storms inflicted additional plant damage and caused more tree damage.

During PSE&G's daily 0800 hrs. operations conference call on June 3rd, PSE&G's weather service predicted strong storms for the entire service territory after 1200 hrs. The storms were predicted to contain straight line wind gusts. PSE&G's storm preparation plans began to be developed and staffing assignments for the 1500 - 2300 hrs. and 2300 - 0700 hrs. shifts were to be scheduled and presented at a 1300 hrs. operations conference call.

At the 1300 hrs. conference call, PSE&G's weather service indicated that the severe thunderstorms, which had already began to hit Southern Division, would be through the division by 1400 hrs. A second line of storms with straight line wind gusts of 70-80 mph and possible tornadoes was predicted to hit the division between 1700 - 2200 hrs. Participants in this conference call, and in the multiple conference calls concerning storm restoration efforts that continued until June 7, included representatives from Electric Delivery's General Office staff, the four operating divisions, Projects and Construction (P&C), the Electric System Operations Center (ESOC) along with personnel from other operating and staff departments of the Company.

During the call, Southern Division personnel reported multiple sub-transmission and distribution circuit lock-outs, indicating extensive plant damage. Arrangements were made to immediately send line crews, service repair crews and support personnel to Southern Division from the other three operating divisions and P&C to assist Southern Division's personnel in storm restoration. Additional tree trimming crews were also re-directed to Southern Division.

Two subsequent conference calls that afternoon focused on analyzing the outages and preparing for the other three divisions to send crews to Southern Division at 2300 hrs. At the same time, PSE&G was able to secure approximately 75 contractor Line FTEs and approximately 200 Line FTEs from PSEG-LI. In addition, PSE&G's requested a North Atlantic Mutual Assistance Group (NAMAG) at 1715 hrs. during which PSE&G requested 500 Mutual Aid Line FTEs and received a commitment for 436 FTEs.

During the 1900 hrs. operations conference call that evening, PSE&G's weather service predicted a severe thunderstorm would strike Southern Division between 2000 - 2200 hrs. with 55 - 60 mph winds and lightning. Staffing plans for the 2300 - 0700 shift were confirmed. It was announced that two material staging areas were being established at Rowan College sites in Mount Laurel and Pemberton. Also, three comfort stations for the distribution of water and ice would open on June 4 in Audubon, Lumberton and Willingboro. In addition, a Mayor's conference call to inform municipal officials of storm restoration efforts was scheduled for June at 1100 hrs.

During the 0800 hrs. operations conference call on June 4, PSE&G's weather service predicted another round of severe thunderstorms would strike Southern Division later that afternoon, some of which could contain 50 - 60

mph winds. Southern Division personnel reported that storms struck their service territory during the evening on June 3 causing additional plant damage and more tree damage.

During the late afternoon and late evening on June 4, additional storms struck Southern Division resulting in even more plant damage.

PSE&G scheduled another NAMAG conference call at 2100 hrs. during which PSE&G requested 300 additional Line FTEs and received a commitment for 50 FTEs. In addition, on June 4, PSE&G was able to secure 194 tree trimming FTEs from other utilities.

Another Mayors' conference call was scheduled for June 5 at 1100 hrs.

It must be pointed out that the restoration efforts were impacted by the need to observe COVID-19 protocols and work practices.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for this weather event:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Overhead Line Crews, Service Repair Crews, Troubleshooters, Service Dispatchers and Substation Operators Assisting Southern Division
Attachment "M" - Mutual Aid Line FTEs Assisting Southern Division

Listed below is the "Mutual Aid Crews List" for this weather event:

Mutual Aid Crews List					
Company name	Home Location	FTEs	Arrival Status	Acquired VIA	Release Status
PSEG-LI Internal Crews	Long Island, NY	16	Arrived 6/5/20 - 3pm	Outside NAMAG 6/4/2020	Released as of 06.06.20 @ 0700
PSEG-LI Asplundh	Long Island, NY	93	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Asplundh	Long Island, NY	40	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Haugland	Long Island, NY	55	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Haugland	Long Island, NY	7	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
Danella	NJ/PA	34	Arrived 6/3/2020 - 8pm	Outside NAMAG 6/3/2020	Released as of 06.06.20 @ 0700
PSEG-LI Elecnor Hawkeye	Long Island, NY	50	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
PSEG-LI Elecnor Hawkeye	Long Island, NY	4	Arrived 6/4/2020 - 1pm	Outside NAMAG 6/3/2020	Released as of 06.07.20 @ 1700
Mc Phee Electric	NJ/PA	11	Already On Property 6/3/20	P&C Contractors	Released as of 06.06.20 @ 0700
Riggs-Distler	NJ/PA	21	Arrived on property 6/3/2020 - 8pm	Outside NAMAG 6/3/2020	Released as of 06.06.20 @ 0700
Henkels - Aberdeen	Maryland	14	Already On Property 6/3/20	P&C Contractors	Released as of 06.07.20 @ 1700
Michael's Power	Wisconsin	9	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
D&D Power Team #1, Central Hudson Crews	New York	30	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
D&D Power Team #2, National Grid Crews	New York	25	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
O'Connell Electric AvanGrid Crews Team #1	Plattsburg NY	15	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
O'Connell Electric Avagrid Crews Team #2	Plattsburg NY	16	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
MTV Line Eversource Crews Construction	Massachussetts	11	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
EJ Electric Central Hudson Crews	New York	30	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
AvanGrid NY - RGE, Comprised of Various Contractors	New York	75	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Hauglaund Energy-Central Hudson Crews	New York	7	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Riggs Distsler - United Illuminating Crews,	Connecticut	54	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700

Asplundh Eversource Crews	New York	74	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Gratten Line Eversource Crews	New York	14	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Asplundh Eversource MASSACHUSSETTS	Massachussetts	36	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
United Illuminating Company	Connecticut	41	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Cianbro Electric Eversource Crews	New Hampshire	14	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Con Edison	New York	49	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Harlan Electric - National Grid	New York	26	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
Northline	New York	37	Arrived On Property 6/4/2020 3pm-5pm	From NAMAG Request 6/3/20	Released as of 06.06.20 @ 0700
CMP Internal	Maine	50	Arrive on property 6/5/2020 - 5pm	From NAMAG Request 6/4/20	Released as of 06.06.20 @ 0700
Valiant	NJ/PA	22	Arrived On Property 6/5/2020 - 9am-11am	Outside NAMAG 6/4/2020	Released as of 06.07.20 @ 1700
PSEG LI - Internal Service Crews	Long Island, NY	24	Arrived On Property 6/5/2020 - 11am	Outside NAMAG 6/4/2020	Released as of 06.06.20 @ 0700
	Total	1004			

On June 4, PSE&G was able to secure 194 contractor tree trimming FTEs as listed below:

Off-System Crew Log									
Vendor	Requested	Utility	State	Arrived		Departed		Crew #	FTE #
				Date	Time	Date	Time		
Asplundh	6/4/2020	UGI	PA	6.5.20	7:30am	6.6.20	7:00am	5	11
Asplundh	6/4/2020	Con Ed	NY	6.4.20	11:00pm	6.6.20	7:00am	10	22
Asplundh	6/4/2020	PSEG LI	NY	6.5.20	11:30am	6.6.20	3:30pm	2	48
ARS	6/4/2020	HG&E	MA	6.5.20	4:00am	6.6.20	7:00am	6	13
ARS	6/4/2020	PSEG LI	NY	6.5.20	2:00am	6.6.20	8:00pm	13	28
NG Gilbert	6/4/2020	Potomac Ed	MD	6.5.20	11:00am	6.6.20	7:00am	10	24
NG Gilbert	6/4/2020	NYSEG	NY	6.5.20	9:30am	6.6.20	7:00am	8	18
NG Gilbert	6/4/2020	First Energy	NJ	6.5.20	10:00am	6.6.20	8:00pm	13	30

Look-up personnel from the other three operating divisions, P&C and Asset Management & Centralized Services (AMSC) supported the storm restoration process in Southern Division from June 3 – June 7. In addition, Gas Delivery personnel were utilized in Southern Division from June 3-June 5 to stand by downed wires.

Liaisons were assigned to Southern Division from June 3 to June 7 to assist in addressing customer inquiries. Remote liaisons were also assigned to the Inquiry Center from June 3 to June 6 to assist in addressing customer inquiries.

The Burlington, Camden, Gloucester and Mercer County Offices of Emergency Management (OEMs) were contacted on June 3. Only the Camden office opened and was remotely supported by liaisons from June 3 to June 6.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	40
13 & 4-kV	-	668
Transformers	-	221
Secondaries	-	135
Services	-	347
Poles	-	255
Trees	-	724
Total	-	2,390

INCIDENTS

Bordentown Substation was shut down at 1240 hrs. on June 3 affecting 2,663 customers when both 26-kV supply lines were interrupted. It was restored at 1758 hrs. on June 3 when the L-428 was energized.

Ewing Substation was shut down at 1240 hrs. on June 3 affecting 4,690 customers when both 69-kV supply lines were interrupted. It was restored at 1737 hrs. on June 3 when the V-724 was energized.

Collingswood Substation was shut down at 1633 hrs. on June 3 affecting 157 customers when both 26-kV supply lines were interrupted. It was restored at 2030 hrs. on June 3 when the I-373 was energized.

Woodlynne Substation was shut down at 1943 hrs. on June 3 affecting 11,319 customers when both 26-kV supply lines were interrupted. It was restored at 2235 hrs. on June 3 via the W-387, an emergency tie line installed under Energy Strong I.

COMMUNICATIONS

Communications with Board staff concerning this weather event began on June 3 and continued until June 7.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspaper, television and radio information requests during this period. In addition, social media posts to particularly hard hit communicates provided support information including the location of the three comfort stations.

Over 1.2 million emails were sent to customers regarding storm preparedness.

A notification to PSE&G's critical needs (P-4) customers about the storm was issued in the early afternoon on June 3 and notifications were also included in the outbound calls made with Estimated Times of Restoration (ETR).

Conference calls with mayors and other municipal officials concerning storm restoration efforts were held at 1100 hrs. on June 4 and June 5. Members of the Regional Public Affairs Department organized the calls and participated on the calls as did Southern Division personnel.

PSE&G's Regional Public Affairs Managers kept in constant contact with municipal and state officials in the areas in Southern Division hardest hit by these very severe thunderstorms. In person meetings, telephone calls, text messages and press releases were utilized in this communication process. In addition to the Regional Public Affairs Managers communicating with municipal officials in the hardest hit municipalities, PSE&G officers were also in contact with those officials.

SUMMARY

As discussed with Board staff, because of the severity of the weather events on June 3 and 4, they will be considered as one Major Event. These weather events quality as a Major Event since 246,075 customers in Southern Division, which is more than 10% of the 585,381 customers in the Division, and 257,209 customers Company wide, which is more than 10% of the 2,430,197 customers served by the Company were interrupted. Also, each of PSE&G's other three operating divisions supplied line and service restoration crews to Southern Division.

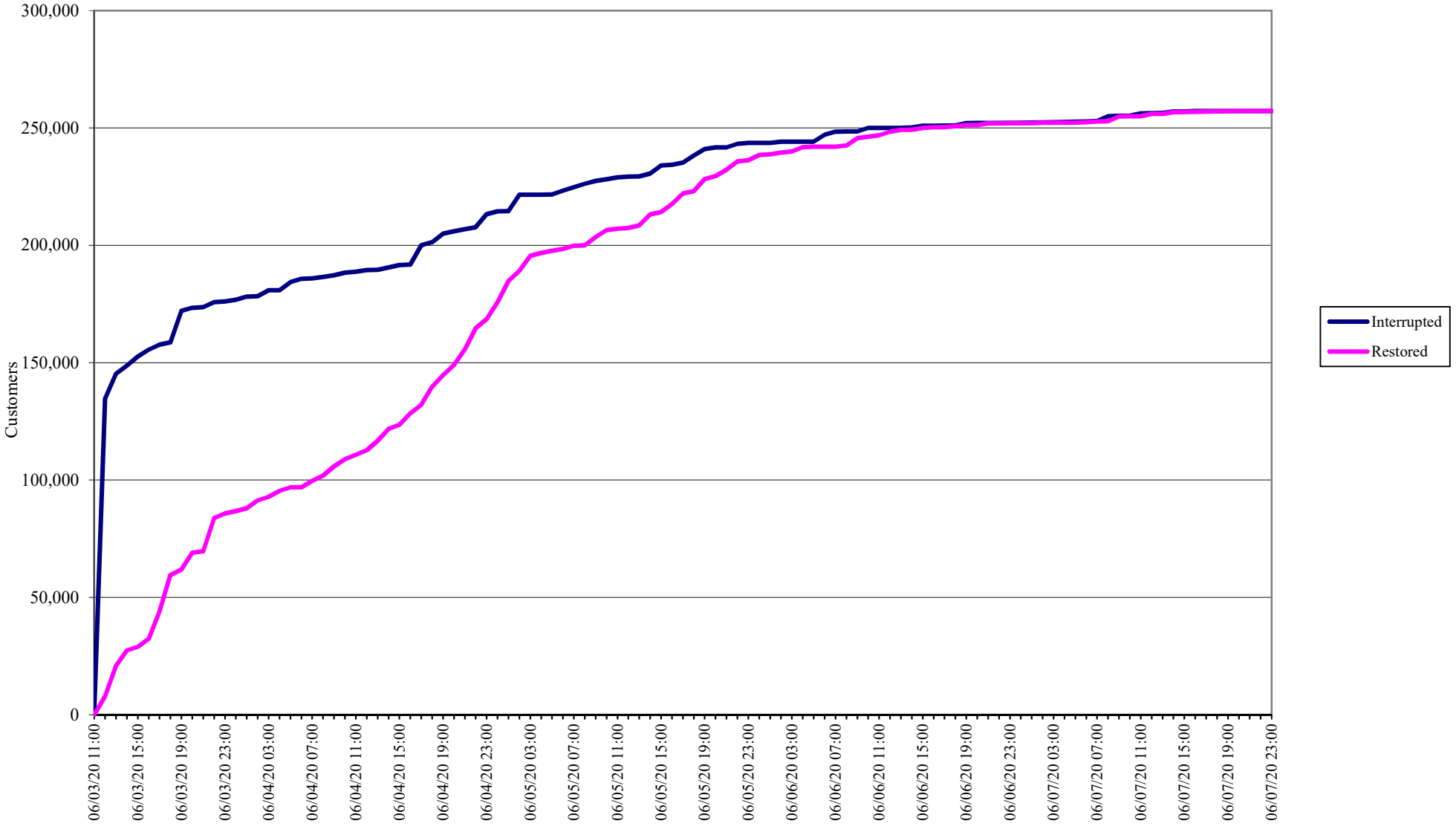
The restoration efforts went extremely well with 45% of the customers interrupted in Southern Division restored to service within one day, 81% within two days, 97% within three days and complete restoration in a little over four days.

PSE&G's excellent relationship with its unions was beneficial during this event.

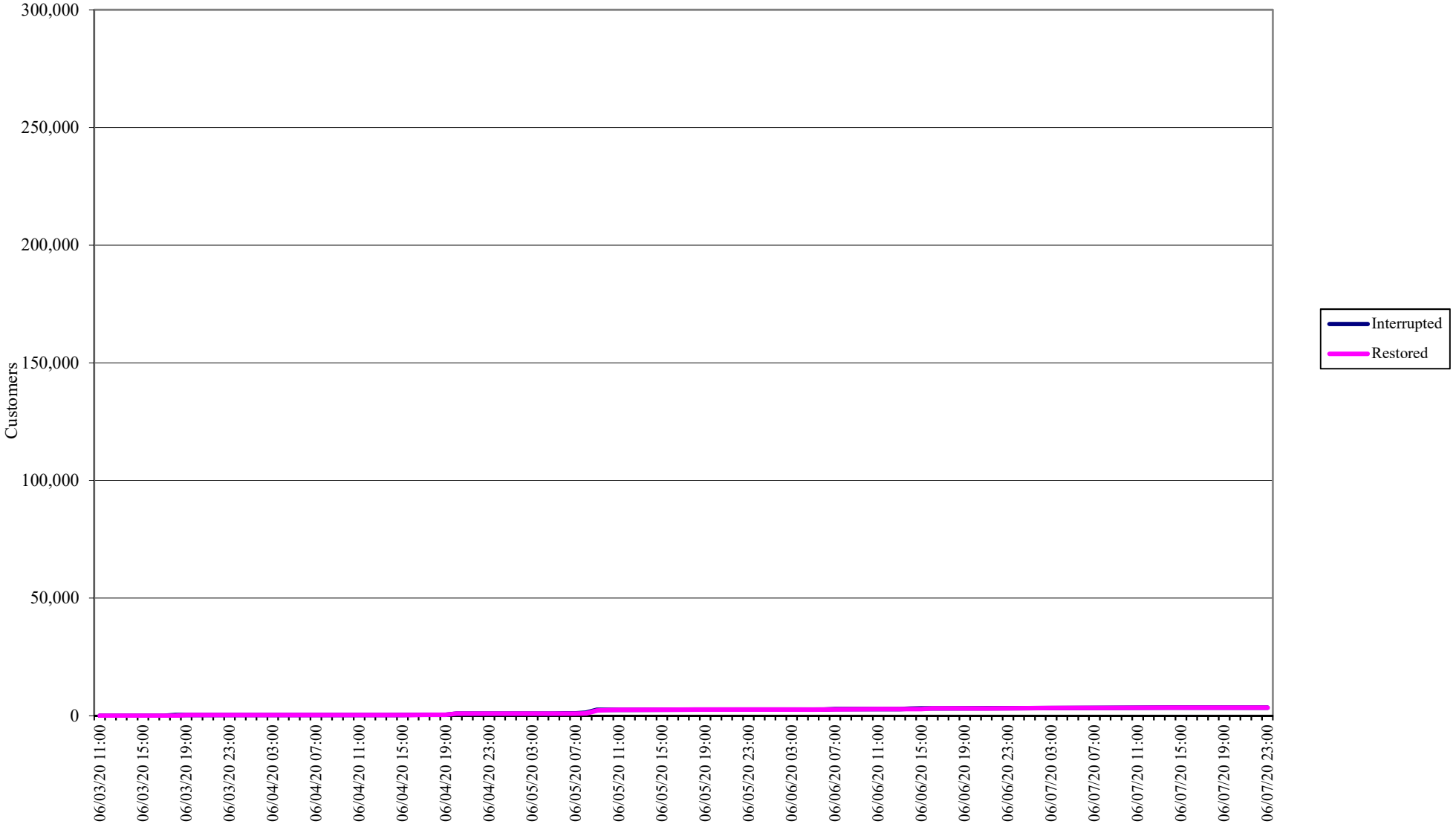
These were no issues involving equipment or material during this event.

DWW:bmc
6/24/20

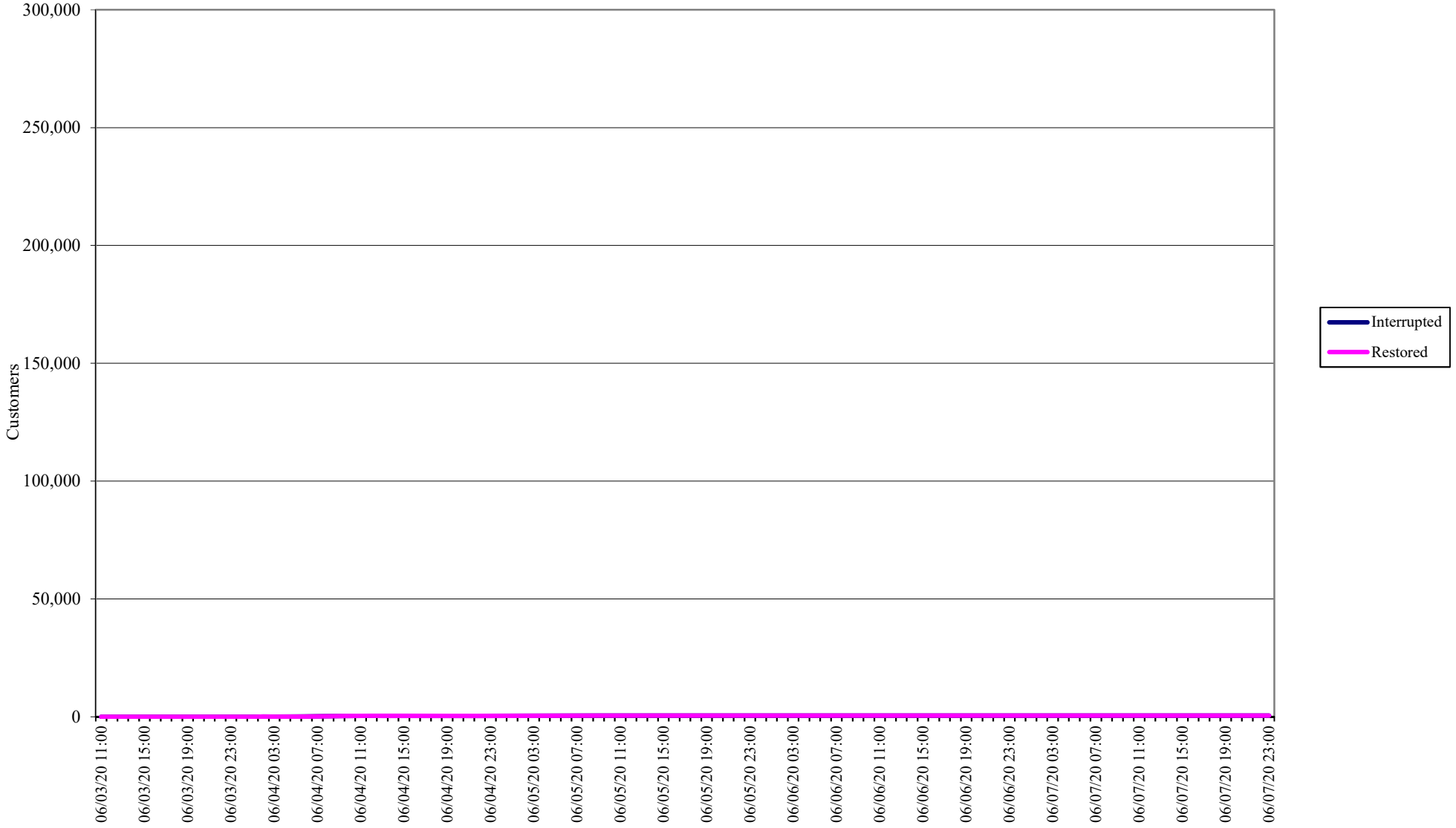
Attachment "A"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Company Wide



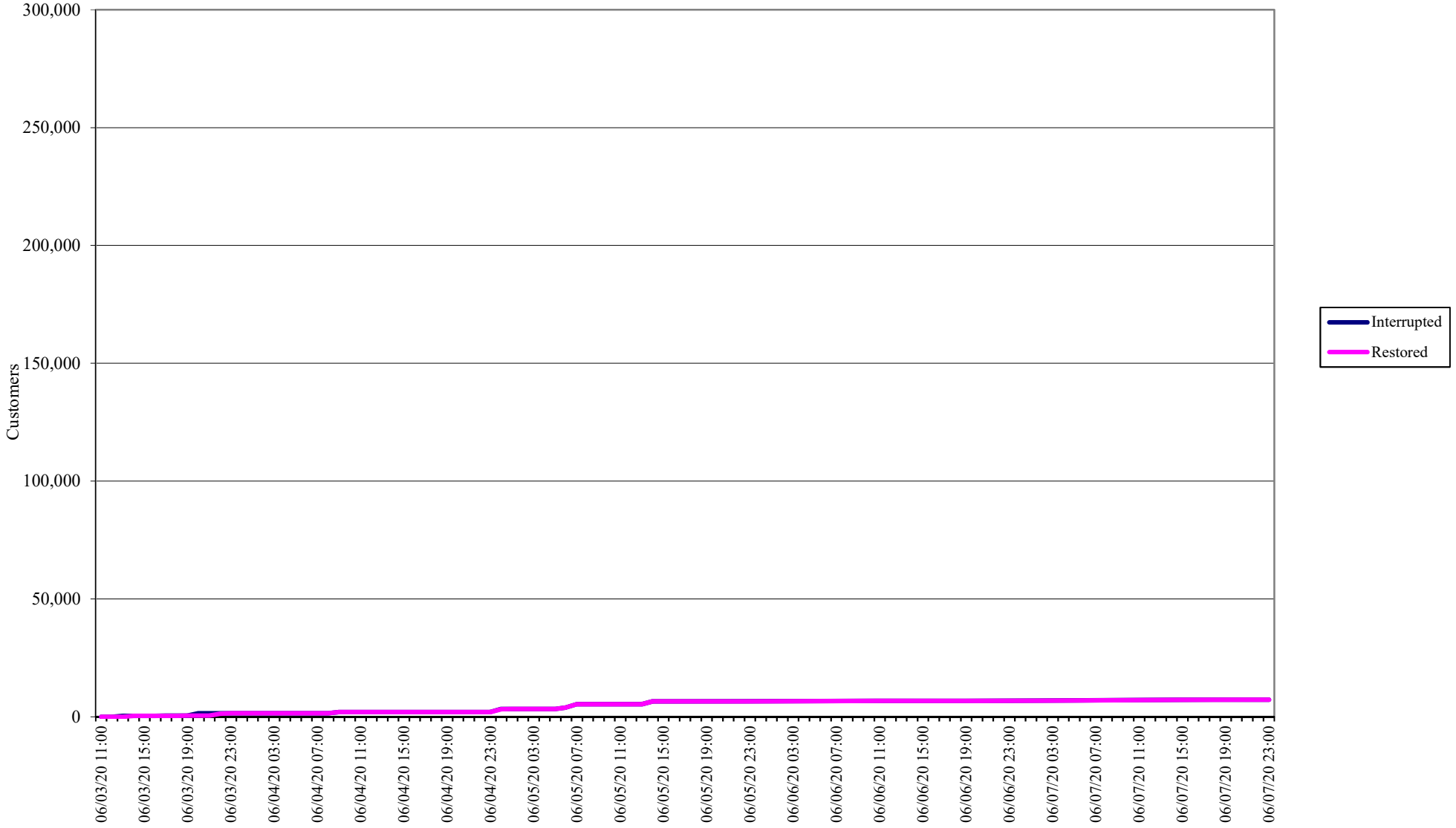
Attachment "B"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Central Division



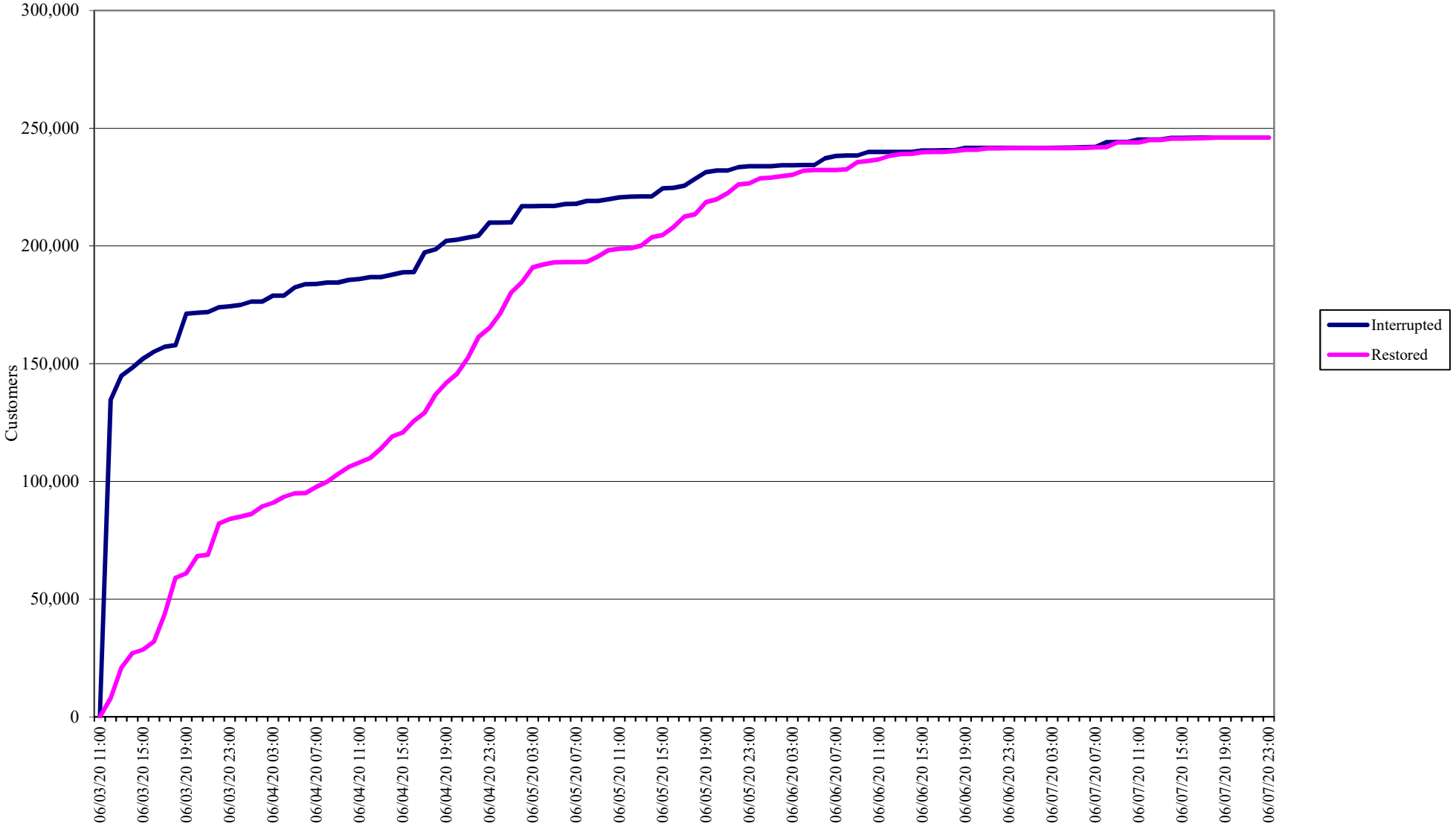
Attachment "C"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Metropolitan Division



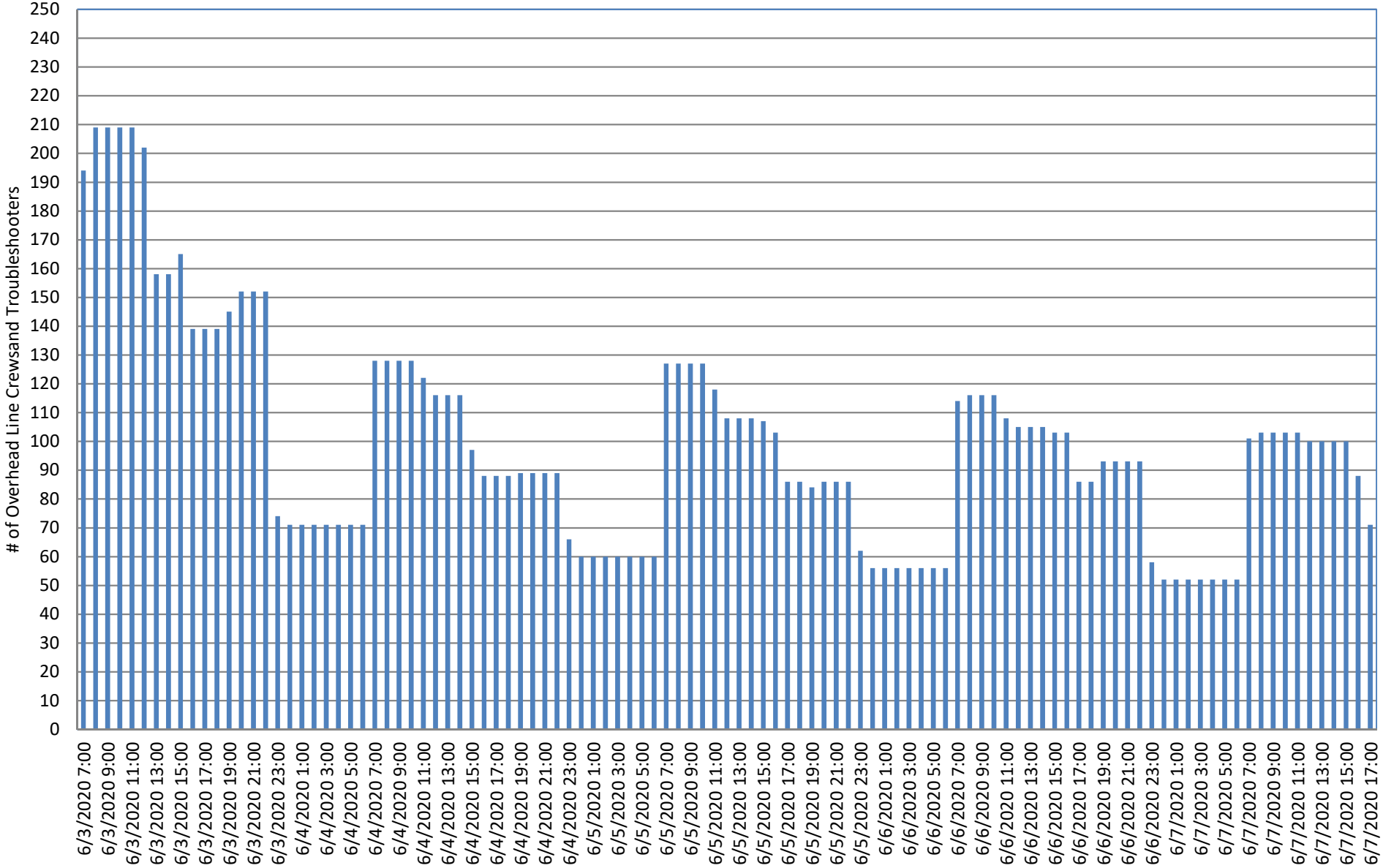
Attachment "D"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
Derecho and Severe Thunderstorms – June 3-7, 2020
Southern Division

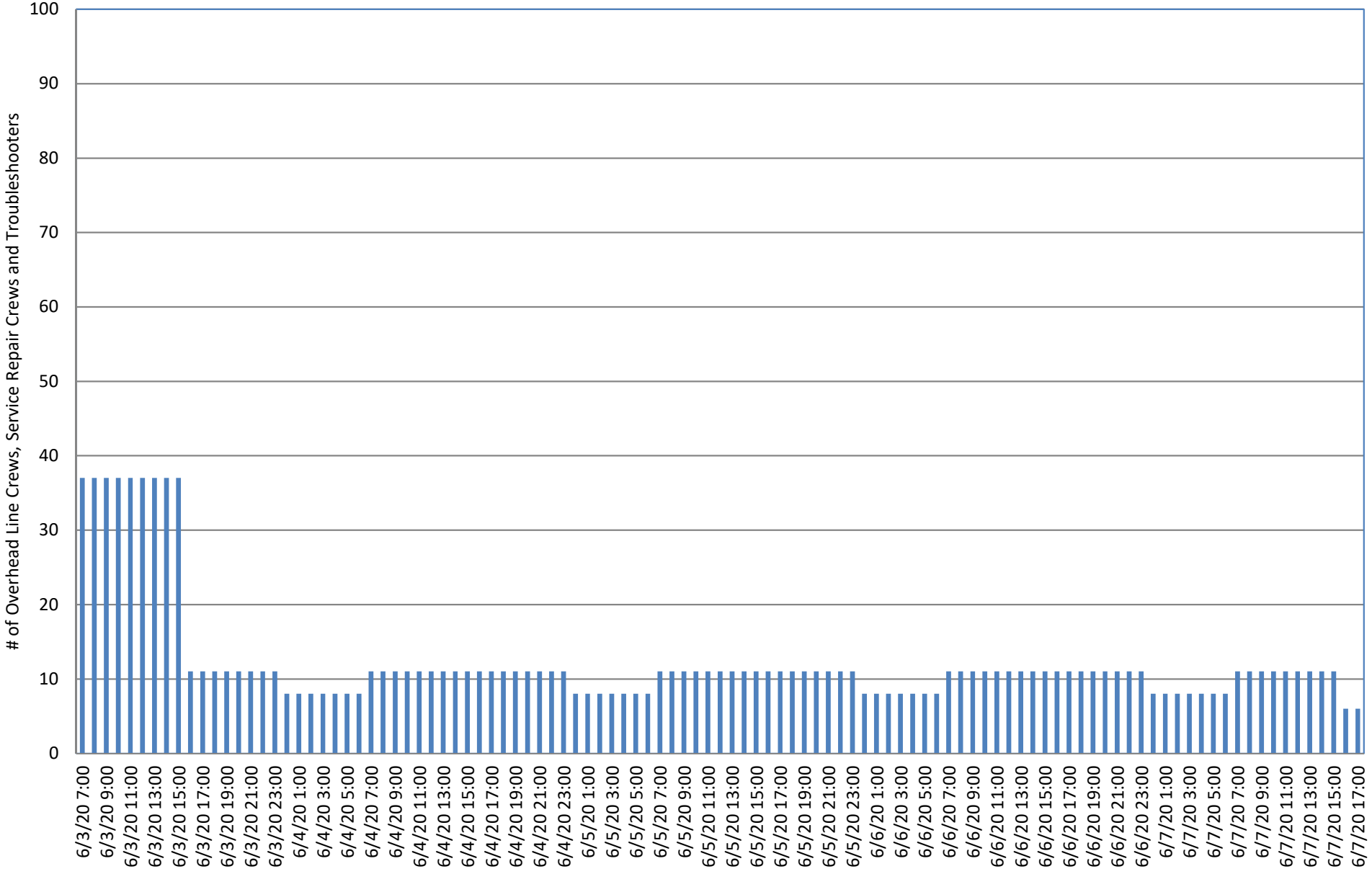


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
Derecho and Severe Thunderstorms - June 3-7, 2020

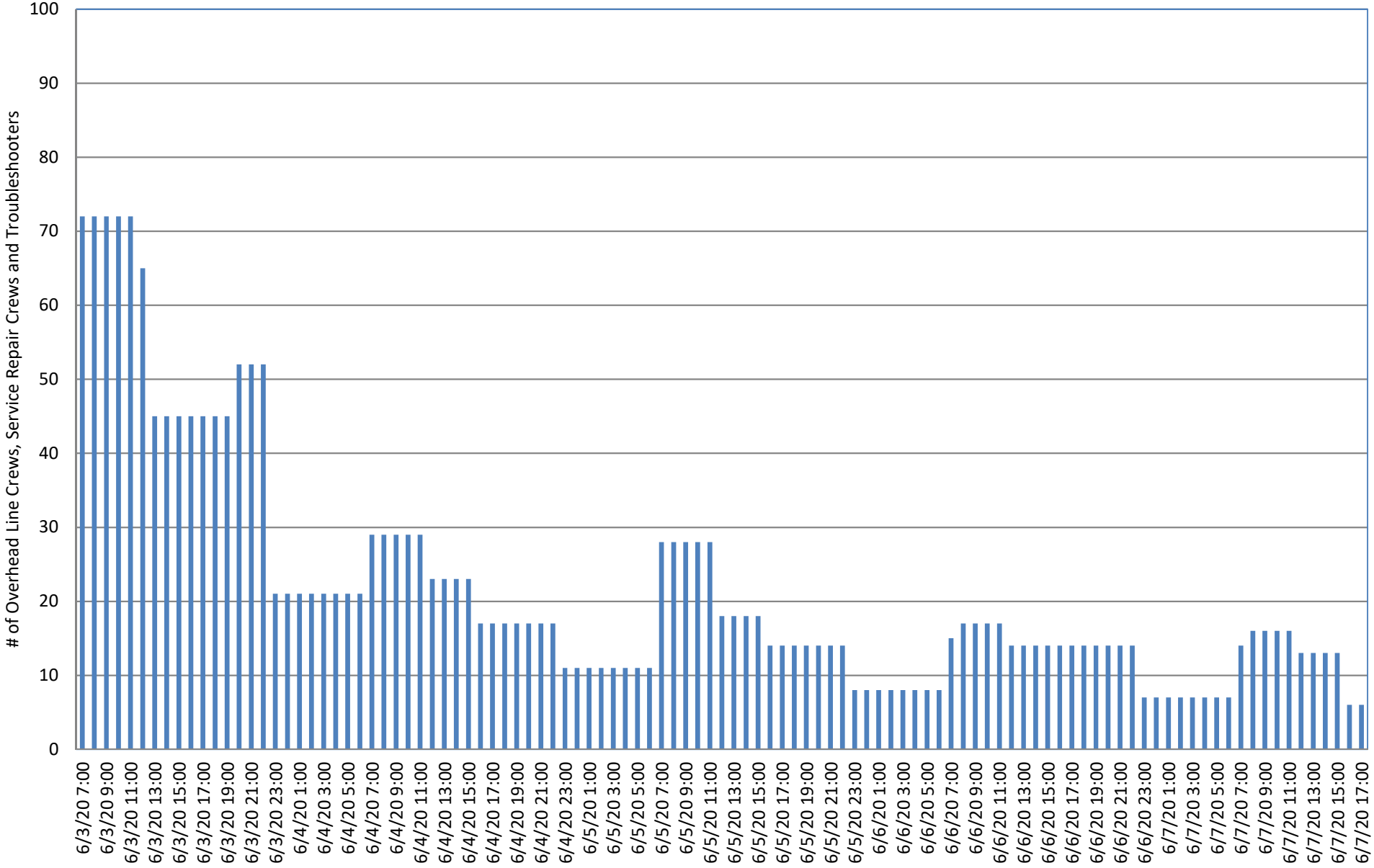


*These values include P&C Workforce Numbers

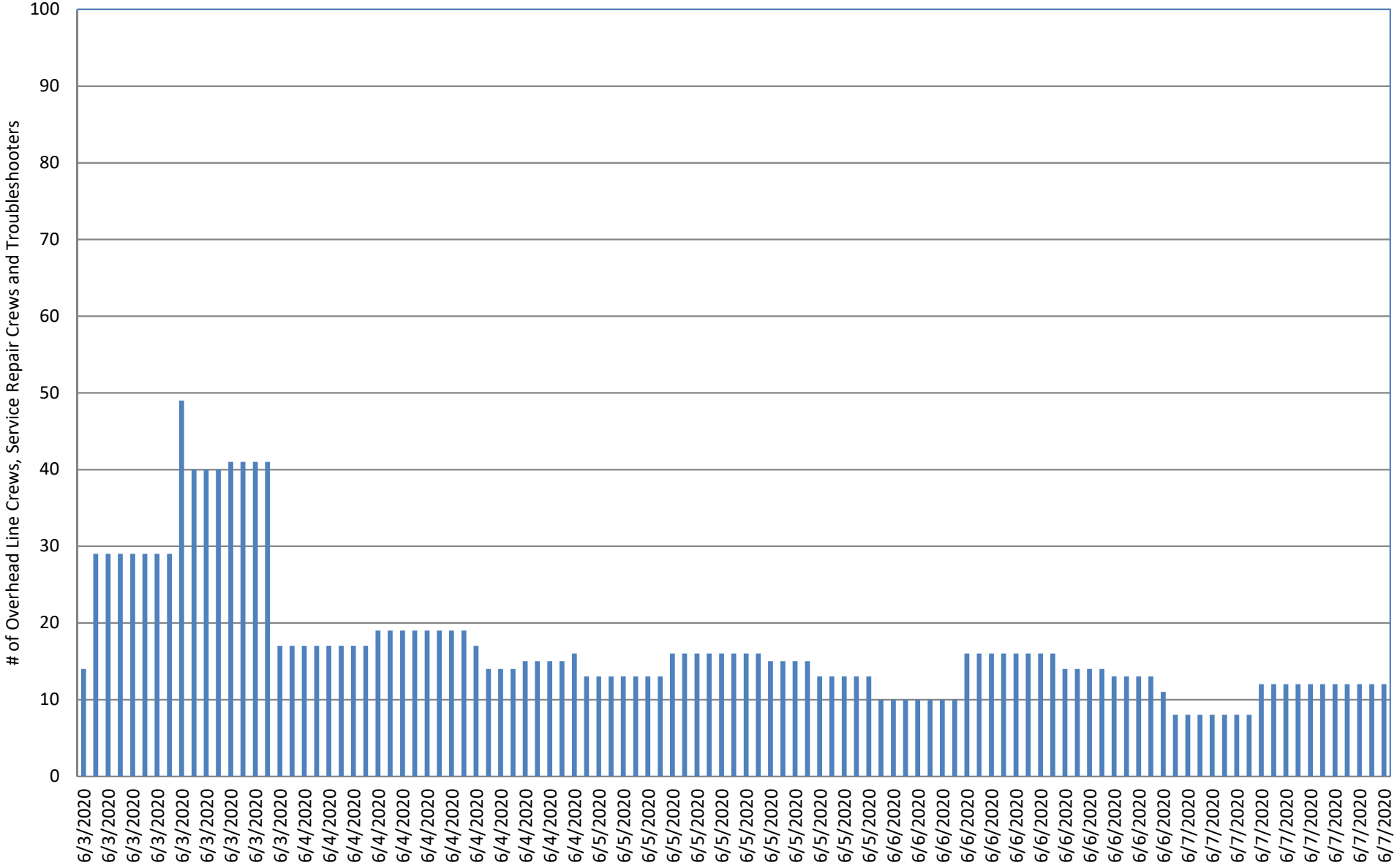
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
Derecho and Severe Thunderstorms - June 3-7, 2020



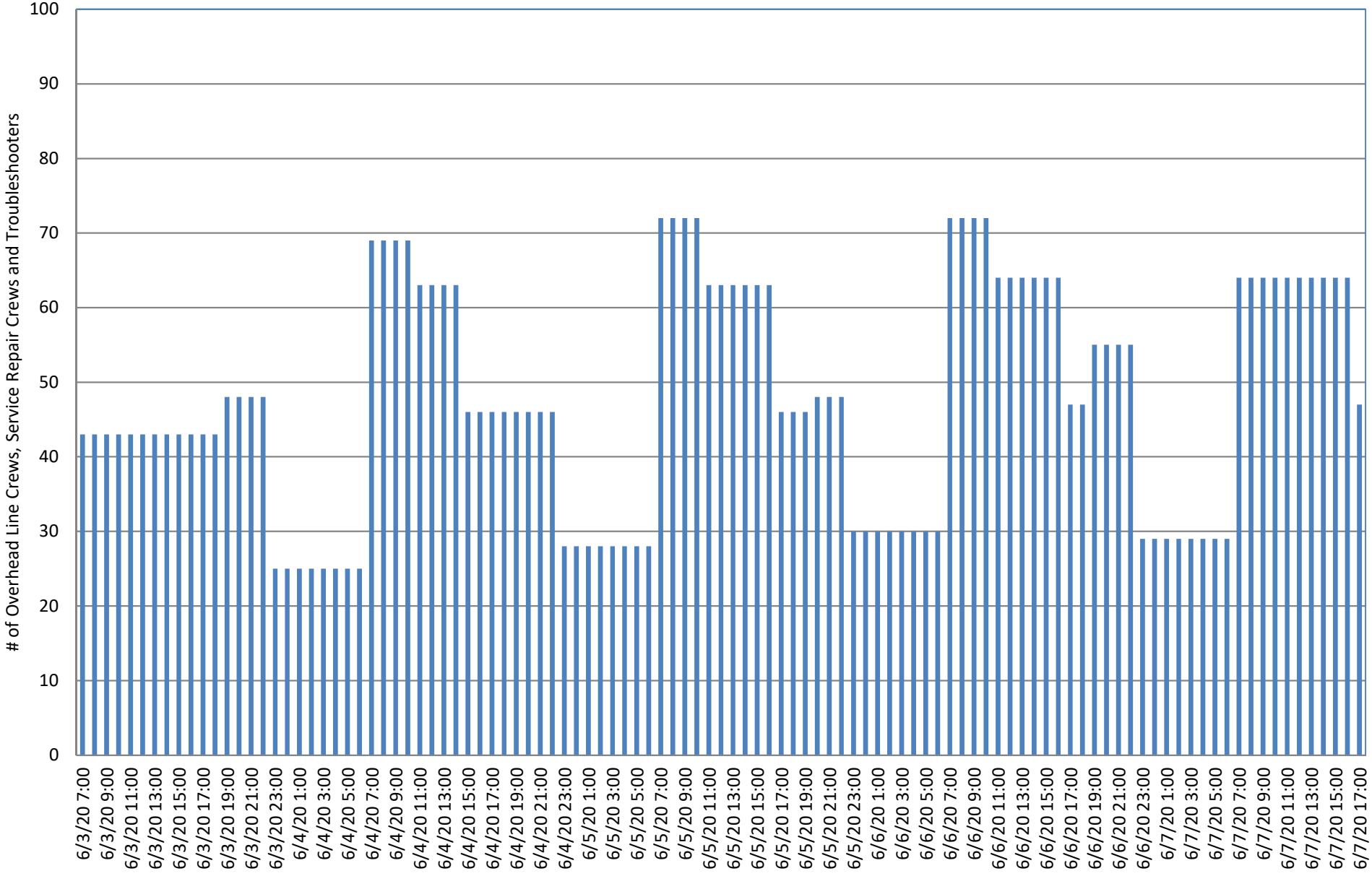
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
Derecho and Severe Thunderstorms - June 3-7, 2020



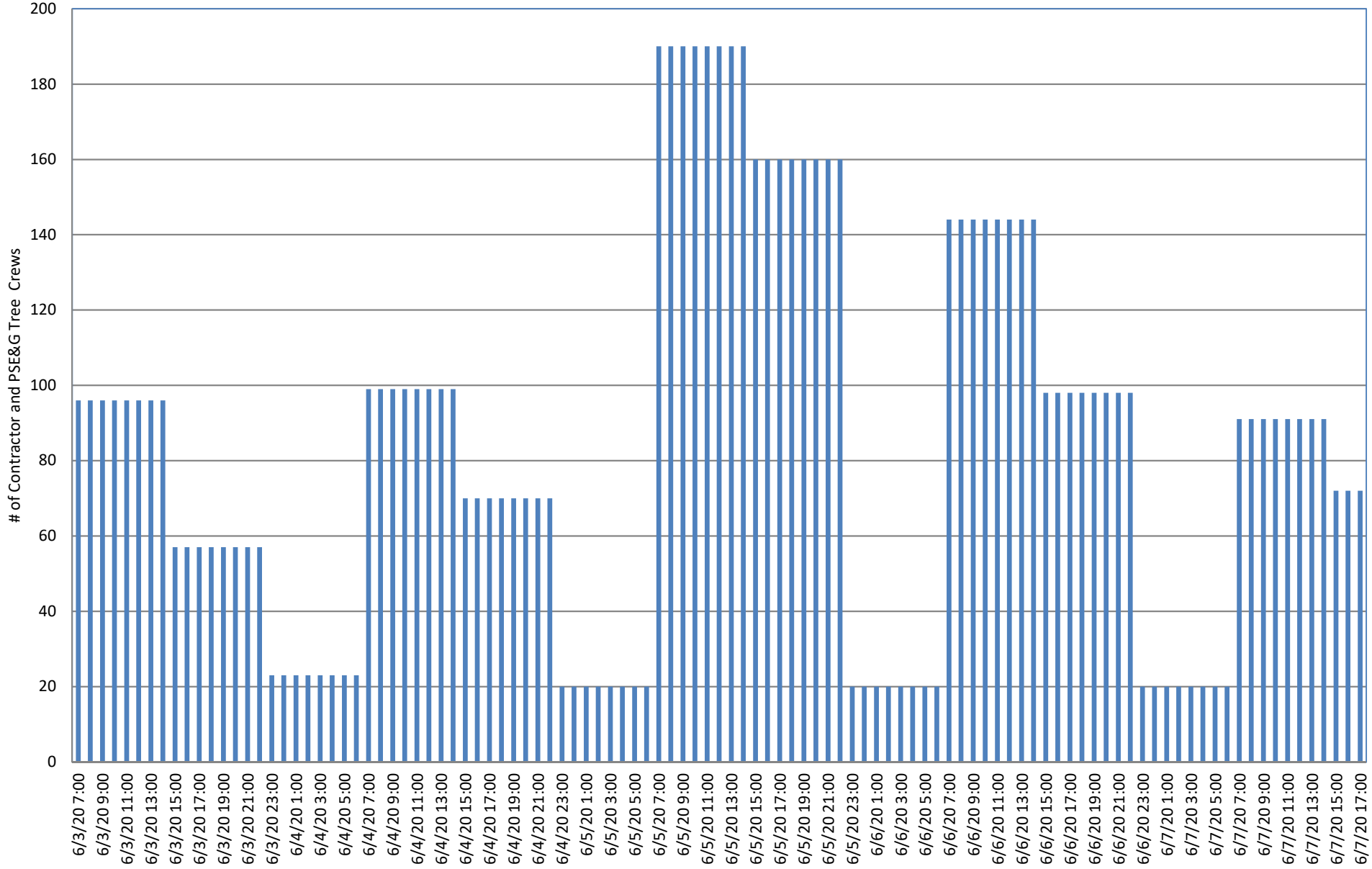
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
Derecho and Severe Thunderstorms - June 3-7, 2020



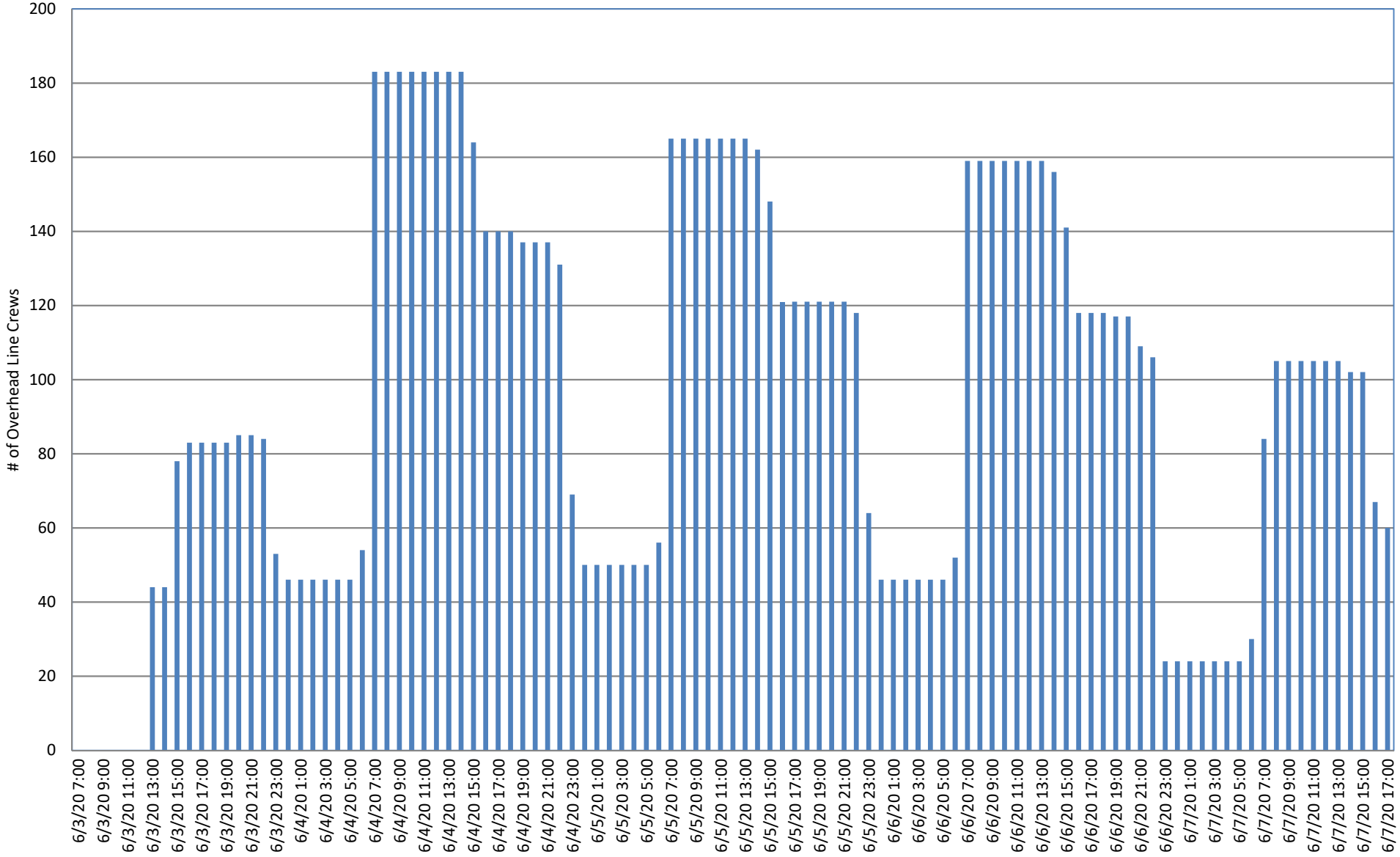
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
Derecho and Severe Thunderstorms - June 3-7, 2020

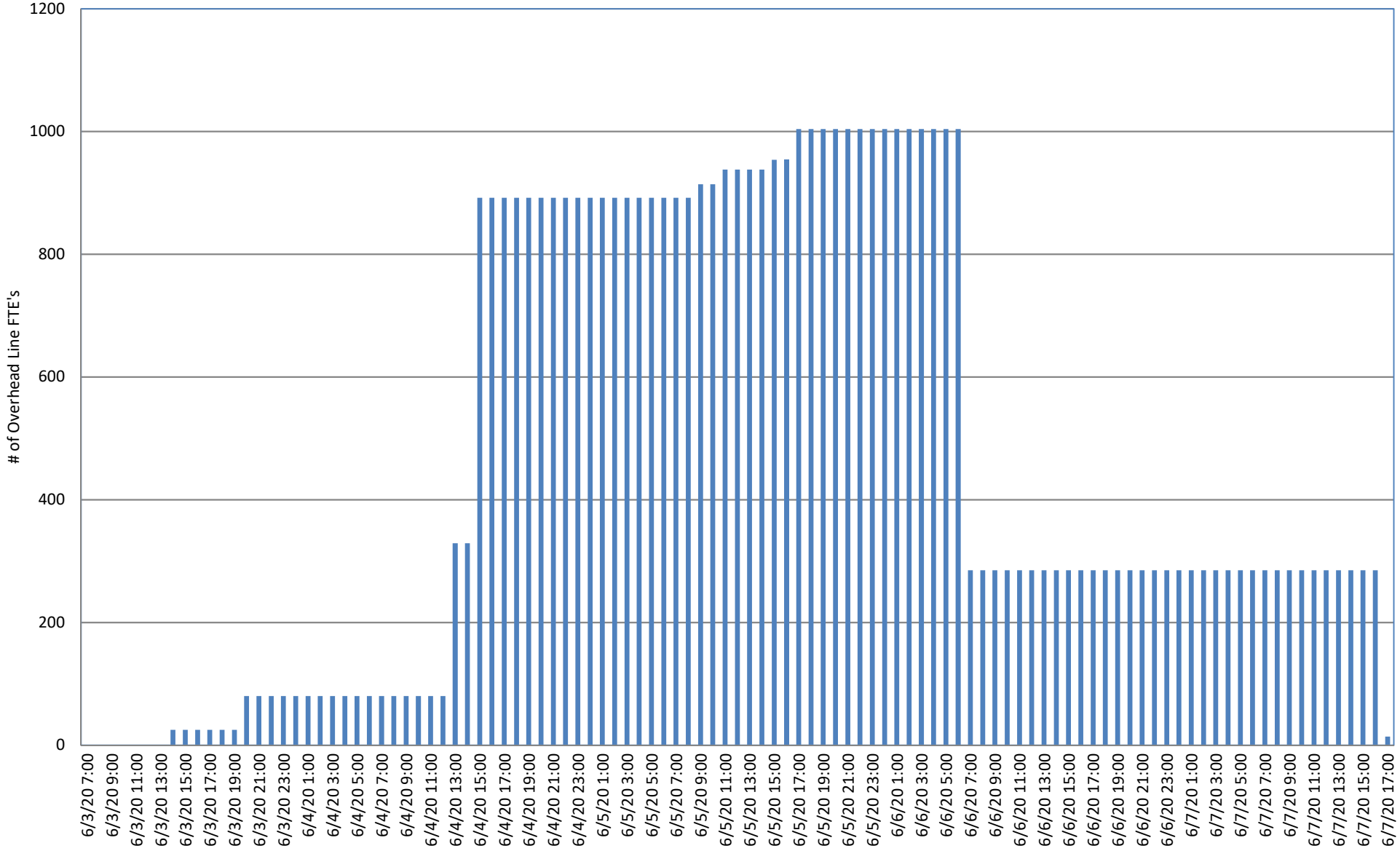


Attachment "L"
PSE&G
Overhead Line Crews, Service Repair Crews, Troubleshooters, Service Dispatchers and Substation Operators Assisting Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



*These values include P&C Workforce Numbers

Attachment "M"
PSE&G
Mutual Aid Line FTE's Assisting Southern Division
Derecho and Severe Thunderstorms - June 3-7, 2020



6/3 Storm
Electric Delivery

		Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**2,255,814**	**7,010,862**	**9,266,675**	**3,385,023**
2	Contractor/Mutual Aid	4,891,523	8,387,837	13,279,360	8,387,837
3	Tree Removal	600,928	1,728,426	2,329,354	1,728,426
4	Buses	-	-	-	-
5	Other Contractor	719,956	218,548	938,504	218,548
	Total Contractor	**6,212,408**	**10,334,811**	**16,547,218**	**10,334,811**
6	Material	**672,258**	**110,167**	**782,425**	**103,785**
7	Food	35,520	103,471	138,991	103,471
8	Lodging	245,142	693,380	938,522	693,380
9	Security	-	1,411	1,411	1,411
10	Water and Ice	-	159,895	159,895	159,895
14	Email Alerts	-	6,935	6,935	6,935
11	Other	64,529	185,943	250,473	4,318
	Total Other	**345,191**	**1,151,036**	**1,496,227**	**969,411**
	Total Incurred	**9,485,671**	**18,606,875**	**28,092,545**	**14,793,029**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**9,485,671**	**18,606,875**	**28,092,545**	**14,793,029**

Matthew M. Weissman
Managing Counsel - State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

March 16, 2021

Via Electronic Mail Only

Robert Brabston, Acting Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
STATE OF EMERGENCY - WINTER STORMS
JANUARY 31 - FEBRUARY 23, 2021

Dear Director Brabston:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the State of Emergency - Winter Storms that affected PSE&G's entire service territory from January 31 - February 23, 2021.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G'S REPORT TO THE BPU
MAJOR EVENT
STATE OF EMERGENCY - WINTER STORMS
JANUARY 31 - FEBRUARY 23, 2021

EXECUTIVE SUMMARY

PSE&G's entire service territory was affected by a series of winter storms from January 31 to February 23, 2021. These winter storms began with a heavy snowstorm on February 1 - 2, which deposited up to 24" of snow in portions of the service territory. Subsequent storms during this period caused snow, sleet and freezing rain to fall over the entire service territory. Governor Phil Murphy declared a State of Emergency (SOE) on January 31 at 1900 hrs. The SOE was lifted on February 23 at 1700 hrs. There were 104,932 customers that experienced extended interruptions during these weather events.

PSE&G began preparing for the predicted heavy February 1 - 2 snowstorm on January 29 on its 0800 hrs. operations conference call. Extra line crews and support personnel were scheduled throughout the weekend and the 72/48/24 hour storm preparation checklists were scheduled to be reviewed. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

On January 29, PSE&G contacted contractors for the availability of Line FTEs. Commitments for 68 Line FTEs were obtained with the individuals scheduled to leave for PSE&G at 0700 hrs. on February 1. They arrived later that day. Their services were not required and they were released at 0800 hrs. on February 3. In addition, 40 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

On February 13, PSE&G was able to secure 29 contractor Line FTEs that arrived on February 14. Their services were not required and they were released on February 16. In addition, 35 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

A remote reporting site for the foreign crews was established at PSE&G's Hadley Road location in South Plainfield.

PSE&G opened its Emergency Operations Center (EOC) on February 1 at 0830 hrs. It remained open in a virtual mode until 0830 hrs. on February 2. This was the only time during this series of winter storms that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on February 1. Liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on January 29 and continued until February 23.

OPERATING REPORT

There were 104,932 customers that experienced extended interruptions during these weather events as listed below:

Division	# Customers Interrupted	Final Restoration
Central	21,822	2/22 - 1628 hrs.
Metropolitan	26,508	2/23 - 1430 hrs.
Palisades	27,213	2/23 - 1427 hrs.
Southern	29,289	2/23 - 1017 hrs.
Total	104,932	

Attached are the following Customer Restoration Summary Graphs for these weather events:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

PSE&G's entire service territory was affected by a series of winter storms from January 31 to February 23, 2021. These winter storms began with a heavy snowstorm on February 1 - 2, which deposited up to 24" of snow in portions of the service territory. Subsequent storms during this period caused snow, sleet and freezing rain to fall over the entire service territory. Governor Phil Murphy declared a State of Emergency (SOE) on January 31 at 1900 hrs. The SOE was lifted on February 23 at 1700 hrs. There were 104,932 customers that experienced extended interruptions during these weather events.

PSE&G began preparing for the predicted heavy February 1 - 2 snowstorm on January 29 on its 0800 hrs. operations conference call. Extra line crews and support personnel were scheduled throughout the weekend and the 72/48/24 hour storm preparation checklists were scheduled to be reviewed. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

On January 29, PSE&G contacted contractors for the availability of Line FTEs. Commitments for 68 Line FTEs were obtained with the individuals scheduled to leave for PSE&G at 0700 hrs. on February 1, they arrived later that day. Their services were not required and they were released at 0800 hrs. on February 3. In addition, 40 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

On February 13, PSE&G was able to secure 29 contractor Line FTEs that arrived on February 14. Their services were not required and they were released on February 16. In addition, 35 contractor Line FTEs that were already on PSE&G's property were also available for storm restoration work.

A remote reporting site for the foreign crews was established at PSE&G's Hadley Road location in South Plainfield.

PSE&G opened its Emergency Operations Center (EOC) on February 1 at 0830 hrs. It remained open in a virtual mode until 0830 hrs. on February 2. This was the only time during this series of winter storms that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on February 1. Liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on January 29 and continued until February 23.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for these weather events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Mutual Aid Contractor Line FTEs

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning on February 1. This remote support continued until February 23. Remote liaison support was provided to the two Inquiry Centers during these weather events. These liaisons assisted on addressing customer inquiries.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	41
13 & 4-kV	-	419
Transformers	-	50
Secondaries	-	5
Services	-	26
Poles	-	73
Trees	-	20
Total	-	634

COMMUNICATIONS

Communications with Board staff began on January 29 and continued until February 23.

PSEG's Corporate Communications Department issued internal communication press releases and handled newspapers, television and radio information requests during these weather events.

PSE&G proactively utilized Social Media (Facebook, Twitter and LinkedIn) to communicate storm restoration information to customers during these weather events releasing 65 different messages. In addition, 5.3 Million emails were sent to customers during this weather event informing them of storm restoration progress.

As required in Recommendation 3 from the Tropical Storm Isaias Board Order, the following standardized Call Center information is provided:

Date	Number of calls Offered (NCO)	Number of calls Handled (NCH)	Number of call Abandoned (NCA)	Call abandonment rate (CA %)	Average speed of answer (ASA)
1/31/2021	7994	7921	73	0.9%	9.0
2/1/2021	22413	22258	155	0.7%	2.5
2/2/2021	17831	17715	116	0.7%	1.3
2/3/2021	22134	21710	424	1.9%	27.4
2/4/2021	21411	20818	593	2.8%	48.8
2/5/2021	23545	22341	1204	5.1%	102.2
2/6/2021	11355	11160	195	1.7%	13.9
2/7/2021	6158	6106	52	0.8%	2.2
2/8/2021	26646	25347	1299	4.9%	104.9
2/9/2021	22665	21691	974	4.3%	88.9
2/10/2021	21282	20717	565	2.7%	42.7
2/11/2021	22508	20622	1886	8.4%	82.7
2/12/2021	19509	19120	389	2.0%	33.1
2/13/2021	10697	10545	152	1.4%	5.0
2/14/2021	5785	5745	40	0.7%	1.7
2/15/2021	18619	18308	311	1.7%	12.9
2/16/2021	28101	26008	2093	7.4%	176.2
2/17/2021	22721	21493	1228	5.4%	113.3
2/18/2021	20398	19938	460	2.3%	32.9
2/19/2021	20545	20356	189	0.9%	2.6
2/20/2021	10541	10416	125	1.2%	1.9
2/21/2021	6213	6157	56	0.9%	1.5
2/22/2021	26979	25602	1377	5.1%	99.2
2/23/2021	22072	21011	1061	4.8%	91.9

Notifications to PSE&G's critical needs (P-4) customers were issued on January 31, February 13, 15 and 17 informing them of the impending storms and recommending precautions they should take. This information was also included in outbound calls made with Estimated Times of Restoration (ETRs).

Conference calls with mayors and other municipal and elected officials were held on February 1 and February 18 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

A North Atlantic Mutual Assistance Group (NAMAG) conference call was held on February 1 at 1300 hrs. On the call, utilities in New England requested assistance. Another conference call was held on February 14 at 1800 hrs. where again utilities in New England requested assistance. PSE&G did not offer any assistance on either call.

INCIDENTS

Service to Ellis Island was interrupted on February 1 at 1510 hrs. and was restored on February 3 at 0033 hrs. The interruption was caused by snow entering the customer's switchgear. PSE&G personnel worked with Ellis Island personnel in resolving the problem.

On February 19 at 1233 hrs., 345-kV circuit F-3432 locked out. Investigation revealed that falling ice from an "A" frame at Bayway Switching Station contacted equipment on a portion of the station's 345-kV bus. The 345-kV bus was cleaned and the circuit was restored to service on February 21 at 2050 hrs.

On February 20 at 0955 hrs., 345-kV circuit S-3419 locked out. Investigation revealed flash marks on a 345-kV lightning arrester at the circuit's North Avenue Substation terminal. The lightning arrester was found to be ice covered and contaminated with road sand, apparently from snow plowing activities on nearby North Avenue. The lightning arrester was cleaned and the circuit was restored to service on February 21 at 1113 hrs.

SUMMARY

Restoration effects during these weather events went extremely well. PSE&G was well prepared to address the outages caused by the winter weather. There were 104,932 customers that experienced extended interruptions during these weather events.

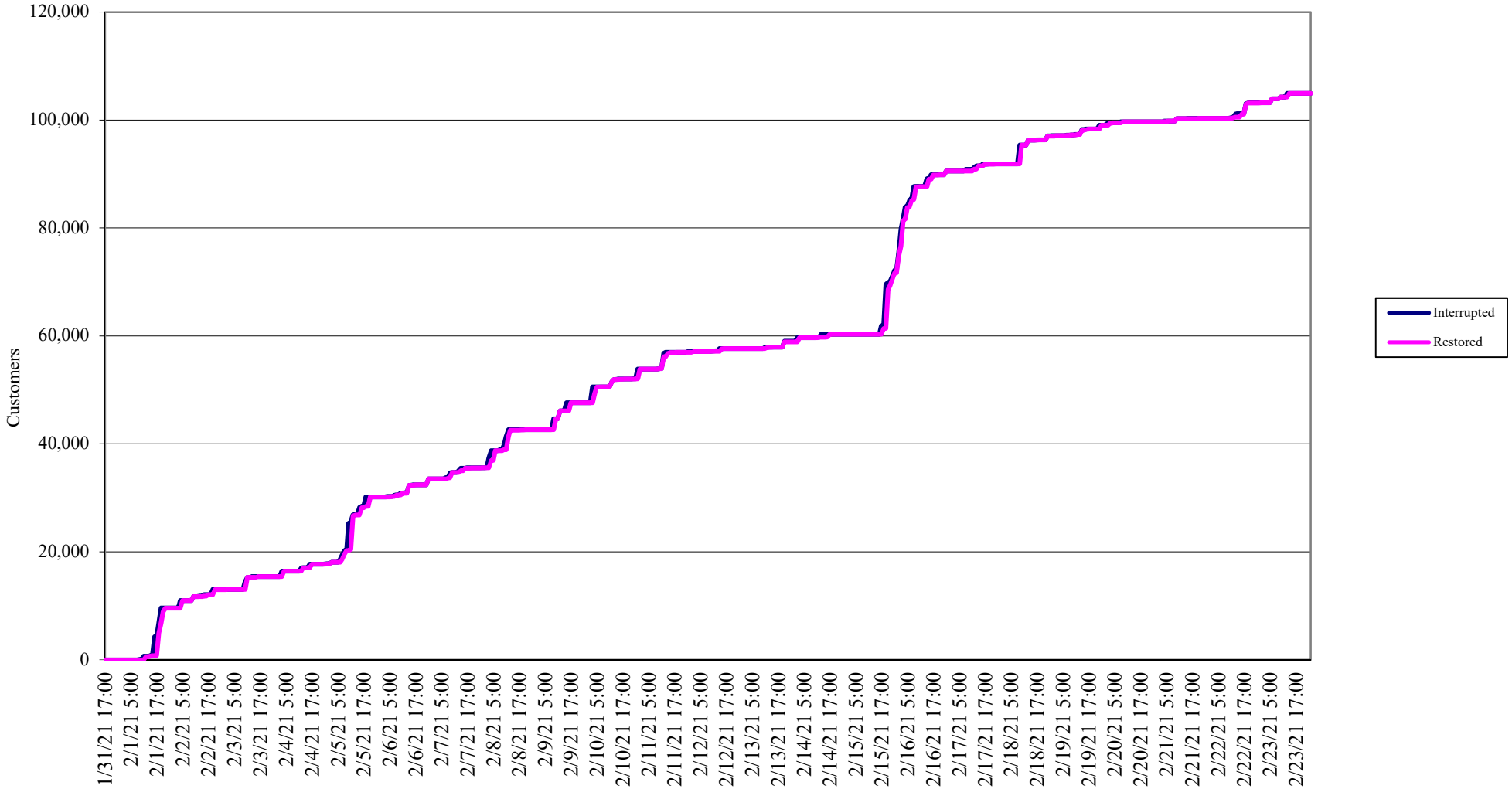
PSE&G excellent relationships with its unions were beneficial during these weather events.

There were no issues involving equipment or material during these weather events.

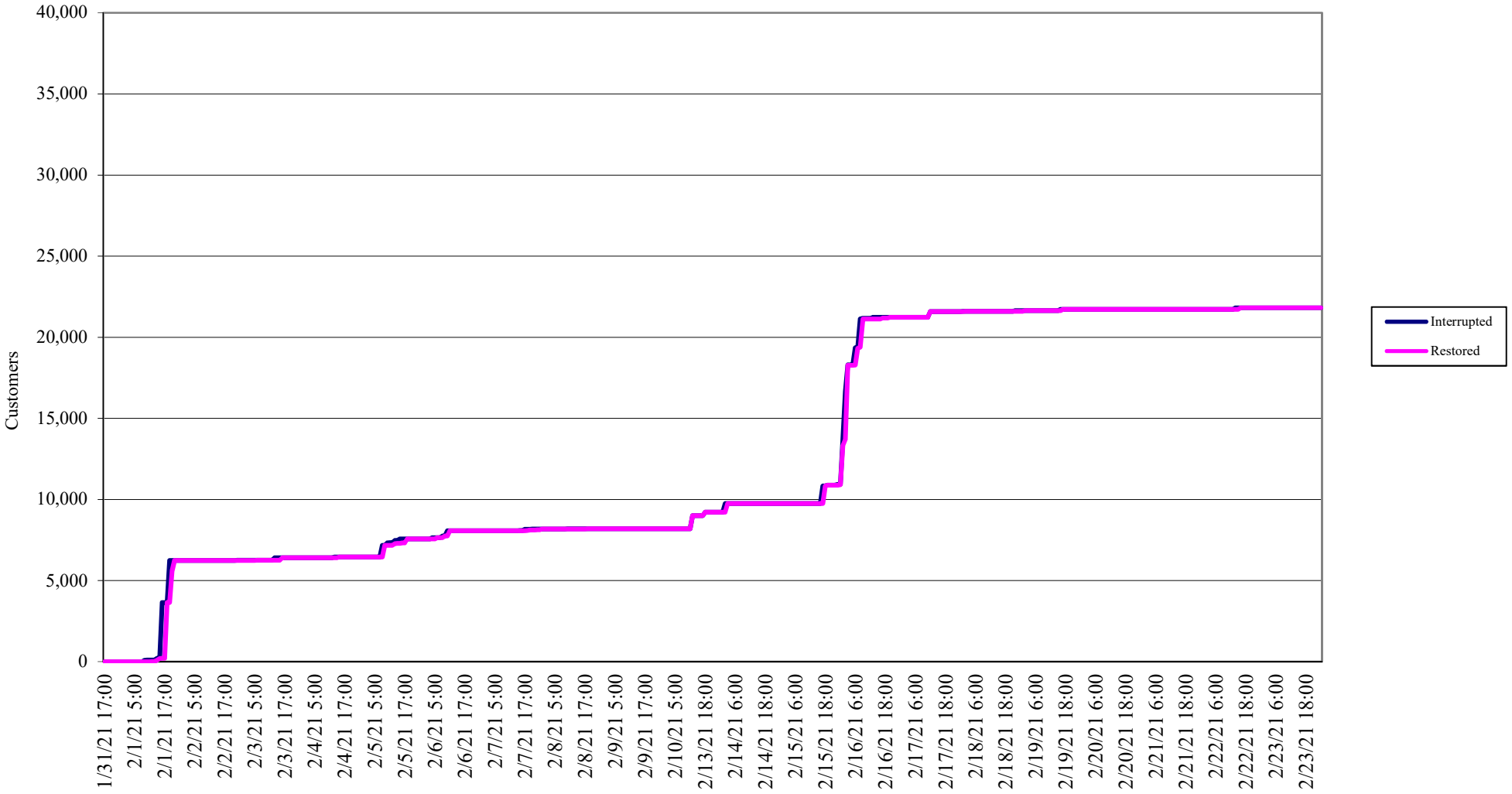
As required in Recommendation 11 from the Tropical Storm Isaias Board Order, a review of past storms revealed that these weather events were somewhat similar to winter weather events that affected PSE&G's service territory during the period February 3 - 14, 2014 when 139,249 customers experienced extended interruptions. The resiliency projects completed in PSE&G's Energy Strong I program and those that are currently underway in PSE&G's Energy Strong II program all contribute to improved reliability both during blue sky days and during Major Events. Comprehensive, comparison resiliency data involving Major Events is reported quarterly by PSE&G to the Independent Monitor as part of PSE&G's Energy Strong II Program, as it was during the Energy Strong I Program. The data referencing the weather events during the period January 31-February 23, 2021 will be submitted in PSE&G's First Quarter 2021 Energy Strong II Program Report.

DWW: bmc
3/10/21

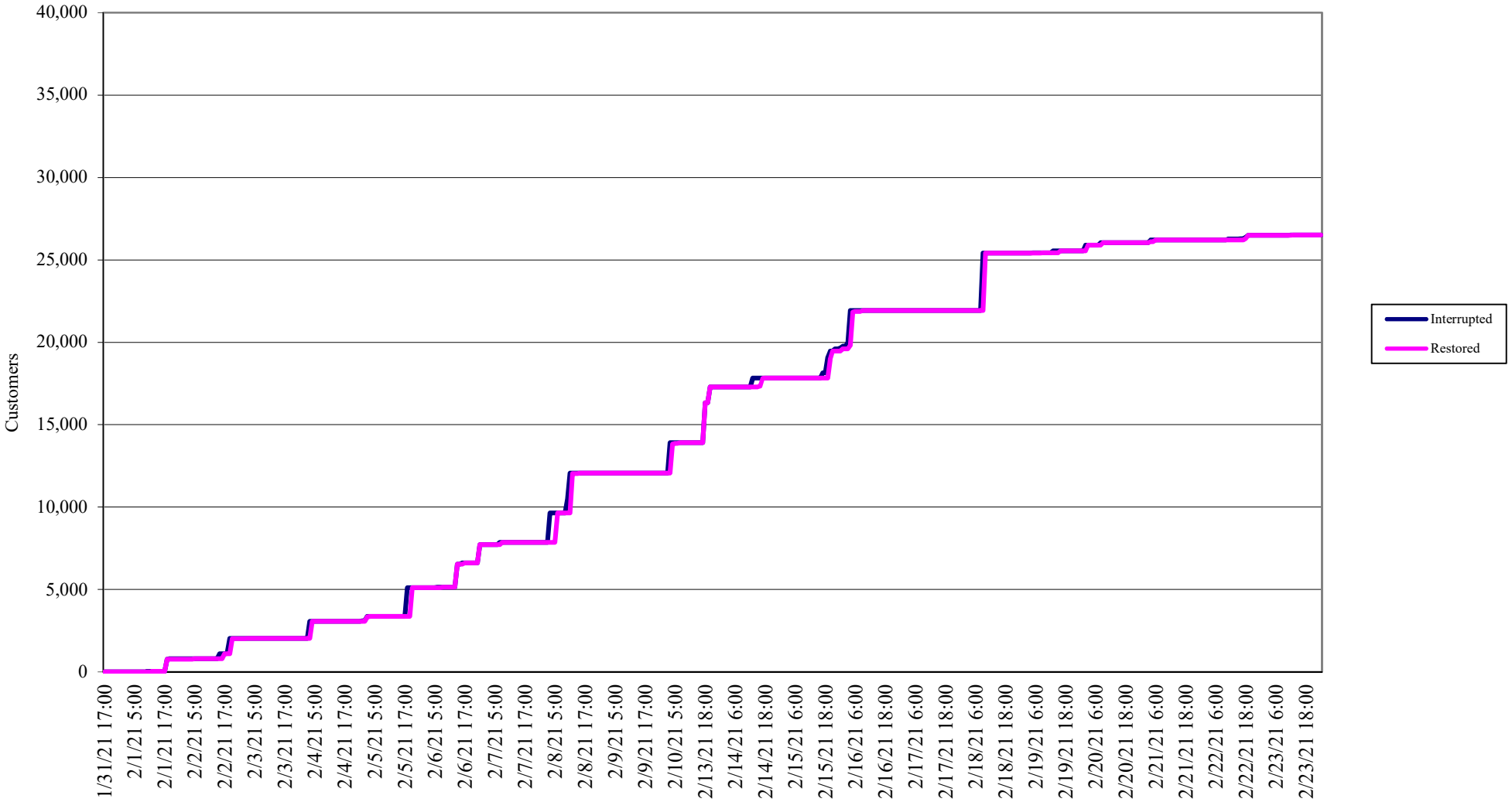
Attachment "A"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Company Wide



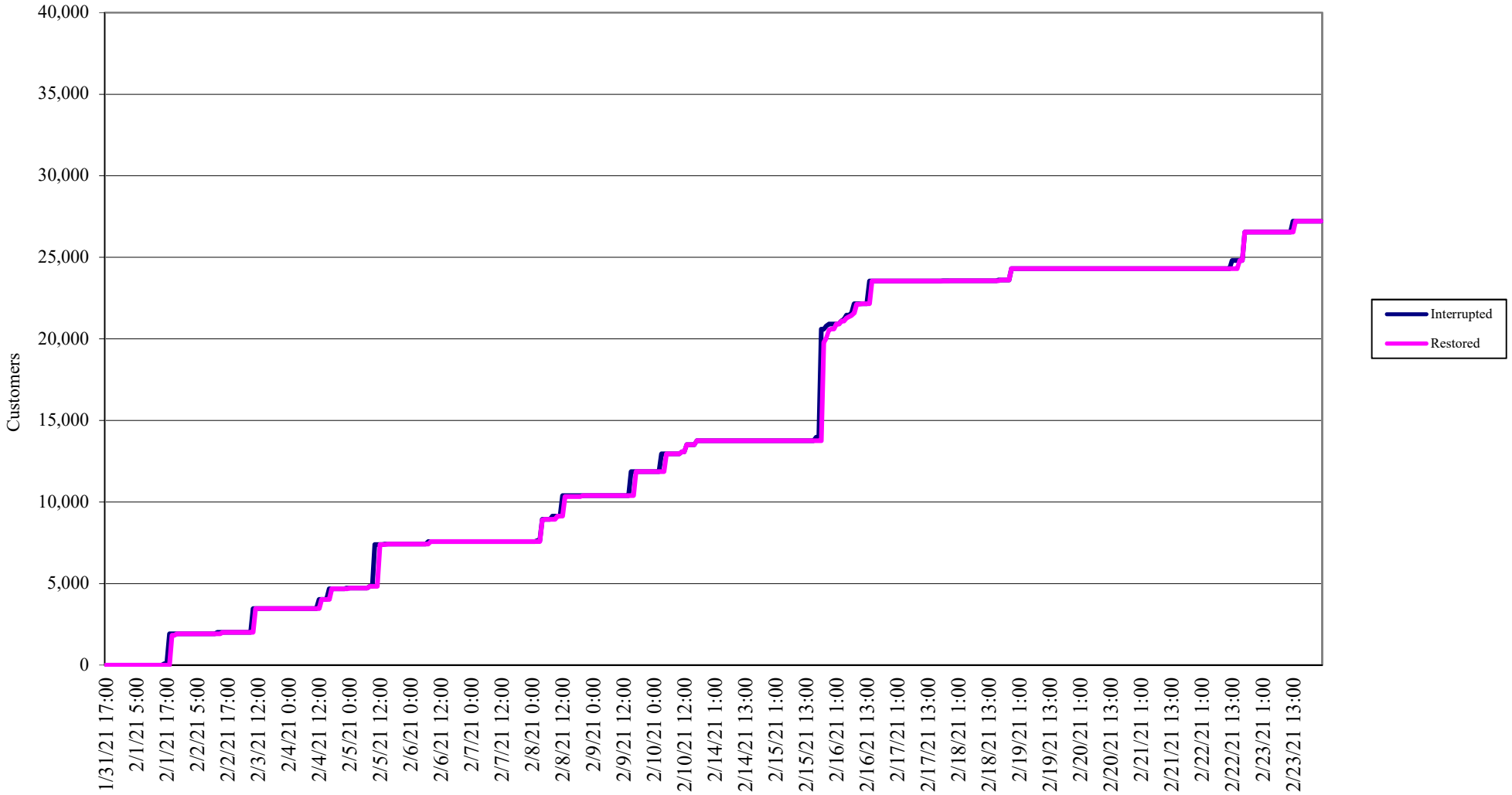
Attachment "B"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Central Division



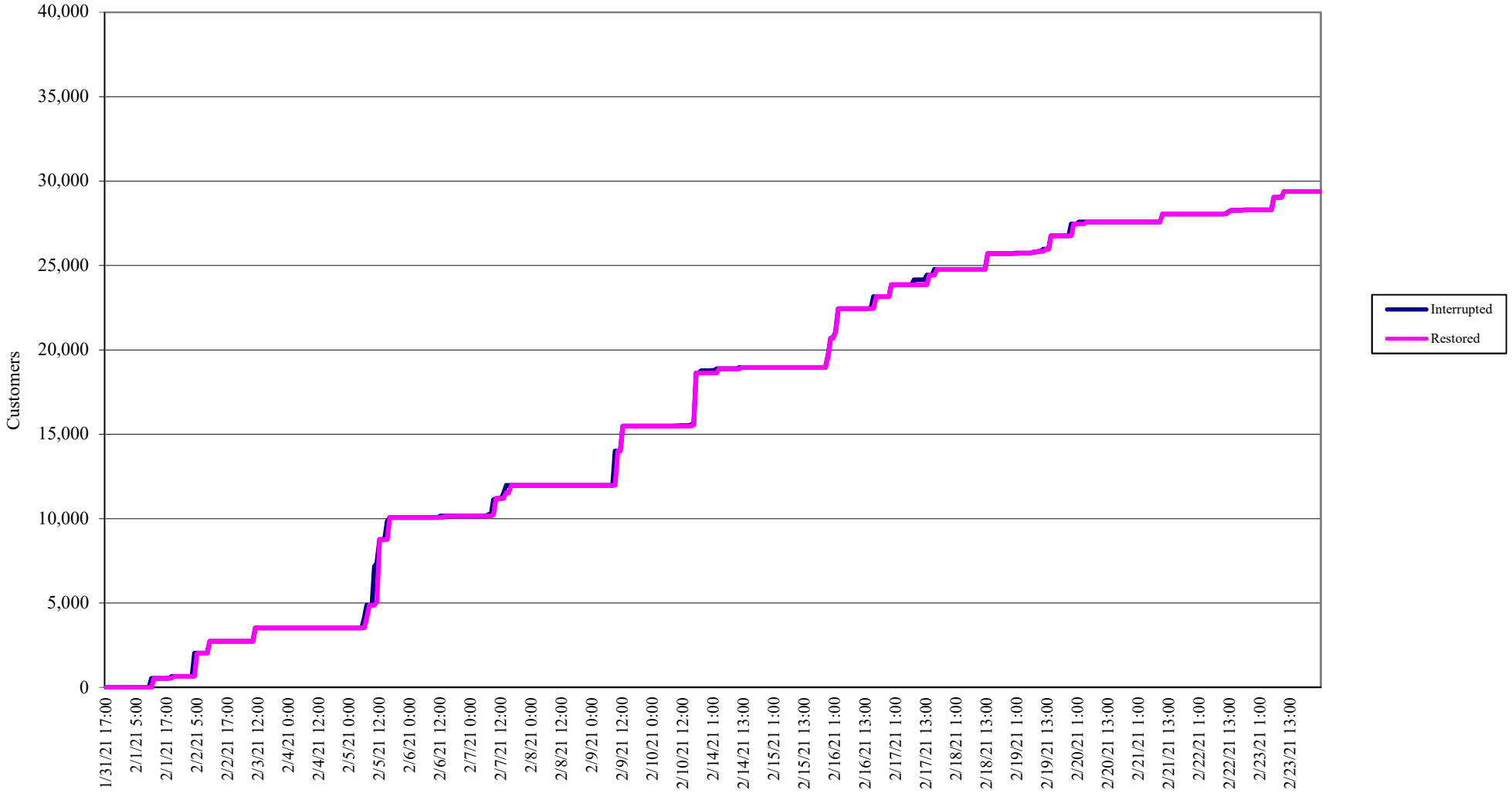
Attachment "C"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Metropolitan Division



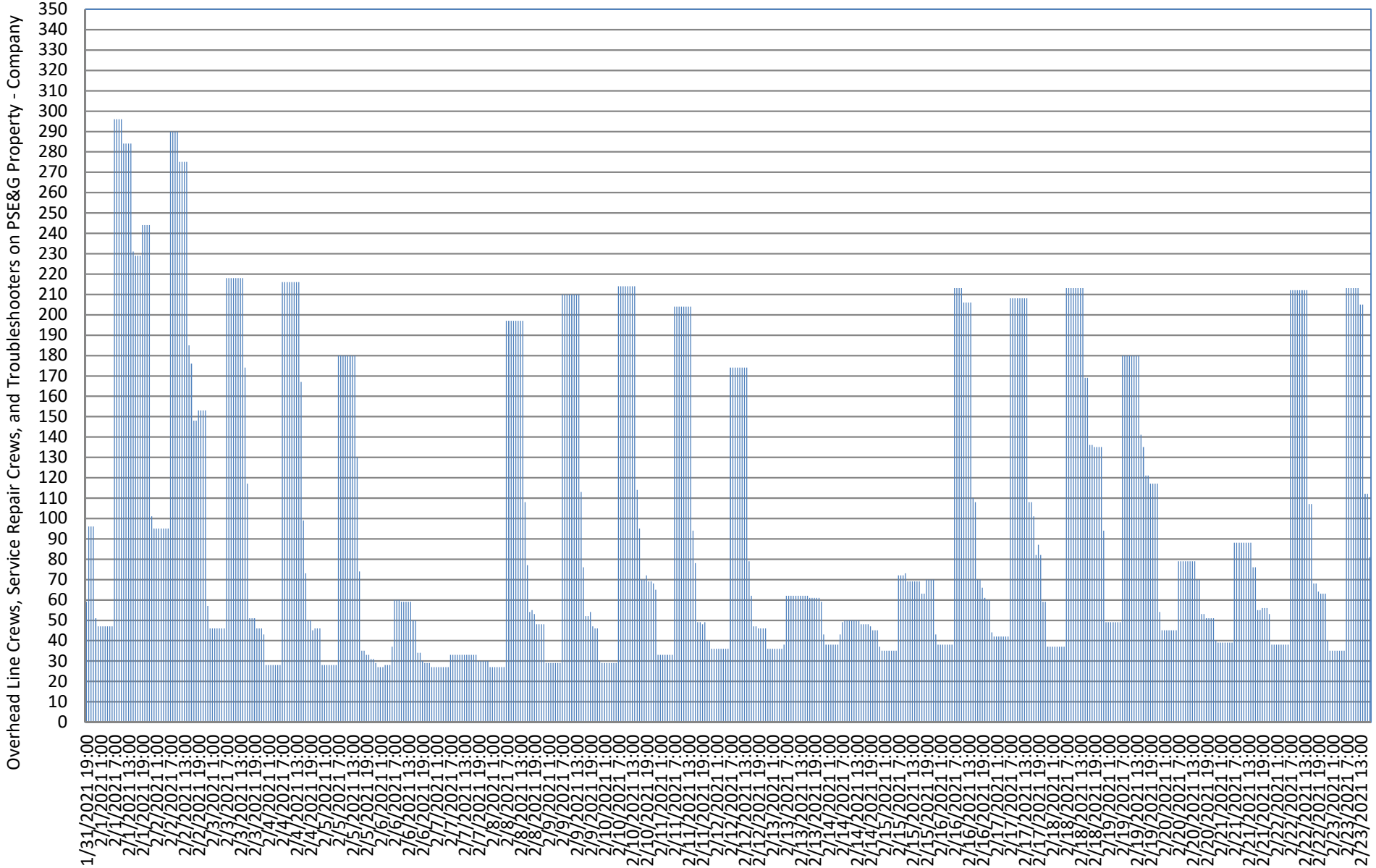
Attachment "D"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021
Southern Division

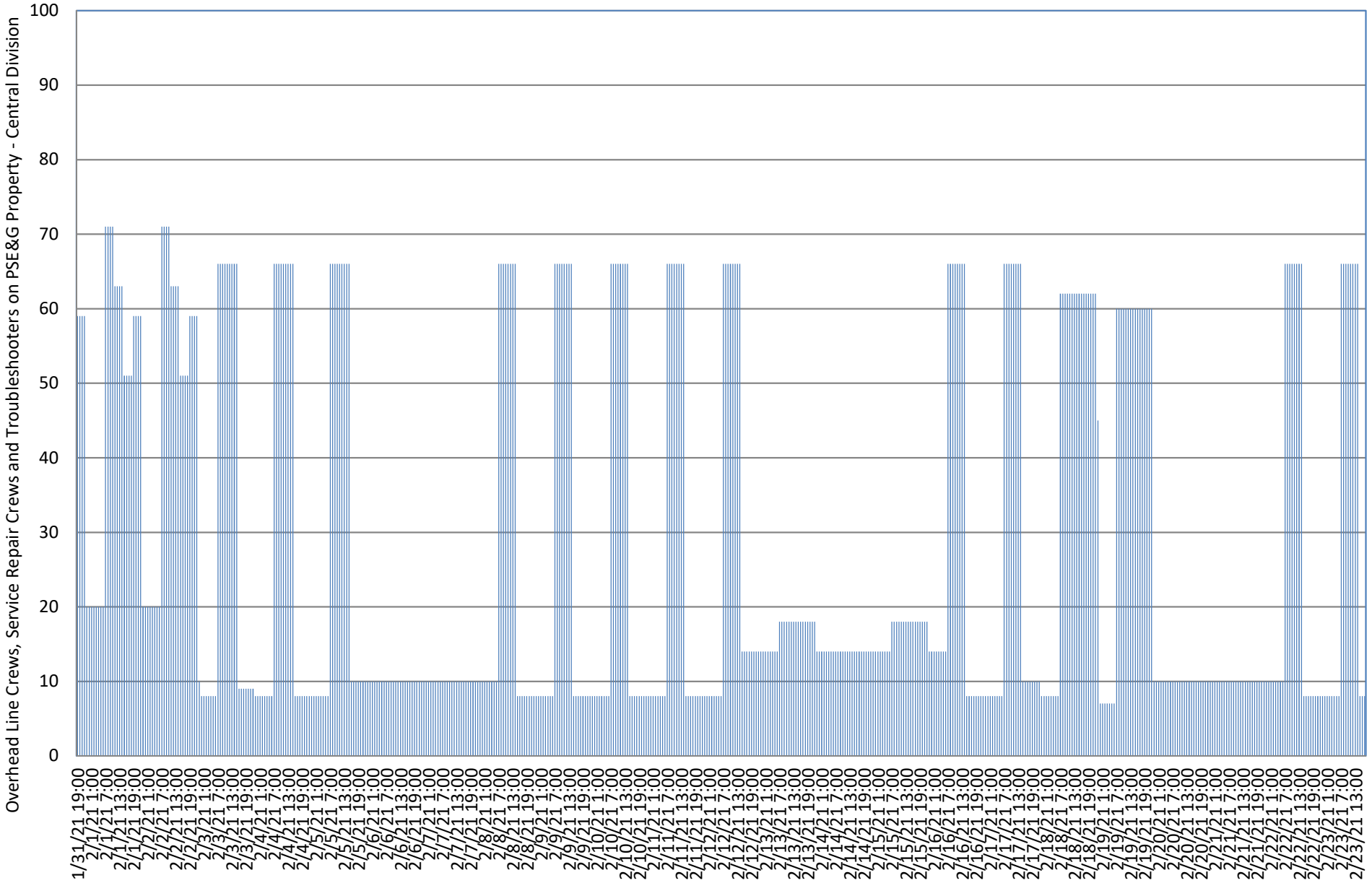


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021

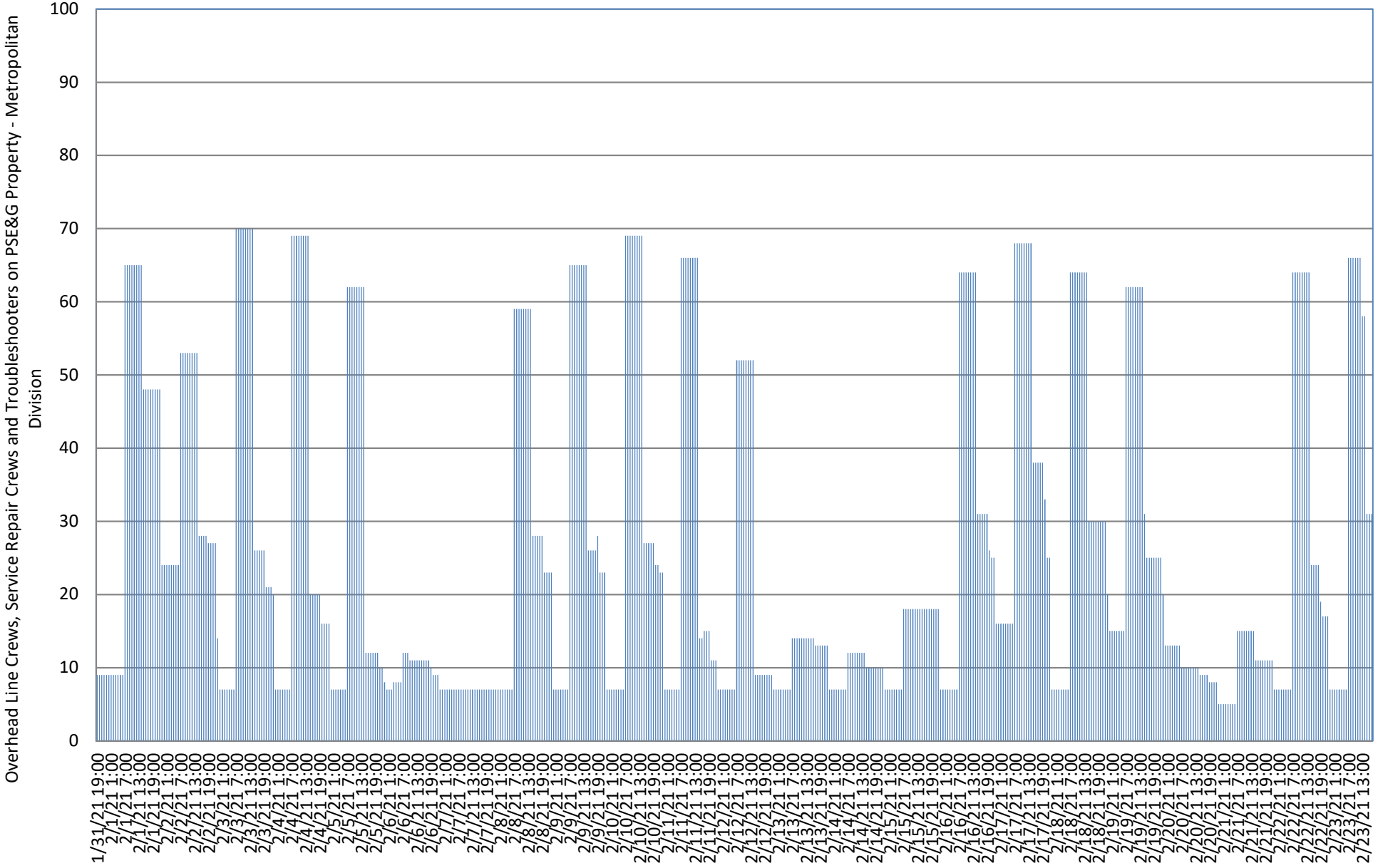


*These values include P&C Workforce Numbers

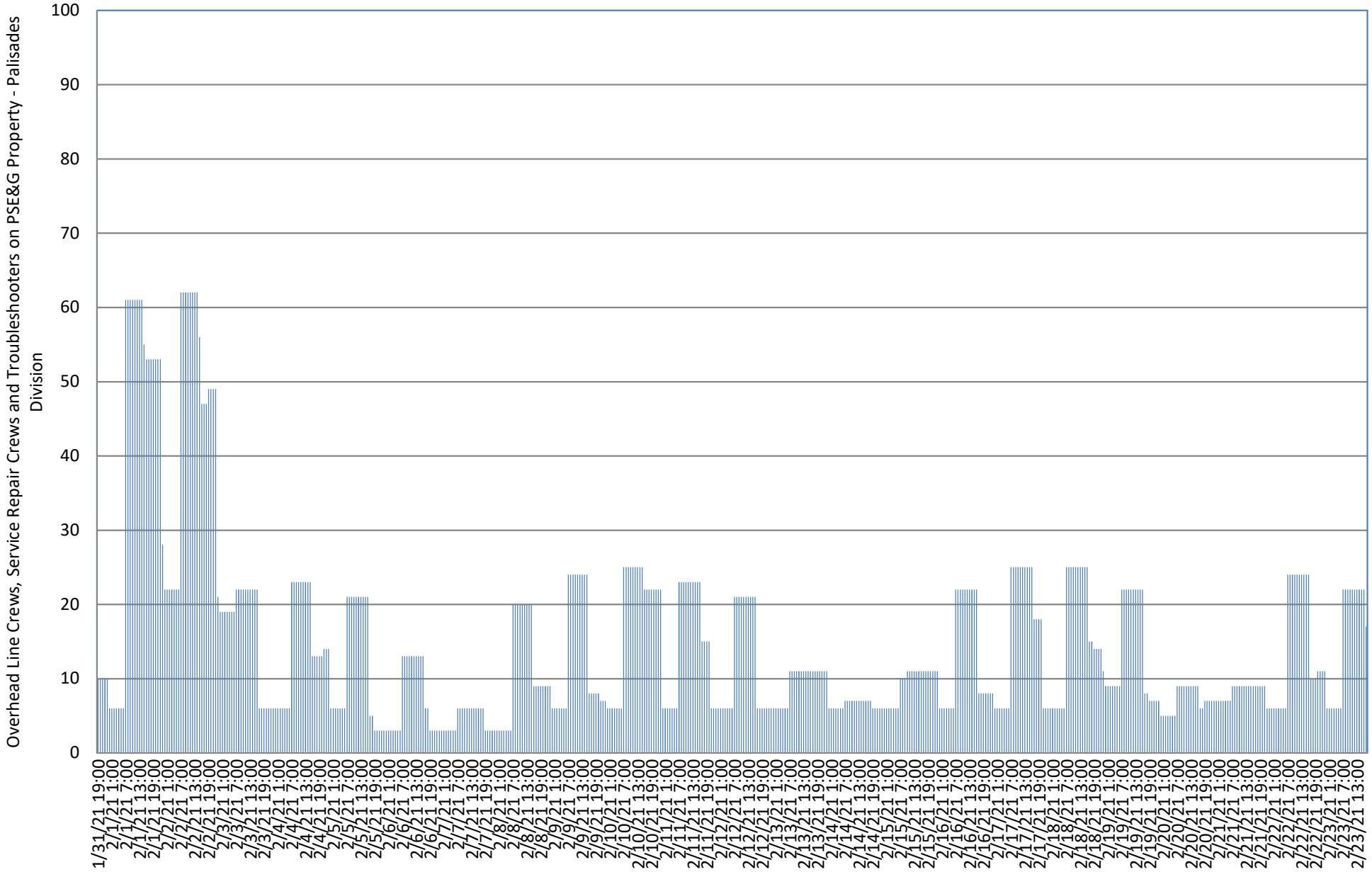
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



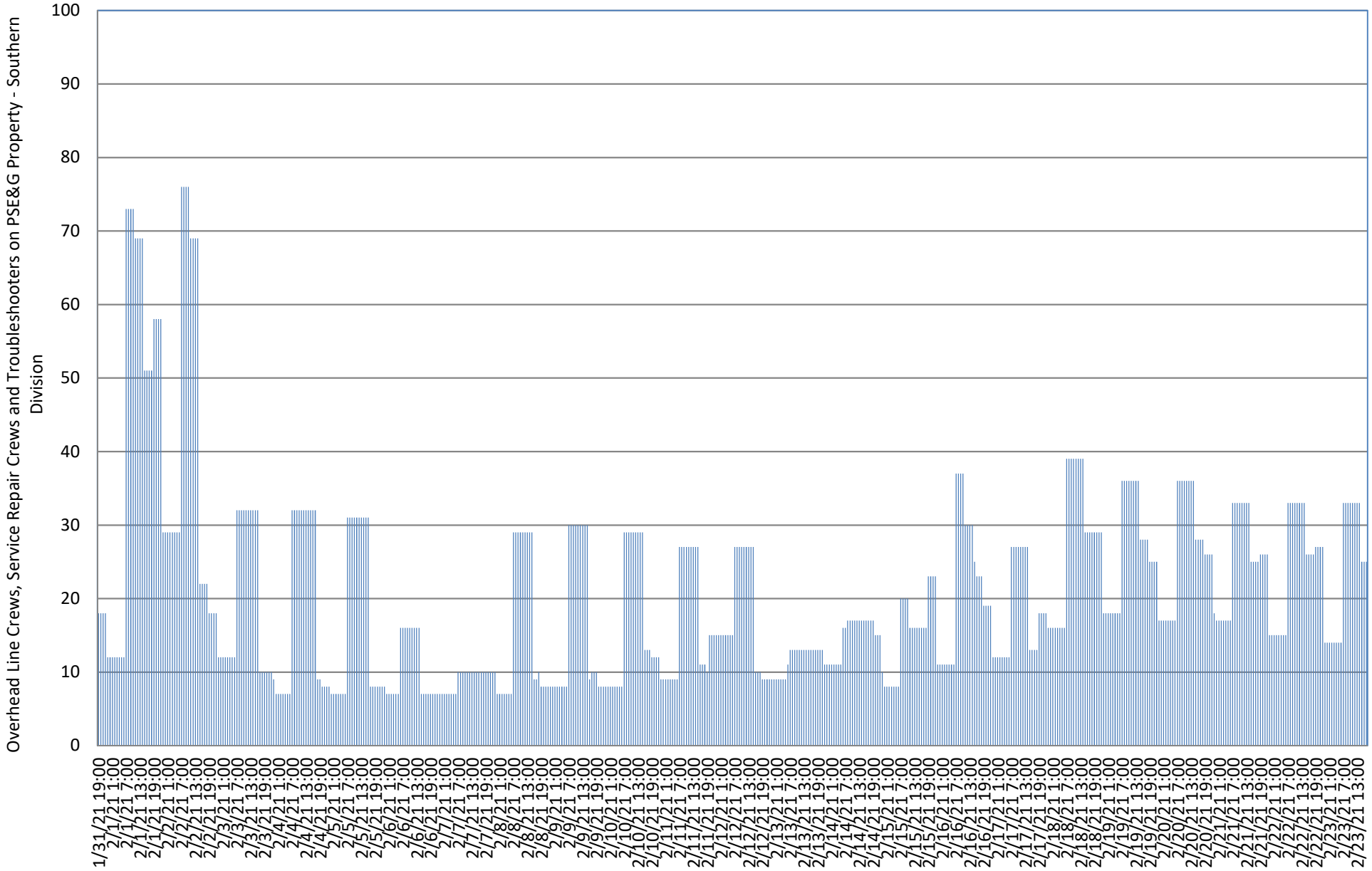
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



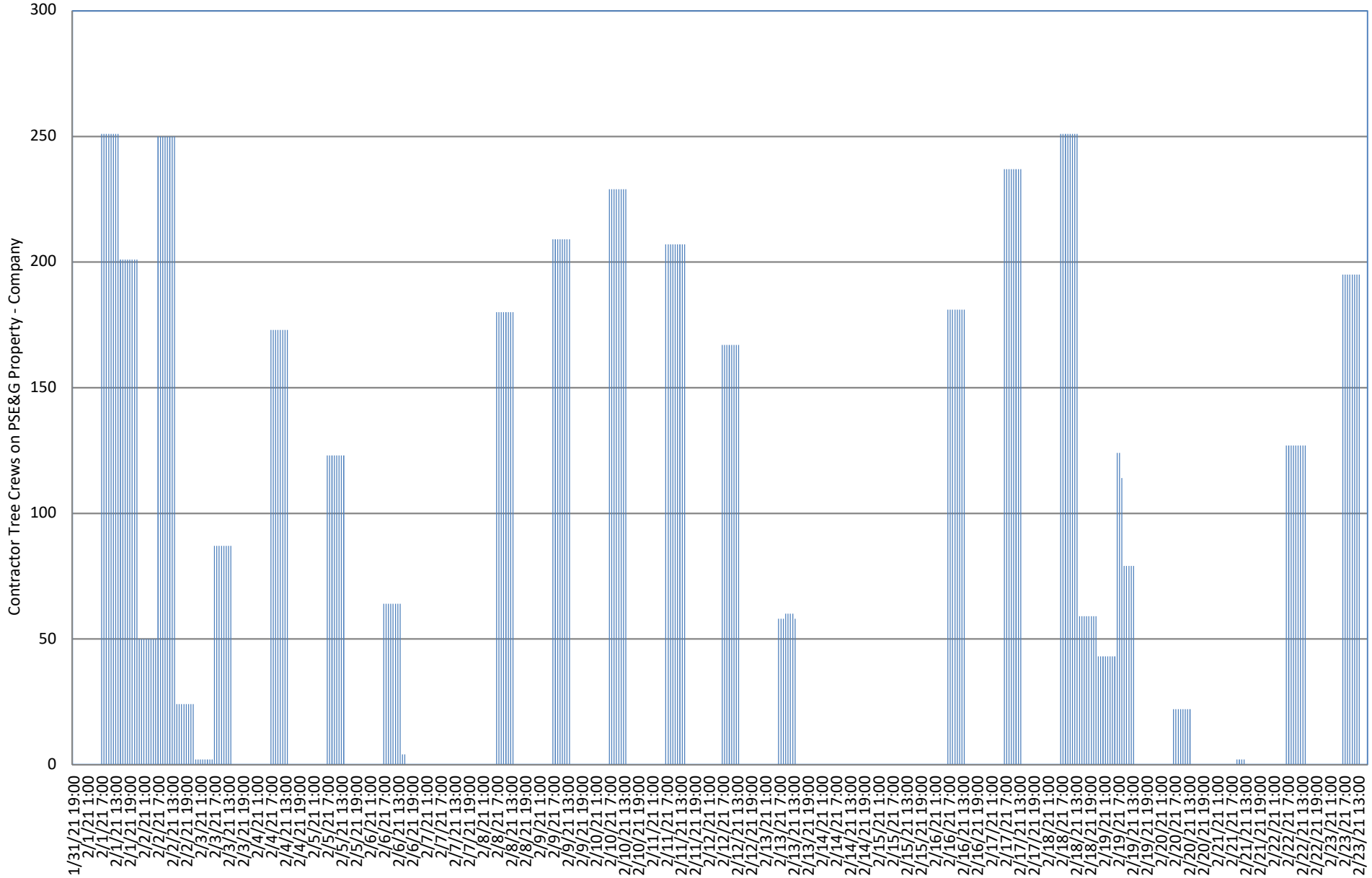
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



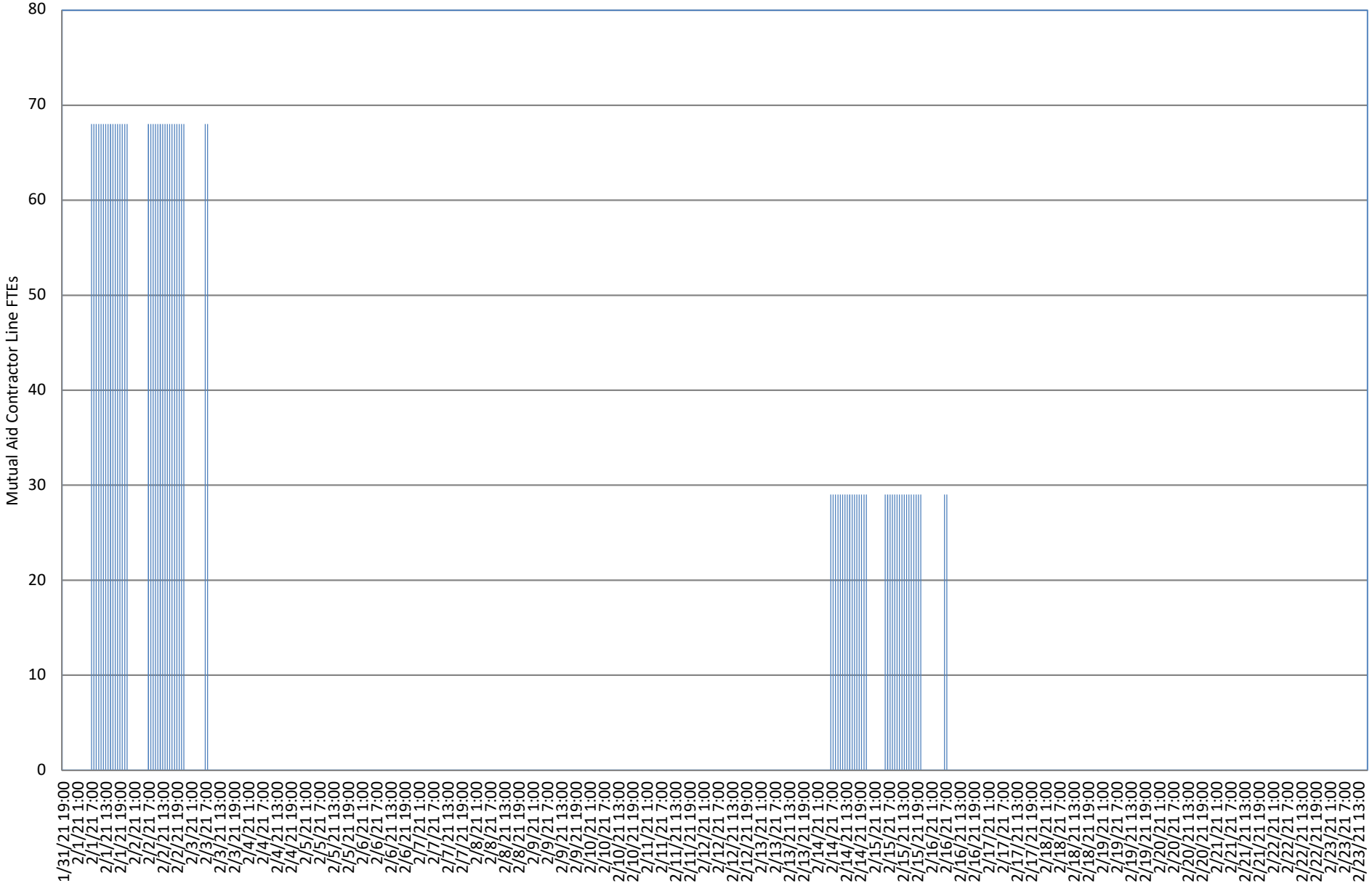
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



Attachment "L"
PSE&G
Mutual Aid Contractor Line FTEs
State of Emergency - Winter Storms - January 31 - Febraury 23, 2021



		Feb Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	-	-	-	-
2	Contractor/Mutual Aid	-	1,084,647	**1,084,647**	1,084,647
3	Tree Removal	-	876,950	**876,950**	876,950
4	Buses	-	-	-	-
5	Other Contractor	-	18,037	18,037	18,037
	Total Contractor		**1,979,634**	**1,979,634**	**1,979,634**
				-	
6	Material	-	-	-	-
				-	
7	Food	-	-	-	-
8	Lodging	-	-	-	-
9	Security	-	-	-	-
10	Water and Ice	-	-	-	-
14	Email Alerts	-	-	-	-
11	Other	-	-	-	-
	Total Other		-	-	-
				-	
	Total Incurred		**1,979,634**	**1,979,634**	**1,979,634**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	-	**1,979,634**	**1,979,634**	**1,979,634**

September 4, 2020

Via Electronic Mail and Overnight Mail

James Giuliano, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
TROPICAL STORM ISAIAS, MUTUAL AID TO PSEG-LI
AND STATE OF EMERGENCY
AUGUST 4-13, 2020

Dear Director Giuliano:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for Tropical Storm Isaias that affected PSE&G's entire service territory, during the State of Emergency from August 4-13, 2020.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Respectfully submitted,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordalisio, President
Upendra Chivukula, Commissioner
Robert Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Stacy Peterson, Director

PSE&G'S INITIAL REPORT TO THE BPU
MAJOR EVENT
TROPICAL STORM ISAIAS, MUTUAL AID TO PSEG-LI AND STATE OF EMERGENCY
AUGUST 4 - 13, 2020

EXECUTIVE SUMMARY

Tropical Storm Isaias affected PSE&G's entire service territory with the initial effects of the storm's impact being felt shortly after midnight on August 4, 2020. Wind gusts of 55 - 65 MPH and rainfall amounts of 2" - 6" were predicted. Governor Phil Murphy declared a State of Emergency at 0500 hrs. that morning. This weather event will rank as one of the worst storms in PSE&G's history in terms of the number of customers interrupted, with a preliminary estimate indicating that 575,000 customers experienced an extended interruption. Due to the severity of the weather event and the plant damage that was experienced, exact data involving the number of customers interrupted and the number of plant damage locations is not available at this time. PSE&G will provide Board staff with a final Major Event Report after a thorough review of all storm related data has been completed.

PSE&G began storm response planning for Tropical Storm Isaias on July 30 with reviews of PSE&G's 72/48/24 hour checklists beginning on July 31. A 1300 hrs. conference call was held on July 31, to discuss storm preparations and Mutual Aid needs. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on the call as well as subsequent calls of this nature beginning on August 2.

PSE&G began securing Mutual Aid Line FTEs on July 31, when 220 contractor Line FTEs were obtained. 70 of these FTEs came from Nova Scotia. PSE&G appreciates the assistance that Board staffer James Bruncati provided in helping with the border crossing. PSE&G requested a 1500 hrs. NAMAG conference call. On that call, PSE&G requested 300 Line FTEs but did not receive any commitments. PSE&G continued to secure contractor Line FTEs and on August 1 had secured commitments for 420 Line FTEs. During a 1500 hrs. NAMAG conference call on August 2, PSE&G requested 1,300 Line FTEs but did not receive any commitments.

After the 1500 hrs. NAMAG call on August 2, NAMAG leadership contacted the Southeast Electric Exchange (SEE) Mutual Assistant Group for resources. During a 2100 hrs. NAMAG call that evening, SEE provided a list of contractor companies that FP&L was going to release. On August 3 at 0700 hrs., PSE&G was able to secure 700 Line FTEs from FP&L. Also at that time, PSE&G was able to secure an additional 275 Line FTEs outside of NAMAG. It was extremely important and beneficial to PSE&G's storm restoration efforts to have secured these Mutual Aid Line FTEs prior to the arrival of Tropical Storm Isaias.

Another NAMAG call was held on August 4 at 0800 hrs. during which PSE&G requested 300 Line FTEs and was able to secure 75 from FP&L. At the end of the day on August 4, PSE&G had secured 1,050 Line FTEs, via NAMAG and 384 Line FTEs via other means for a total of 1,434 Line FTEs.

During a NAMAG call on August 5 at 0800 hrs. PSE&G requested 1,000 Line FTEs and secured 287 Line FTEs.

Another NAMAG call was held on August 6, at 0800 hrs. At that time, PSE&G had secured 1,929 Line FTEs. During the call, PSE&G requested 500 Line FTEs and was able to secure 80 Line FTEs. At the end of the day, PSE&G had secured 1,998 Line FTEs.

During a NAMAG call on August 7 at 0900 hrs., PSE&G requested 250 Line FTEs but did not receive any commitments. At the end of the day, PSE&G had secured 2,004 Line FTEs.

Another NAMAG call was held on August 8 at 1400 hrs. PSE&G did not request any assistance during the call. The final number of Line FTEs secured by PSE&G was 2,019.

PSE&G received Mutual Aid crews from the following states:

Indiana	Maryland	Iowa	Oklahoma	Illinois	Pennsylvania
Missouri	Florida	New Jersey	Alabama	Louisiana	Kentucky
Wisconsin					

And the Province of Nova Scotia.

PSE&G was also successful in obtaining additional tree-trimming FTEs. Efforts to obtain them began on July 31. By August 2, 132 were secured, by August 3, 226, by August 4, 383, by August 6, for a total of 722. At the same time, PSE&G utilized 270 contractor tree trimmers already on the property, for a total of 992.

The tree-trimming crews came from the following states:

West Virginia	Tennessee	Indiana	Missouri	Arkansas	Ohio
Florida	Pennsylvania	Michigan	Mississippi	Virginia	Alabama
North Carolina	Wisconsin	South Carolina			

On August 7, PSE&G was able to move approximately 190 Mutual Aid Line FTEs from Central Division to Palisades Division. On August 8 and 9, PSE&G was able to move all the Mutual Aid Line FTEs from Central Division to Metropolitan and Palisades Divisions.

On August 8, PSE&G was able to move approximately 400 Mutual Aid Line FTEs from Southern Division to Palisades Division. On August 9, PSE&G was able to move all the Mutual Aid Line FTEs from Southern Division to Palisades Division. Southern Division was also able to move line and service restoration crews to Central and Metropolitan Divisions on August 8 and 9 respectively.

On the morning of August 9, PSE&G began to release Tree Trimming FTEs and on the morning of August 10, PSE&G began to release Mutual Aid Line FTEs. On the morning of August 12, the remaining Mutual Aid Line FTEs and Tree Trimming FTEs were released.

That morning, PSE&G sent 62 Line FTEs to PSEG-LI for a one day, 16 hour, Mutual Aid Storm Restoration assignment as follows:

Central Division	- 9
Metropolitan Division	- 7
Palisades Division	- 19
Southern Division	- 11
P&C	- 16
Total	- 62

PSE&G, along with the other EDCs, participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G opened its Emergency Operations Center (EOC) on August 4 at 0700 hrs. It remained open in a virtual mode, until August 13 at 0700 hrs.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the Regional Public Affairs (RPA) Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G monitored possible flooding of substations prior to the event using the Stevens Institute of Technology's Flood Model. The Model indicated possible flooding of Marshall Street Substation in Hoboken. Protective barriers were in place around the station's 4-kV equipment and pumps were in place inside of the substation. Fortunately, flooding did not occur.

PSE&G opened six water and ice comfort stations at locations throughout the service territory on August 5.

OPERATING REPORT

The preliminary number of customer interruptions and the final restoration times for customers as of 1100 hrs. on September 2 are as follows:

Division	Preliminary Number of Customers Interrupted	Restoration Entire Circuits	Restoration Areas / Services	Restoration End of SOE
Central	169,173	August 8 - 0810 hrs.	August 11 – 1230 hrs.	August 13* - 1401 hrs.
Metropolitan	170,677	August 7 - 1112 hrs.	August 11 - 1209 hrs.	August 13* 1729 hrs.
Palisades	211,280	August 7 - 0639 hrs.	August 10 - 1347 hrs.	August 13* - 1523 hrs.
Southern	251,717	August 7 - 0400 hrs.	August 10 - 1229 hrs.	August 13* - 1920 hrs.
Total	802,847			

*Outages occurred on August 13.

A preliminary estimate indicated that 575,000 customers experienced and extended interruption. The number and percentage of customers restored were based on that amount. The number and percentage of customers restored for data as of 1100 hrs. on September 2 is also listed below.

Date / Time	Preliminary Number of Customers Restored	Preliminary Percentage of Customers Restored	Updated Number of Customers Restored	Updated Percentage of Customers Restored
August 5 - 0900 hrs.	276,000	48%	347,995	43%
August 6 - 0900 hrs.	430,000	75%	547,603	68%
August 7 - 0900 hrs.	517,000	90%	655,392	82%
August 8 - 0900 hrs.	552,000	96%	722,625	90%
August 9 - 0900 hrs.	569,000	99%	750,650	94%
August 10 - 0900 hrs.			757,397	94%
August 11 - 0900 hrs.			766,512	96%

Attached are the following preliminary Customer Restoration Summary Graphs for this weather event:

Attachment "A" - Company Wide
Attachment "B" - Central Division
Attachment "C" - Metropolitan Division
Attachment "D" - Palisades Division
Attachment "E" - Southern Division

Tropical Storm Isaias affected PSE&G's entire service territory with the initial effects of the storm's impact being felt shortly after midnight on August 4, 2020. Wind gusts of 55 - 65 MPH and rainfall amounts of 2" - 6" were predicted. Governor Phil Murphy declared a State of Emergency at 0500 hrs. that morning. This weather event will rank as one of the worst storms in PSE&G's history in terms of the number of customers interrupted, with a preliminary estimate indicating that 575,000 customers experienced an extended interruption. Due to the severity of the weather event and the plant damage that was experienced, exact data involving the number of customers interrupted and the number of plant damage locations is not available at this time. PSE&G will provide Board staff with a final Major Event Report after a thorough review of all storm related data has been completed.

PSE&G began storm response planning for Tropical Storm Isaias on July 30, with reviews of PSE&G's 72/48/24 hour checklists beginning on July 31. A 1300 hrs. conference call was held on July 31 to discuss storm preparations and Mutual Aid needs. Representatives from Electric Delivery's General Office staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center (ESOC), along with personnel from other operating and staff departments of the Company were involved on the call as well as subsequent calls of this nature beginning on August 2.

PSE&G began securing Mutual Aid Line FTEs on July 31, when 220 contractor Line FTEs were obtained. 70 of these FTEs came from Nova Scotia. PSE&G appreciates the assistance that Board staffer James Bruncati provided in helping with the border crossing. PSE&G requested a 1500 hrs. NAMAG conference call. On that call, PSE&G requested 300 Line FTEs but did not receive any commitments. PSE&G continued to secure contractor Line FTEs and on August 1 had secured commitments for 420 Line FTEs. During a 1500 hrs. NAMAG conference call on August 2, PSE&G requested 1,300 Line FTEs but did not receive any commitments.

After the 1500 hrs. NAMAG call on August 2, NAMAG leadership contacted the Southeast Electric Exchange (SEE) Mutual Assistant Group for resources. During a 2100 hrs. NAMAG call that evening, SEE provided a list of contractor companies that FP&L was going to release. On August 3, at 0700 hrs., PSE&G was able to secure 700 Line FTEs from FP&L. Also at that time, PSE&G was able to secure an additional 275 Line FTEs

outside of NAMAG. It was important extremely important and beneficial to PSE&G's storm restoration efforts to have secured these Mutual Aid Line FTEs prior to the arrival of Tropical Storm Isaias.

Another NAMAG call was held on August 4 at 0800 hrs. during which PSE&G requested 300 Line FTEs and was able to secure 75 from FP&L. At the end of the day on August 4, PSE&G had secured 1,050 Line FTEs, via NAMAG and 384 Line FTEs via other means for a total of 1,434 Line FTEs.

During a NAMAG call on August 5 at 0800 hrs., PSE&G requested 1,000 Line FTEs and secured 287 Line FTEs.

Another NAMAG call was held on August 6, at 0800 hrs. At that time, PSE&G had secured 1,929 Line FTEs. During the call, PSE&G requested 500 Line FTEs and was able to secure 80 Line FTEs. At the end of the day, PSE&G had secured 1,998 Line FTEs.

During a NAMAG call on August 7 at 0900 hrs. PSE&G requested 250 Line FTEs but did not receive any commitments. At the end of the day, PSE&G had secured 2,004 Line FTEs.

Another NAMAG call was held on August 8 at 1400 hrs. PSE&G did not request any assistance during the call. The final number of Line FTEs secured by PSE&G was 2,019.

PSE&G received Mutual Aid crews from the following states:

Indiana	Maryland	Iowa	Oklahoma	Illinois	Pennsylvania
Missouri	Florida	New Jersey	Alabama	Louisiana	Kentucky
Wisconsin					

and the Province of Nova Scotia.

PSE&G was also successful in obtaining additional tree trimming FTEs. Efforts to obtain them began on July 31. By August 2, 132 were secured, by August 3, 226 by August 4, 383, by August 6, the final total of 722 at the same time, PSE&G utilized 270 contractor tree trimmers already on the property, for a total of 992.

The tree-trimming crews came from the following states:

West Virginia	Tennessee	Indiana	Missouri	Arkansas	Ohio
Florida	Pennsylvania	Michigan	Mississippi	Virginia	Alabama
North Carolina	Wisconsin	South Carolina			

On August 7, PSE&G was able to move approximately 200 Mutual Aid Line FTEs from Central Division to Palisades Division. On August 8 and 9, PSE&G was able to move all the Mutual Aid Line FTEs from Central Division to Metropolitan and Palisades Divisions.

On August 8, PSE&G was able to move approximately 400 Mutual Aid Line FTEs from Southern Division to Palisades Division. On August 9, PSE&G was able to move all the Mutual Aid Line FTEs from Southern Division to Palisades Division. Southern Division was also able to move line and service restoration crews to Central and Metropolitan Divisions on August 8 and 9 respectively.

On the morning of August 9, PSE&G began to release tree-trimming FTEs and on the morning of August 10, PSE&G began to release Mutual Aid Line FTEs. On the morning of August 12, the remaining Mutual Aid Line FTEs and tree-trimming FTEs were released.

That morning, PSE&G sent 62 Line FTEs to PSEG-LI for a one day, 16 hour, Mutual Aid Storm Restoration assignment as follows:

Central Division	- 9
Metropolitan Division	- 7
Palisades Division	- 19
Southern Division	- 11
P&C	- 16
Total	- 62

PSE&G, along with the other EDCs, participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G opened its Emergency Operations Center (EOC) on August 4 at 0700 hrs. It remained open in a virtual mode, until August 13 at 0700 hrs.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G monitored possible flooding of substations prior to the event using the Stevens Institute of Technology's Flood Model. The Model indicated possible flooding of Marshall Street Substation in Hoboken. Protective barriers were in place around the station's 4-kV equipment and pumps were in place inside of the substation. Fortunately, flooding did not occur.

The peak wind gust measured in PSE&G's service territory on August 4 was 68 MPH. There were six hours of sustained winds of 30 MPH with gusts of over 50 MPH.

PSE&G opened six water and ice comfort stations at locations throughout the service territory on August 5.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for this weather event:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Mutual Aid Contractor Tree Trimming FTEs
Attachment "M" - Mutual Aid Contractor Line FTEs Assisting Central Division
Attachment "N" - Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
Attachment "O" - Mutual Aid Contractor Line FTEs Assisting Palisades Division

Attachment "P" - Mutual Aid Contractor Line FTEs Assisting Southern Division
Attachment "Q" - Southern Division Overhead Line and Service Repair Crews Assisting Central Division.
Attachment "R" - Southern Division Overhead Line and Service Repair Crews Assisting Metropolitan Division
Attachment "S" - Mutual Aid to PSEG - LI

The following is a listing of the Mutual Aid Contractors' Line FTEs that PSE&G secured:

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
50	50	Inside contractors Henkel's & McPhee (NJ/PA)	Southern	HOLD ON PSE&G-NJ Thru 8/11
75	75	Henkel's & McCoy (Wisconsin/Illinois/Michigan)	Southern	HOLD ON PSE&G-NJ Thru 8/10
35	35	Henkel's & McCoy - (Maryland)	Southern	HOLD ON PSE&G-NJ Thru 8/11
50	50	AEP Swepco Internal Crews (Louisiana)	Southern	Released 8/10/2020 7am
52	52	AEP Swepco Contractors - Non-Union Crews (Louisiana),	Southern	Released 8/10/2020 7am
82	82	Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
22	22	2nd Wave Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
21	21	3rd Wave Centerphase Energy -Non Union Contractors (Oklahoma)	Southern	Released 8/10/2020 7am
53	53	Mid-Con Energy - NonUnion Contactors (Oklahoma)	Southern	Released 8/10/2020 7am
42	42	Pike Electric (Oklahoma)	Southern	Released 8/10/2020 7am
Total	**482**			
50	50	Riggs-Distler (NJ/PA)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/10
120	120	Onpower - (Florida)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/11
58	34	2nd Wave - Onpower - (Florida)	Central - Hadley Rd	HOLD ON PSE&G-NJ Thru 8/11
192	192	OneSource - Non Union Contractors (Florida)	Central - Hadley Rd	Released 8/10/2020 7am
95	95	2nd Wave OneSource - Non Union Contractors (Florida)	Central - Hadley Rd	Released 8/10/2020 7am
28	28	Alliant - Michels Power - (IOWA)	Central - Hadley Rd	Released 8/10/2020 7am
34	58	United Electric - (Kentucky)	Central - Hadley Rd	Released 8/10/2020 7am
Total	**577**			

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
70	70	East Coast Power - (Nova Scotia)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
50	50	3rd Wave MP Systems/Onpower - (Florida)	Northern - Wayne Staging	Released 8/11/2020 7am
45	45	CC Power - (Michigan)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
104	104	Lee Electric (North Carolina)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
77	77	Ameren Contractors - (Missouri)	Northern - Wayne Staging	Released to PSEG-LI VIA NAMAG 8/10/2020
56	56	Mid-Con Energy - Non Contractors (Oklahoma)	Northern - Wayne Staging	Released to PSEG-LI 8/10/2020
8	8	Valiant - (PA)	Northern - Wayne Staging	Released 8/10/2020 7am
Sub Total	**410**			
80	80	Henkel's & McCoy (PA)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10
214	214	Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
21	21	2nd Wave Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
15	15	3rd Wave Collective Storm Services - (Alabama)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
32	32	Mohawk Electric - (Missouri)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
20	20	Mohawk Electric - (Missouri)	Northern - Bergen Comm. College	Released to PSEG-LI VIA NAMAG 8/10/2020
117	117	Heart Utilities - (Florida)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10

FTEs Requested	FTEs Secured	Comments	Staging	Released Day/time
20	20	Henkel's & McCoy (NJ)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/11
31	31	Heart Utilities - (Florida)	Northern - Bergen Comm. College	HOLD ON PSE&G-NJ Thru 8/10
Sub Total	**550**			
Total	**2,019**			

The following is a listing of the tree-trimming contractors' FTEs that PSE&|G secured:

Contractor	**Crew Count**	**FTE**	**Actual Date of Arrival**	**Actual Time of Arrival**	**Release Date**	**Release Time**	**Origin Utility**	**City & State of Origin**
Nelson	4	16	8/3/2020	7:20 PM	8/9/2020	7:00 PM	AEP-WV	Huntington, WV
Nelson	5	15	8/3/2020	7:20 PM	8/9/2020	7:00 PM	AEP-WV	Beckley, WV
Nelson	0	1	8/5/2020	11:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Nelson	5	11	8/6/2020	5:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Nelson	5	11	8/6/2020	5:00 PM	8/9/2020	7:00 PM	AEP OH	Canton, OH
Asplundh	7	18	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	10	21	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	10	23	8/3/2020	11:30 PM	8/10/2020	9:00 AM	Detroit Edison Wave 1	Howell, MI
Asplundh	5	13	8/6/2020	11:00 PM	8/12/2020	7:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	7	18	8/6/2020	11:00 PM	8/12/2020	7:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	6	13	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Detroit Edison Wave 2	Howell, MI
Asplundh	5	11	8/7/2020	8:00 AM	8/10/2020	9:00 AM	Consumers Energy	Jackson, MI
Asplundh	5	12	8/7/2020	8:00 AM	8/10/2020	9:00 AM	Consumers Energy	Mt Pleasant, MI
Asplundh	5	11	8/6/2020	10:00 PM	8/12/2020	7:00 AM	We-Energies, Richland Energies, Oakdale Electric & Rock Energies	Waukesha, WI, Richland Center, WI, Oakdale, WI & Beloit, WI
Asplundh	6	19	8/6/2020	10:00 PM	8/10/2020	9:00 AM	Petit Jean Elect Coop, Memphis Gas Water Light, Jonesboro CWL	Clinton, AR, Memphis, TN, Jonesboro, AR

Contractor	Crew Count	FTE	Actual Date of Arrival	Actual Time of Arrival	Release Date	Release Time	Origin Utility	City & State of Origin
Asplundh	3	8	8/7/2020	9:00 AM	8/10/2020	9:00 AM	4 County	West Point, MS
Asplundh	4	9	8/7/2020	9:00 AM	8/10/2020	9:00 AM	Central Electric	Kosciusko, MS
Asplundh	3	10	8/7/2020	9:00 AM	8/10/2020	9:00 AM	Central Electric	Kosciusko, MS
Asplundh	7	16	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Dothan Utility	Dothan, AL
Asplundh	3	11	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Pioneer	Greenville, AL
Asplundh	5	11	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Joe Wheeler	Moultan, AL
Asplundh	3	9	8/6/2020	11:00 PM	8/10/2020	9:00 AM	Bessemer	Bessemer, AL
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Canton, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Chillicothe, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Canton, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Wooster, OH
Asplundh	0	1	8/4/2020	7:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Millersport, OH
Asplundh	0	1	8/4/2020	7:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Millersport, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Crooksville, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Pomeroy, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	McConnelsville, OH
Asplundh	5	11	8/4/2020	10:30PM	8/10/2020	9:00 AM	AEP OH Wave 1	Athens, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Chillicothe, OH
Asplundh	5	11	8/4/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 1	Crooksville, OH
Asplundh	6	13	8/6/2020	3:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Columbus, OH
Asplundh	6	13	8/6/2020	6:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Portsmouth, OH
Asplundh	5	12	8/6/2020	3:00 PM	8/10/2020	9:00 AM	AEP OH Wave 2	Coshocton, OH
ARS	12	38	8/3/2020	11:45 PM	8/9/2020	4:00 PM	Clay Electric	Jacksonville, FL
NG Gilbert / Townsend	8	18	8/4/2020	2:00 AM	8/11/2020	3:00 PM	Clark Rem / Meade Rec	Bradenburg, KY / Sellersburg, IN
NG Gilbert / Townsend	6	14	8/3/2020	11:00 PM	8/9/2020	4:00 PM	SEIREMC	Osgood, IN
NG Gilbert / Townsend	6	20	8/3/2020	7:00 PM	8/10/2020	9:00 AM	APCO	Fayetteville, WV
NG Gilbert / Townsend	5	11	8/3/2020	10:00 PM	8/9/2020	4:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	0	1	8/3/2020	10:00 PM	8/11/2020	3:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	5	11	8/3/2020	9:00 PM	8/9/2020	4:00 PM	APCO	Kingsport, TN
NG Gilbert / Townsend	6	14	8/5/2020	6:30 AM	8/9/2020	4:00 PM	Duke Energy	Martinsville, IN
NG Gilbert / Townsend	4	9	8/5/2020	3:00 AM	8/10/2020	9:00 AM	APCO	Pt Pleasant, WV
NG Gilbert / Townsend	6	19	8/5/2020	12:00 AM	8/10/2020	9:00 AM	APCO	Princeton, WV

Contractor	Crew Count	FTE	Actual Date of Arrival	Actual Time of Arrival	Release Date	Release Time	Origin Utility	City & State of Origin
NG Gilbert / Townsend	5	13	8/5/2020	12:00 AM	8/10/2020	9:00 AM	PEMC & APCO	Burlington, NC & Princeton, WV
NG Gilbert / Townsend	5	11	8/5 & 8/6	3PM & 5:30 AM	8/9/2020	4:00 PM	Duke Energy & SEIREMC	Brookville, IN & Osgood, IN
NG Gilbert / Townsend	5	11	8/7/2020	12:00 PM	8/9/2020	4:00 PM	SEMO Electric	Sikeston, MO
NG Gilbert / Townsend	5	12	8/7/2020	11:00 AM	8/9/2020	4:00 PM	HBPW, SEMO Electric, City of Jackson, City of Sikeston & Black River Electric	Hannibal, MO, Sikeston, MO, Jackson, MO, Fredericktown, MO
NG Gilbert / Townsend	5	12	8/7/2020	11:00 AM	8/9/2020	4:00 PM	Black River Electric	Fredericktown, MO
Valiant	2	7	8/4/2020	12:00 PM	8/11/2020	11:00 AM	N/A	Allentown, PA
Lewis	3	8	8/6/2020	10:00 PM	8/9/2020	4:00 PM	AEP OH	Columbus, OH
Lewis	6	15	8/6/2020	10:00 PM	8/9/2020	4:00 PM	AEP OH	Mansfield, OH
Lewis	4	9	8/6/2020	8:00 PM	8/9/2020	4:00 PM	AEP OH	Cadiz, OH
Lewis	3	6	8/6/2020	8:00 PM	8/9/2020	4:00 PM	AEP OH	Cadiz, OH
Lewis	0	1	8/6/2020	9:30 PM	8/9/2020	4:00 PM	AEP / I&M	Muncie, IN
Lewis	0	1	8/5/2020	6:30 PM	8/9/2020	4:00 PM	Dominion	Chesterfield, VA
Lewis	0	1	8/5/2020	10:30 PM	8/9/2020	4:00 PM	AEP	Winchester, IN
Lewis	0	1	8/7/2020	10:00 PM	8/9/2020	4:00 PM	Duke Energy	Tampa, FL
Lewis	5	11	8/7/2020	12:00 AM	8/9/2020	4:00 PM	Santee Cooper	Conway, SC
Lewis	5	11	8/7/2020	12:00 AM	8/9/2020	4:00 PM	Berkeley Electric	Goose Creek, SC
Total	**291**	**722**						

Arrangements were made to secure four staging areas to support the Mutual Aid crews. These areas became material storage areas for poles, transformers conductors and other material. They were also the locations where these crews received their work assignments and safety briefings.

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning at noon on August 4. It continued until 2100 hrs. on August 10. Liaison support was also provided to the two Inquiry Centers during this weather event. These liaisons assisted on addressing customer inquiries.

Conference calls with mayors and other elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and the Senior Directors and other personnel of the four operating divisions participated on the calls.

There were a maximum of 155 Gas Delivery associates used for standing by downed wires between August 4 and August 11.

PSE&G also secured a contractor to assist in the damage assessment process. The contractor was utilized on August 8 and 9 and consisted of 107 - 2- person teams.

INITIAL TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	-	120
13 & 4-kV	-	1,856
Transformers	-	663
Secondaries	-	577
Services	-	2,203
Poles	-	988
Trees	-	6,000+
Total	-	12,407+

INCIDENTS

The following PSE&G Substations were shut down during this weather event:

Substation	Date	Time off	Time on	Number of Customers
Avenel	August 4	1215	1800 (August 5)	3,833
Clark	August 13	0930	1040 (August 13)	2,360
Harts Lane	August 4	1242	1534	14,179
Hudson Terrace	August 4	1316	1944	1,049
Hudson Terrace	August 10	1404	2220 (August 10)	1,049
Bordentown	August 4	1151	1750	2,667
Medford	August 4	1253	1743	13,413
Montgomery	August 4	1214	1815	3,978
Mount Holly	August 4	1043	2045	4,205
Princeton	August 4	1228	1548	3,363
Southampton	August 4	1034	1439	5,018

The following Hospitals were interrupted during this weather event:

Hospital	Municipality	Date	Time off	Time on
Englewood	Englewood	August 4	1347	1543
Holy Name	Teaneck	August 4	1221	1309
Pascack Valley	Westwood	August 4	1208	1602*
Valley	Ridgewood	August 4	1307	2021
Lourdes Virtua	Willingboro	August 4	1356	1829
Children's Specialized Hospital	Mountainside	August 4	1223	1756

*Delay due to the customer not being able to transfer their switchgear to the back-up circuit.

COMMUNICATIONS

PSE&G participated in eight NAMAG conference calls between July 31 and August 8.

Communications with 12 County Offices of Emergency Management (OEMs) and the City of Newark's Emergency Management Center and began on August 4. The liaison support provided was remote and continued until the OEMs closed.

Conference calls with mayors and other municipal and elected officials concerning storm restoration efforts were held daily beginning on August 3 through August 9. Members of the RPA Department organized the calls and participated on them, as did the Senior Directors and other personnel from each of the four operating divisions.

PSE&G along with the other EDCs participated in three conference calls with Board staff between August 5 and August 13. Communications with Board staff involving this weather event began on July 30 and continued until August 17.

PSE&G's RPA Managers kept in constant contact with municipal and state officials in the areas hardest hit by Isaias. In person meetings, telephone calls, text messages and press releases were used in the communication process. In addition, PSE&G officers were also in contact with those officials.

PSE&G's Corporate Communications Department issued internal communications, press releases and handled multiple newspapers, television and radio information request during the period including interviews with PSE&G executives. Social media was monitored for customer messages and PSE&G utilized social media to communicate with customers.

The initial notification to PSE&G's critical needs (P-4) customers was issued on August 3. Personalized calls were made to affected P-4 customers during this weather event.

SUMMARY

This weather event qualifies as a Major Event Since more than 10% of PSE&G's 2,430,197 customers were interrupted. In addition, PSE&G supplied Mutual Aid to PSEG-LI on August 12 and Governor Phil Murphy declared a State of Emergency, which extended from 0500 hrs. on August 4 to 1500 hrs. on August 13.

It was extremely important and beneficial to PSE&G's storm restoration efforts that PSE&G started to secure Mutual Aid Line FTEs on July 31 and by August 3 had secured commitments for approximately 1,400 Mutual Aid Line FTEs.

The restoration efforts went extremely well. Initial data indicates that 48% of the customers interrupted were restored to service in one day; 75% in two days; 90% in three days; 96% in four days and 99% in five days.

PSE&G's excellent relationship with its unions was beneficial during this event.

There were no issues involving equipment or material during this event.

Board staff, during a conference call with EDCs on August 13, asked that additional information called "Touch Points" be included in their Major Event Reports. These "Touch Points" were summarized in Board staffer Jody Raines' August 14 email. PSE&G's responses to the majority of the information requests are contained in President David Daly's Hearing Statement made before a Joint Meeting of the New Jersey Assembly

Telecommunications and Utilities and Assembly Homeland Security and State Preparedness Committees on August 19. A copy of PSE&G's Hearing Statement is attached. PSE&G's responses to the "Touch Points" are as follows:

Measuring the value of hardening/resiliency efforts and expenditures:

Please refer to President Daly's comments under "Restoration Performance - Benefits of Prior Infrastructure Hardening"

Tree Trimming

An overwhelming majority of the outages can be associated with trees.

Fallen trees prolong service restoration as they block roads and access points to plant damage. The removal of fallen trees in many cases is a time consuming process due to the amount of debris that has to be removed. The larger the fallen tree, the more plant damage that it can cause.

PSE&G looks forward to working with Board staff in addressing the subject of reducing the impact of trees on reliability.

COMMUNICATIONS

Please refer to President Daly's comments under "Communications and OMS"

Preparedness posture/mutual aid actions and effectiveness

Please refer to President Daly's comments under "Storm Preparedness – Mutual Aid and COVID Protocol" Also, the subject of Mutual Aid is addressed in detail in the Major Event Report.

Road Opening Process

The stand by wires down process was utilized for police and fire calls when a cut clear responder was not available.

Troubleshooters at the request of various entities performed road clearing.

Priorities were communicated from County OEMs, the mayors' calls and requests to RPA Managers. There was no backlog.

Issues involving lists received from the NJDOT have been reviewed with Board staff.

AMI

Please refer to President Daly's comments under "Communications and OMS"

PSE&G held a "Lessons Learned" meeting concerning Isaias on August 20. Action Items from the meeting are being developed.

Another conference call with the EDCs and Board staff was held on August 25 to discuss the additional storm related information contained in Jodi Raines' August 21 email. PSE&G's responses follow:

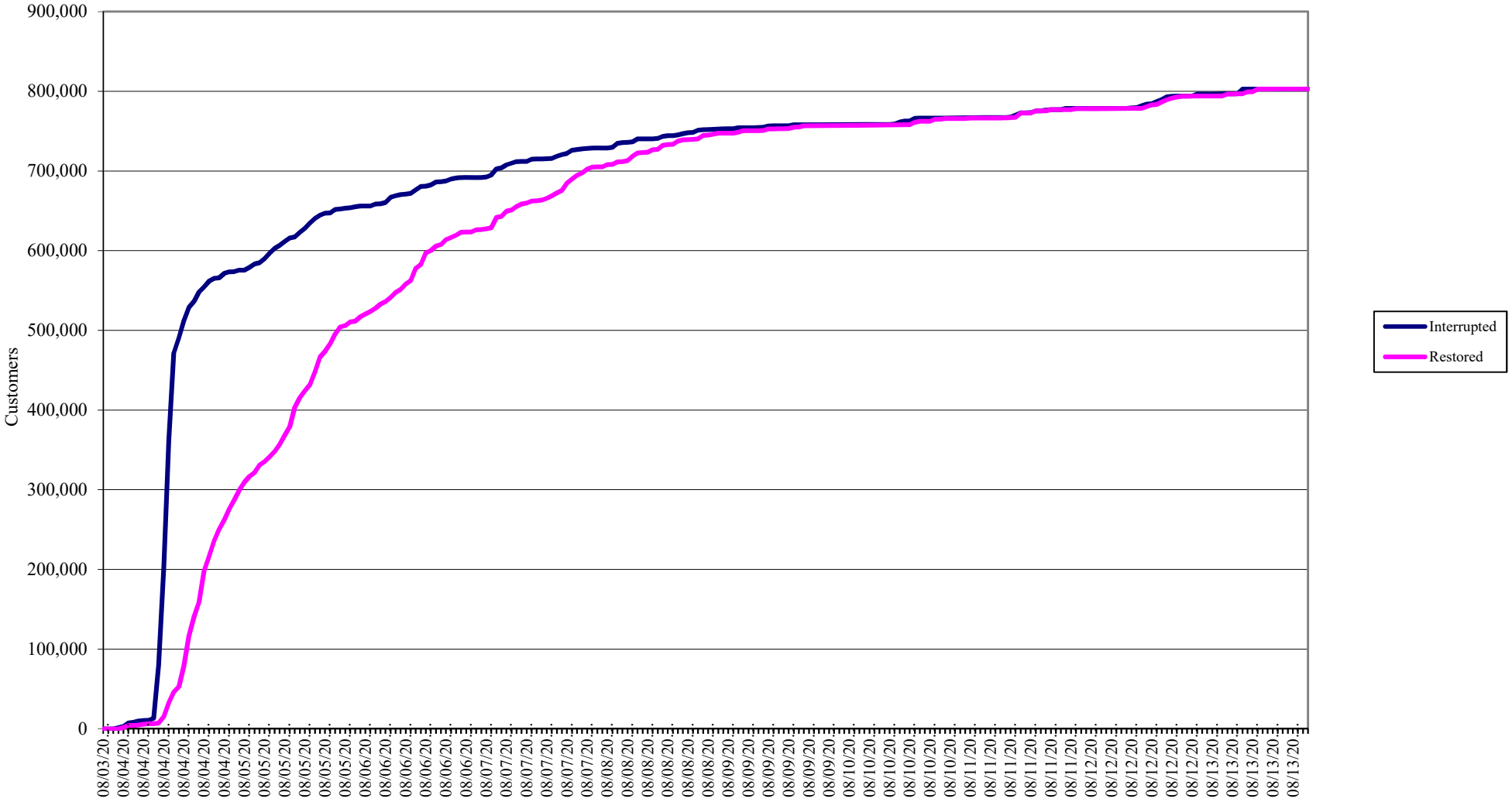
Lists of substations and hospitals interrupted during this event are contained in the Major Event Report, as is a list of Trouble Locations and Classifications.

An overwhelming majority of the primary facility plant damage was caused by total tree failures of seemingly healthy trees, whose removal would have been outside of the trimming scope. Branch failures also caused primary facility plant damage. Falling branches from privately owned non-maintained trees caused the majority of damage to house services.

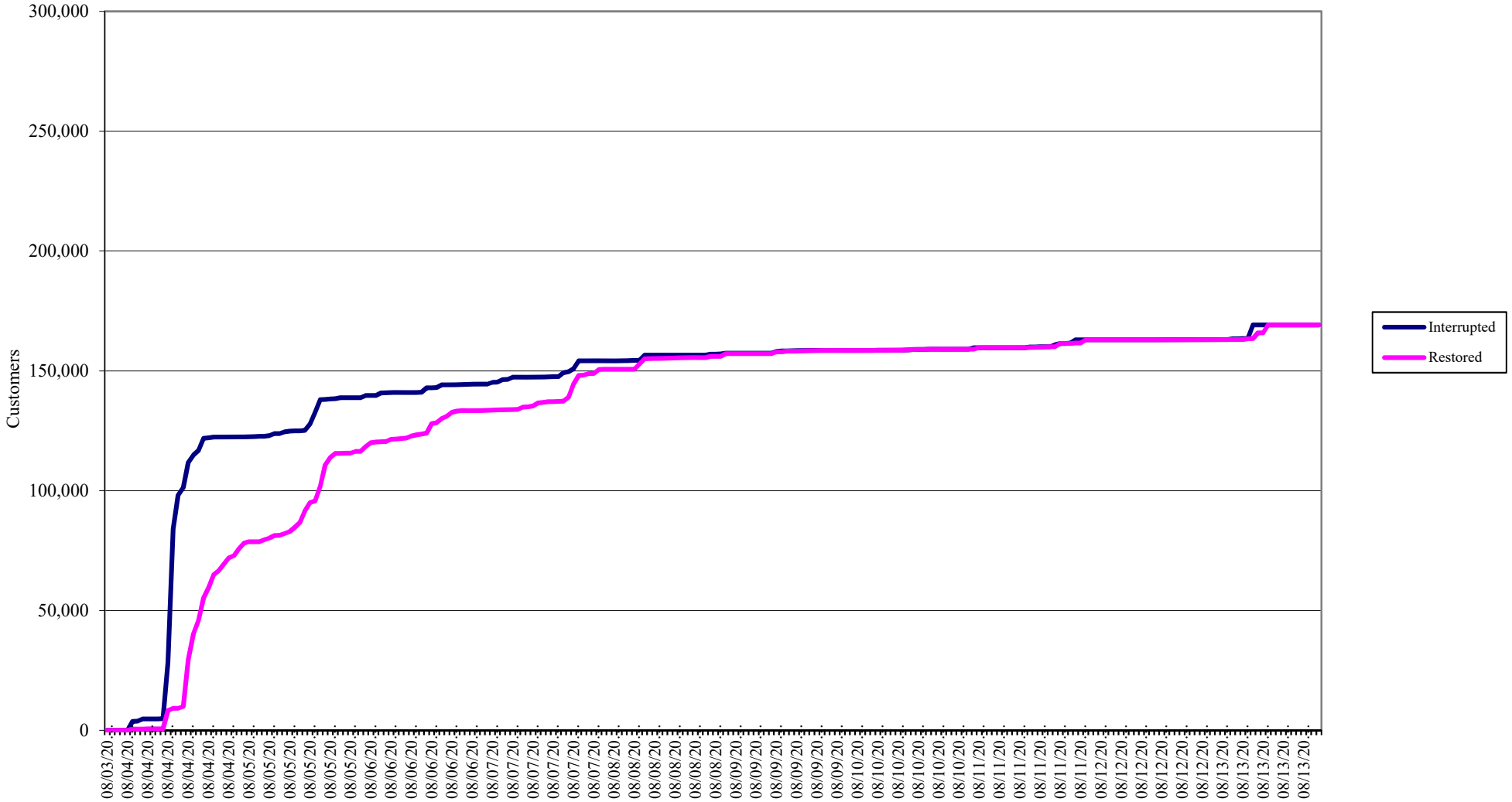
From an initial review of pole damage, fallen trees caused the majority of pole damage. The extreme winds were also the cause of some pole damage.

DWW:bmc
9/2/20

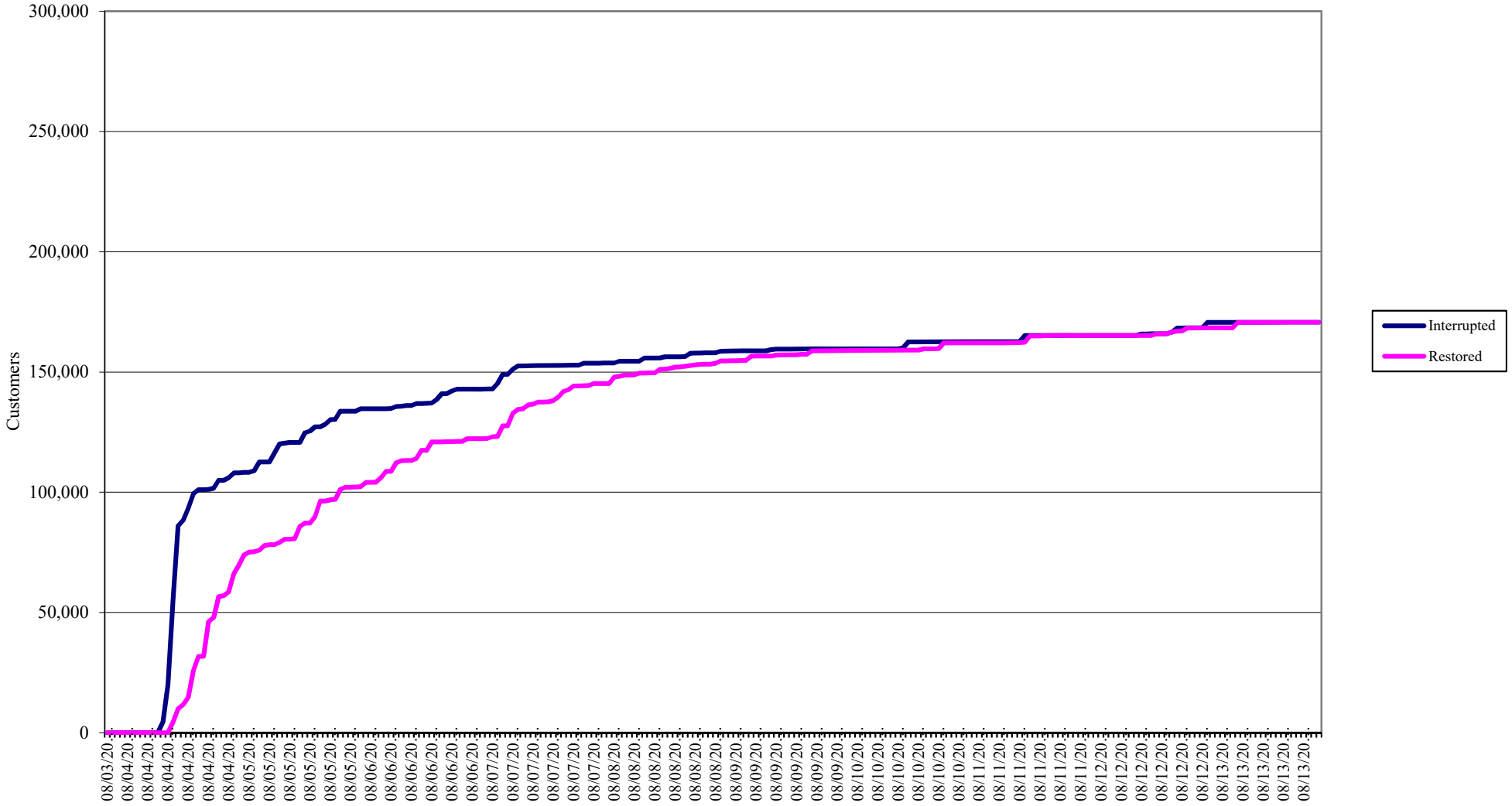
Attachment "A"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Company Wide



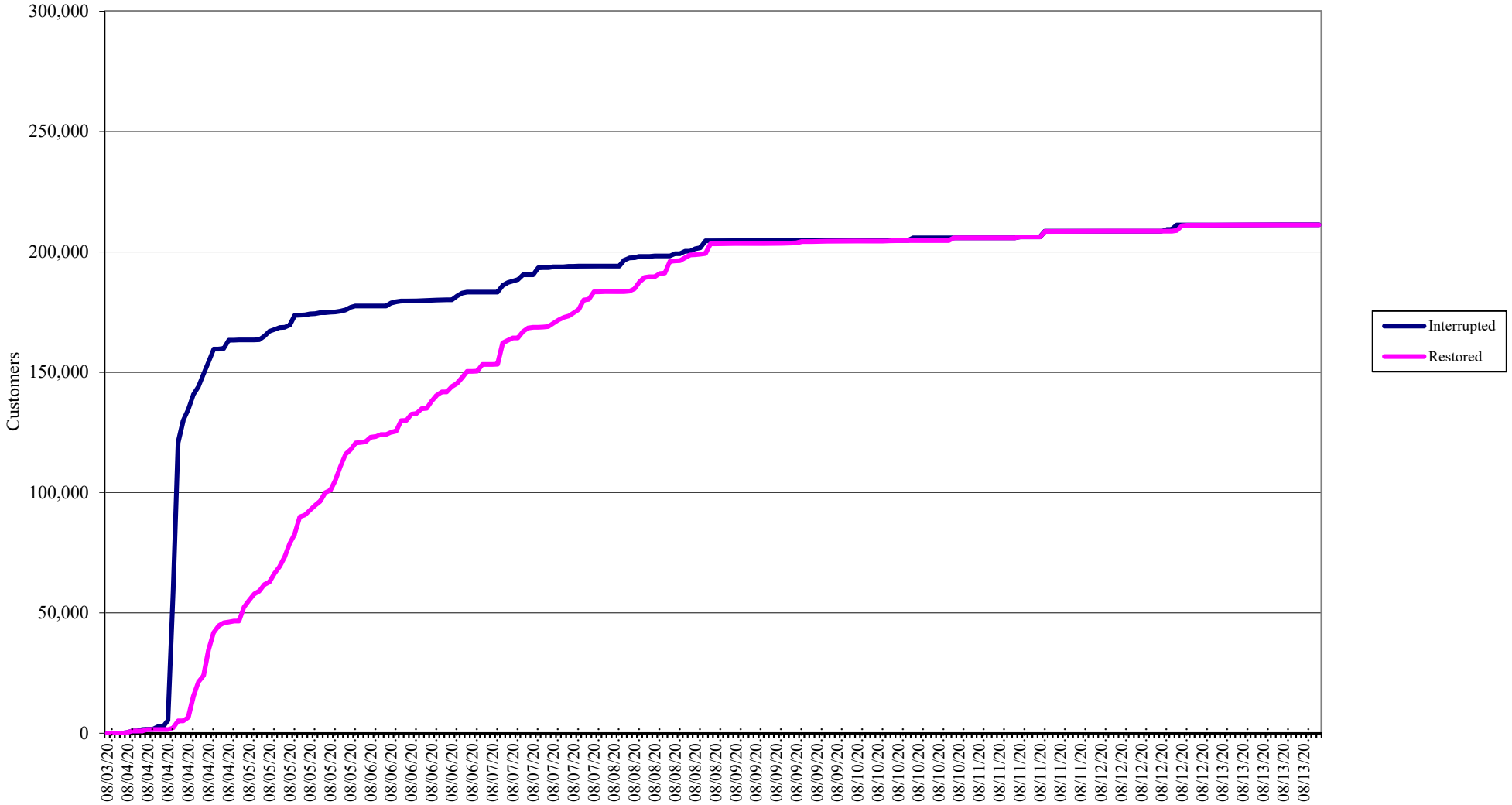
Attachment "B"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Central Division



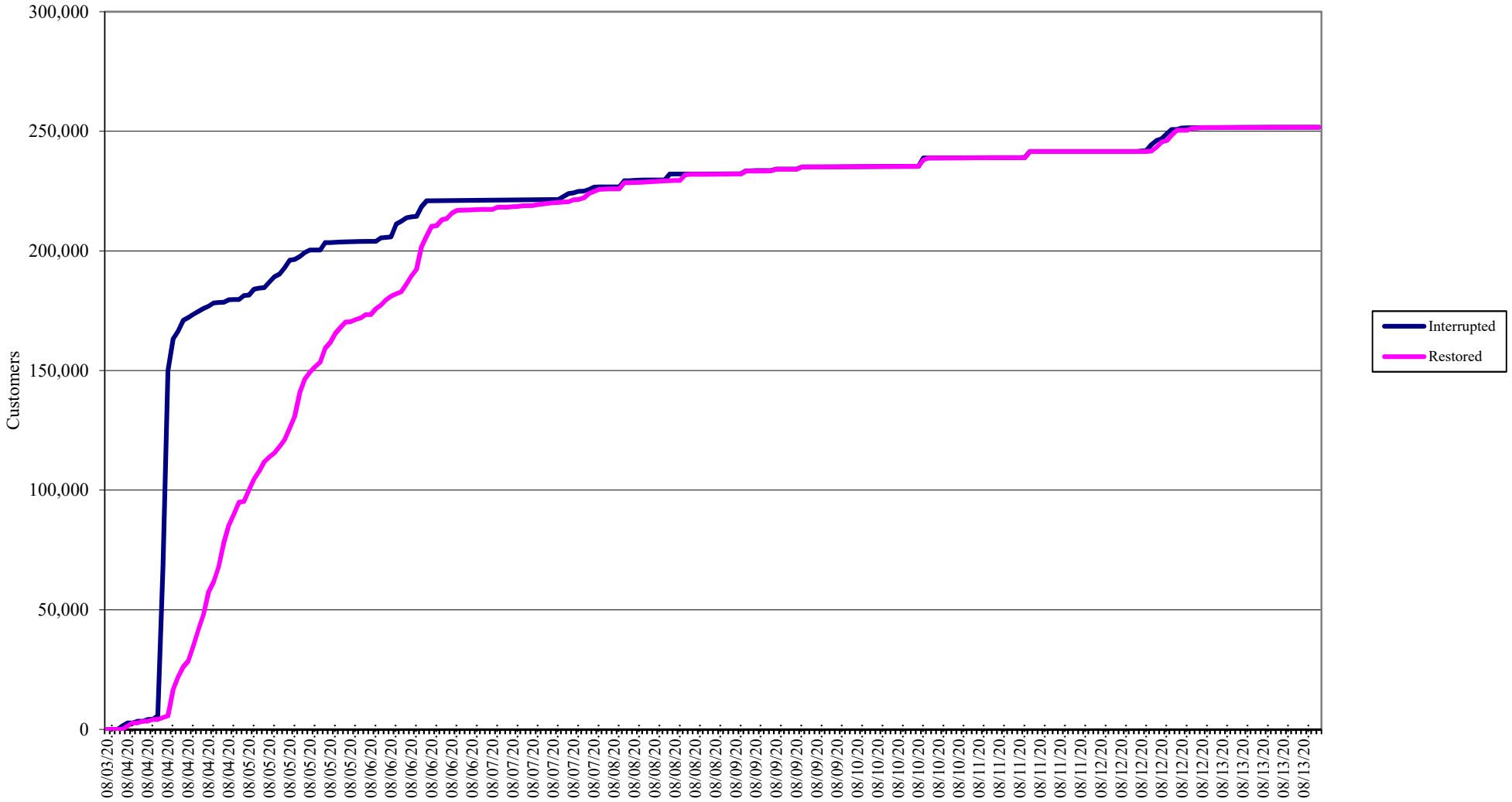
Attachment "C"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Metropolitan Division



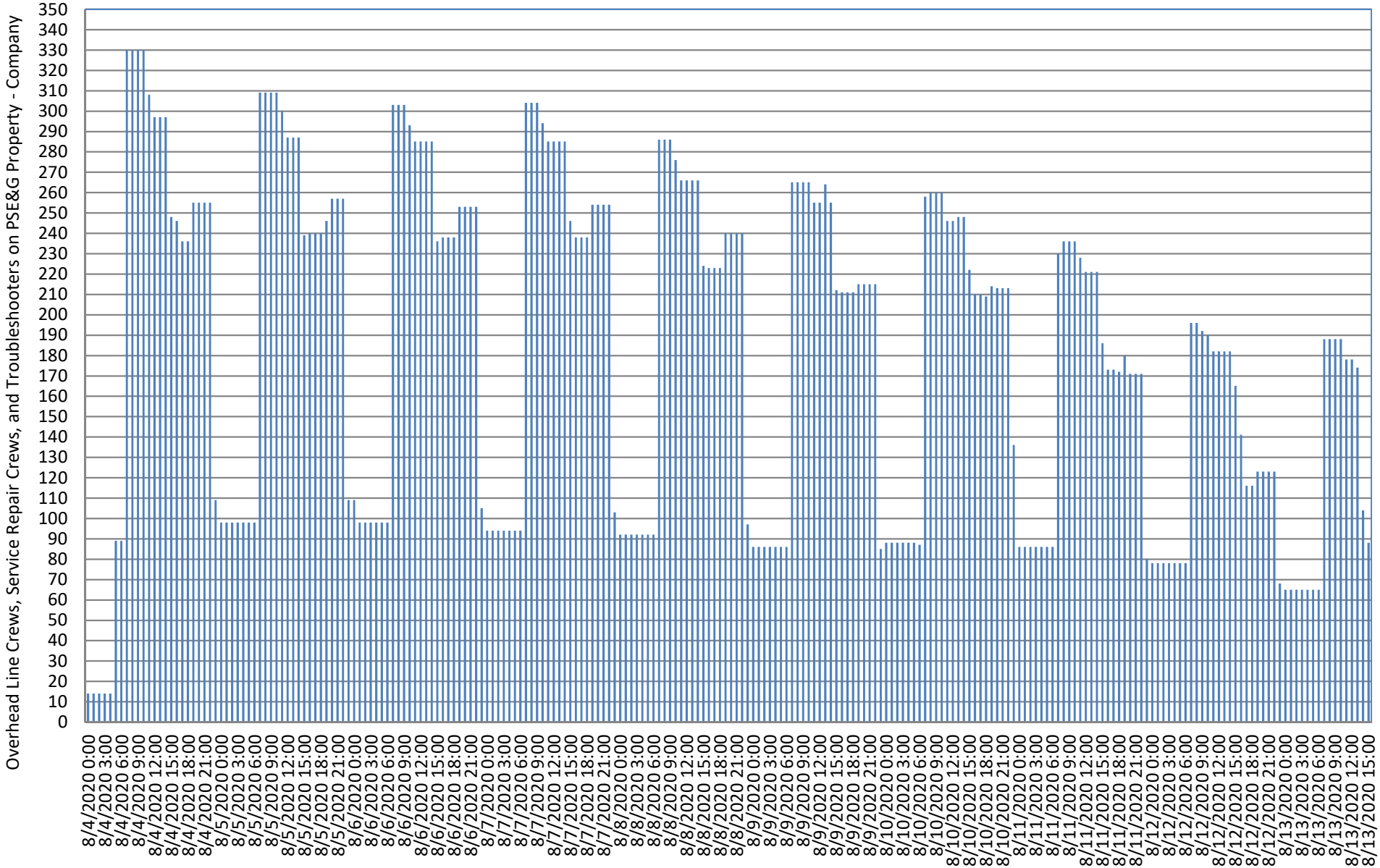
Attachment "D"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020
Southern Division

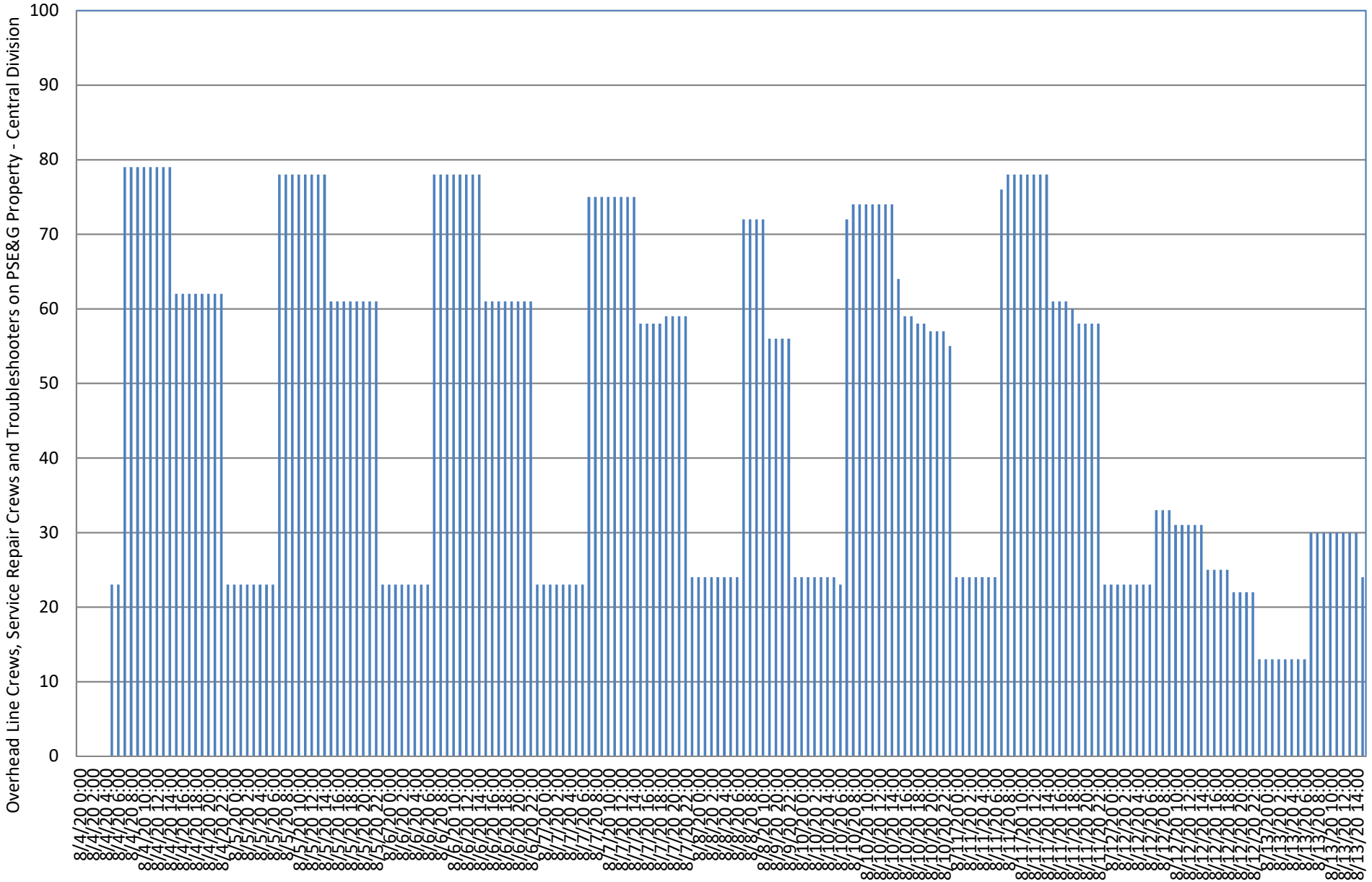


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

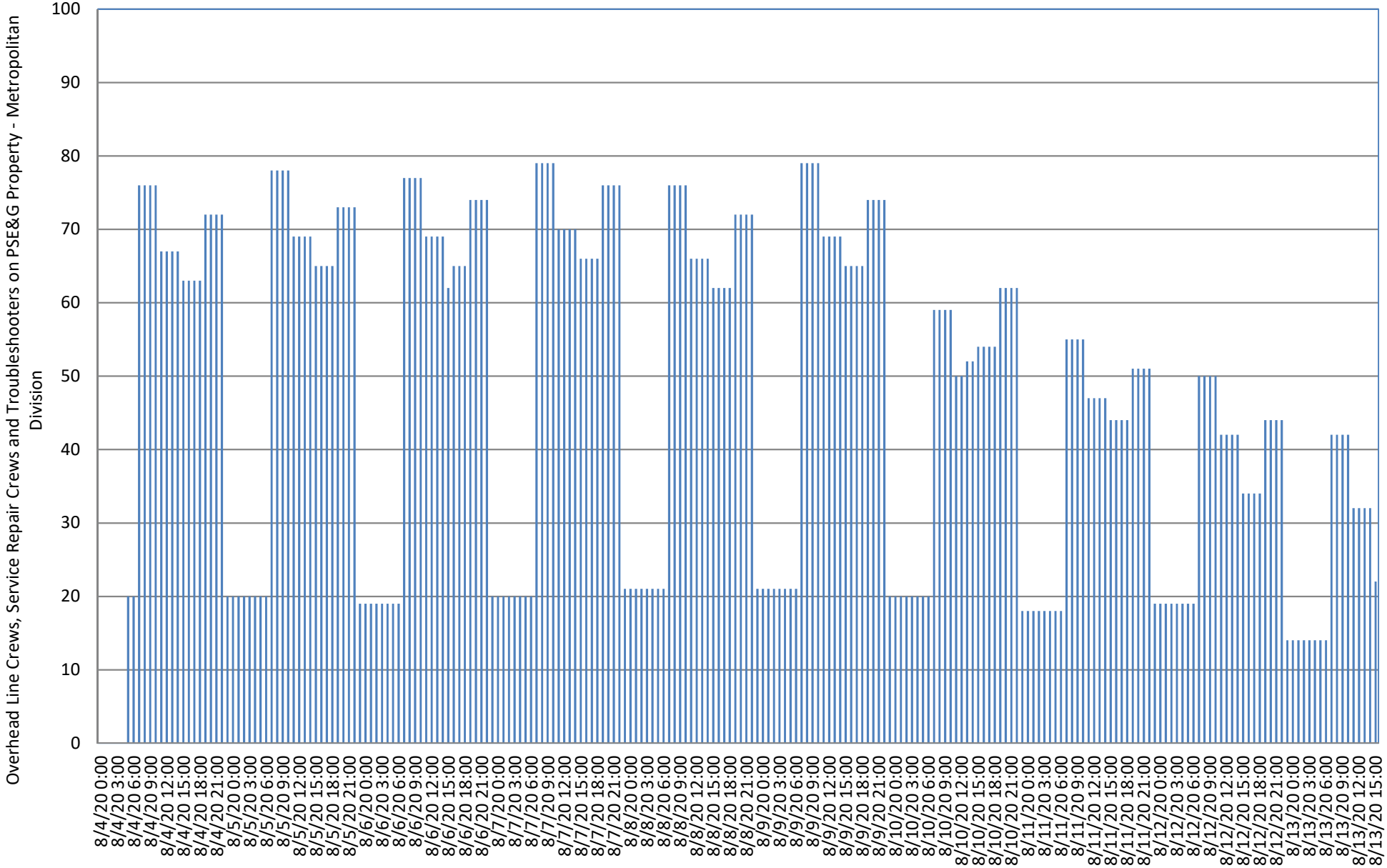


*These values include P&C Workforce Numbers

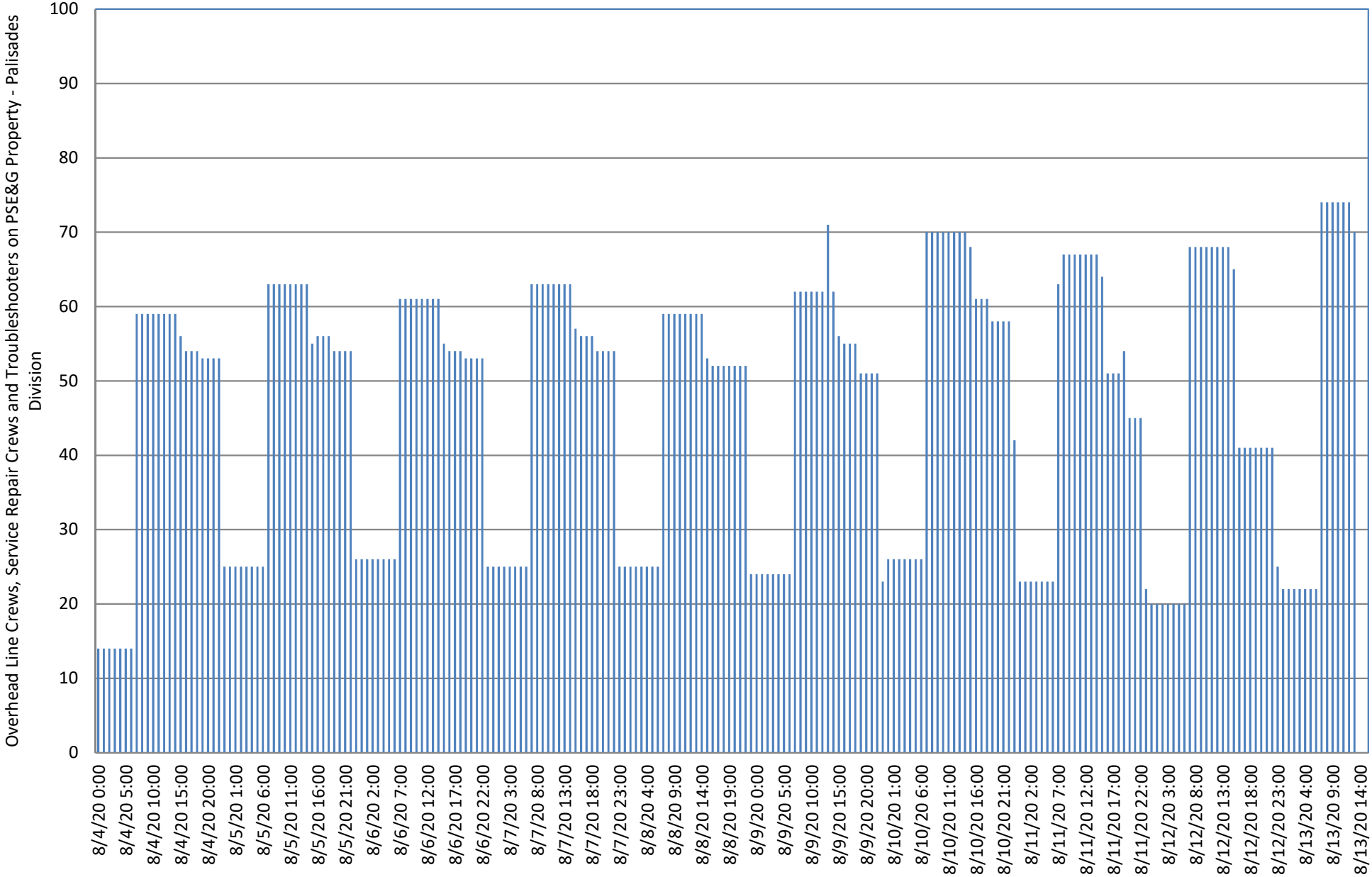
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



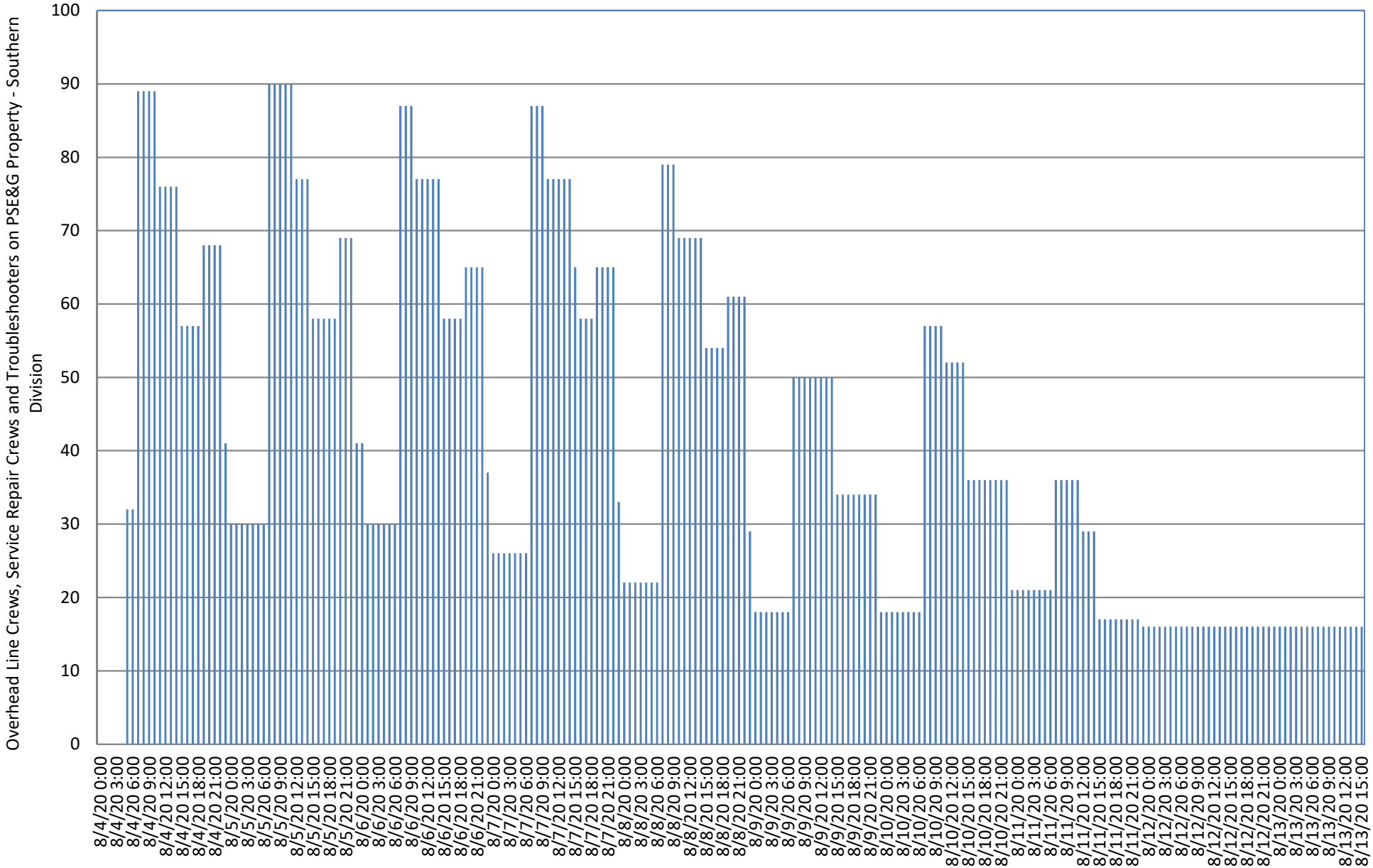
Attachment "H"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



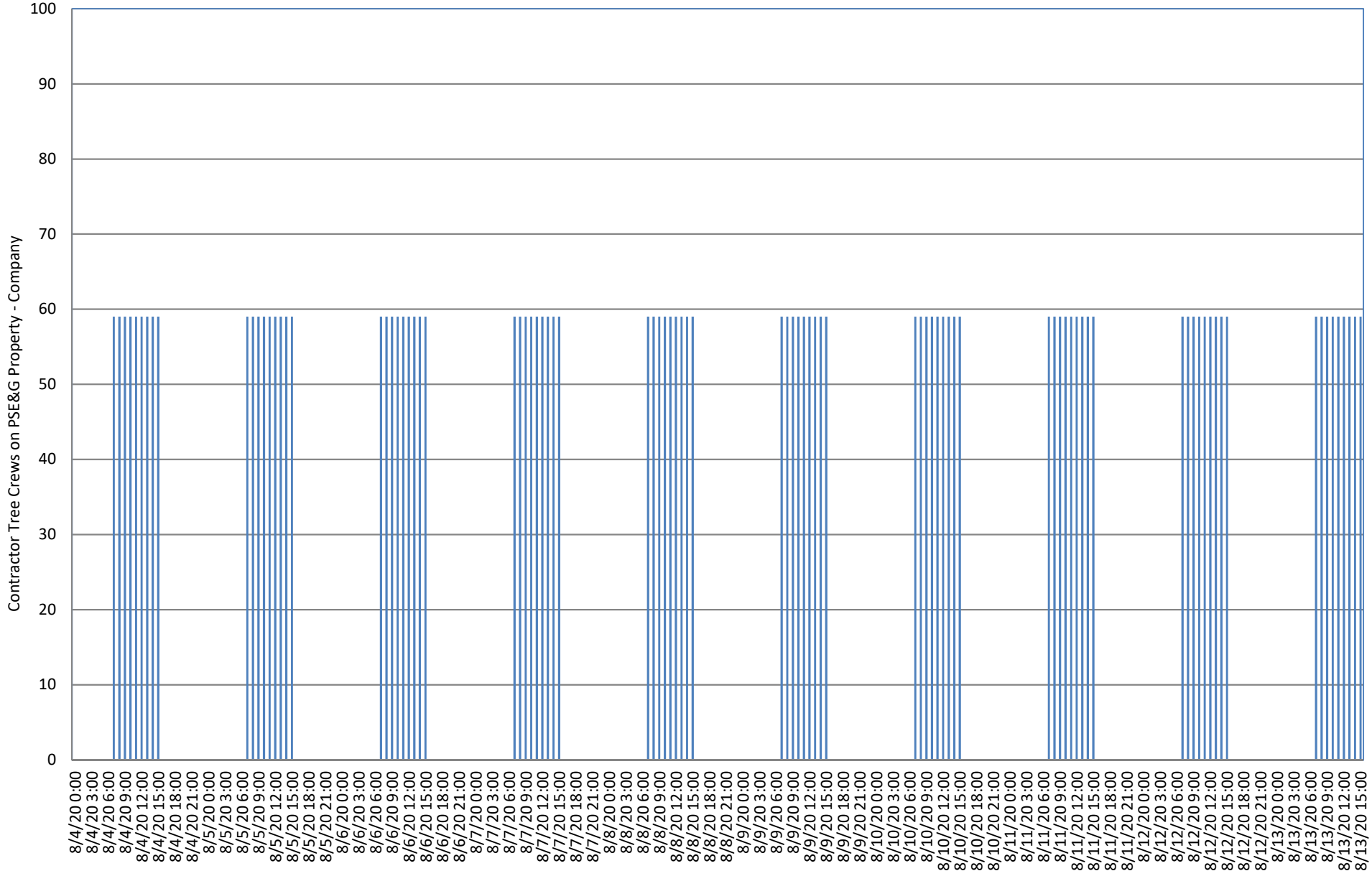
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



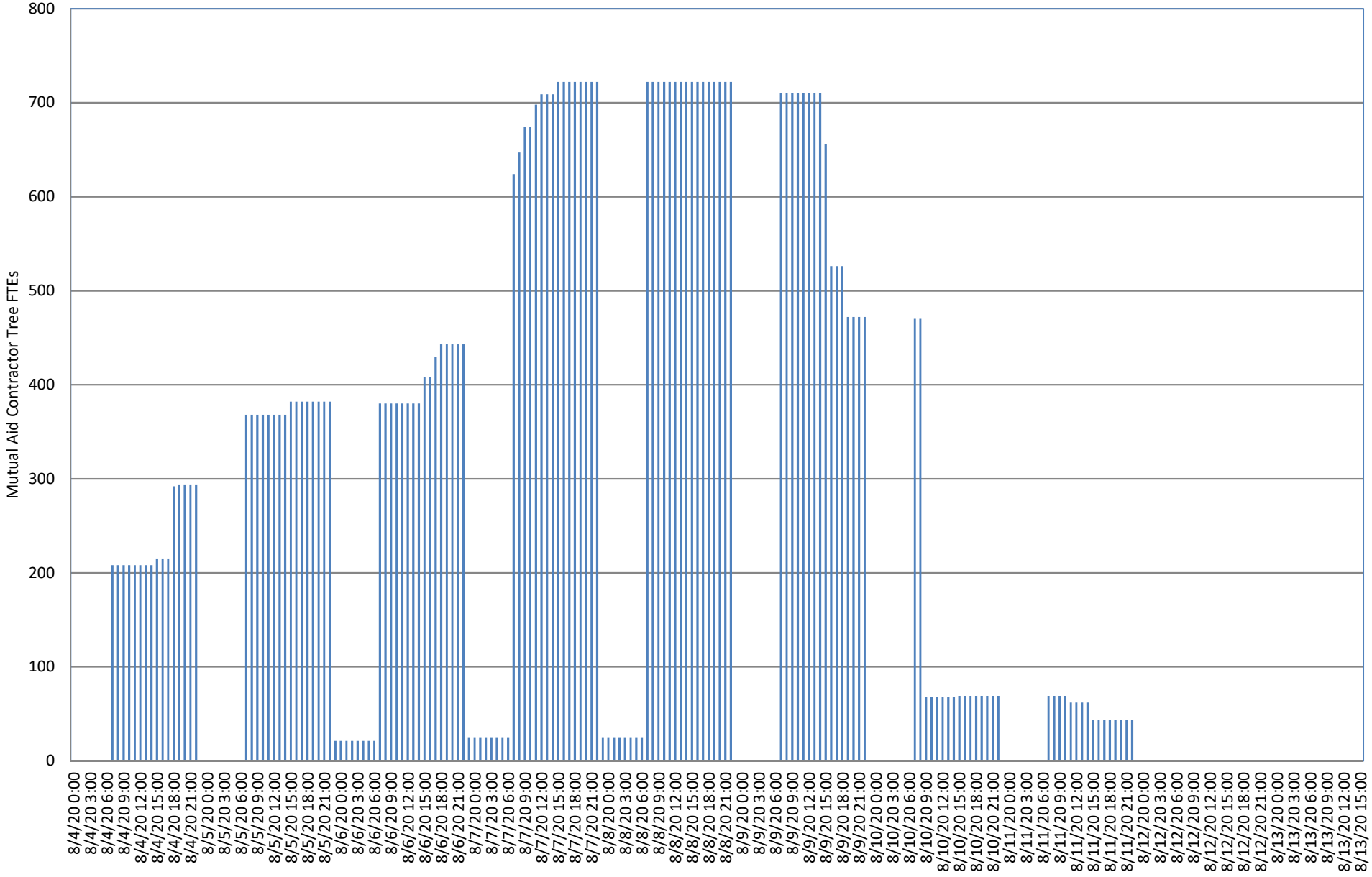
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



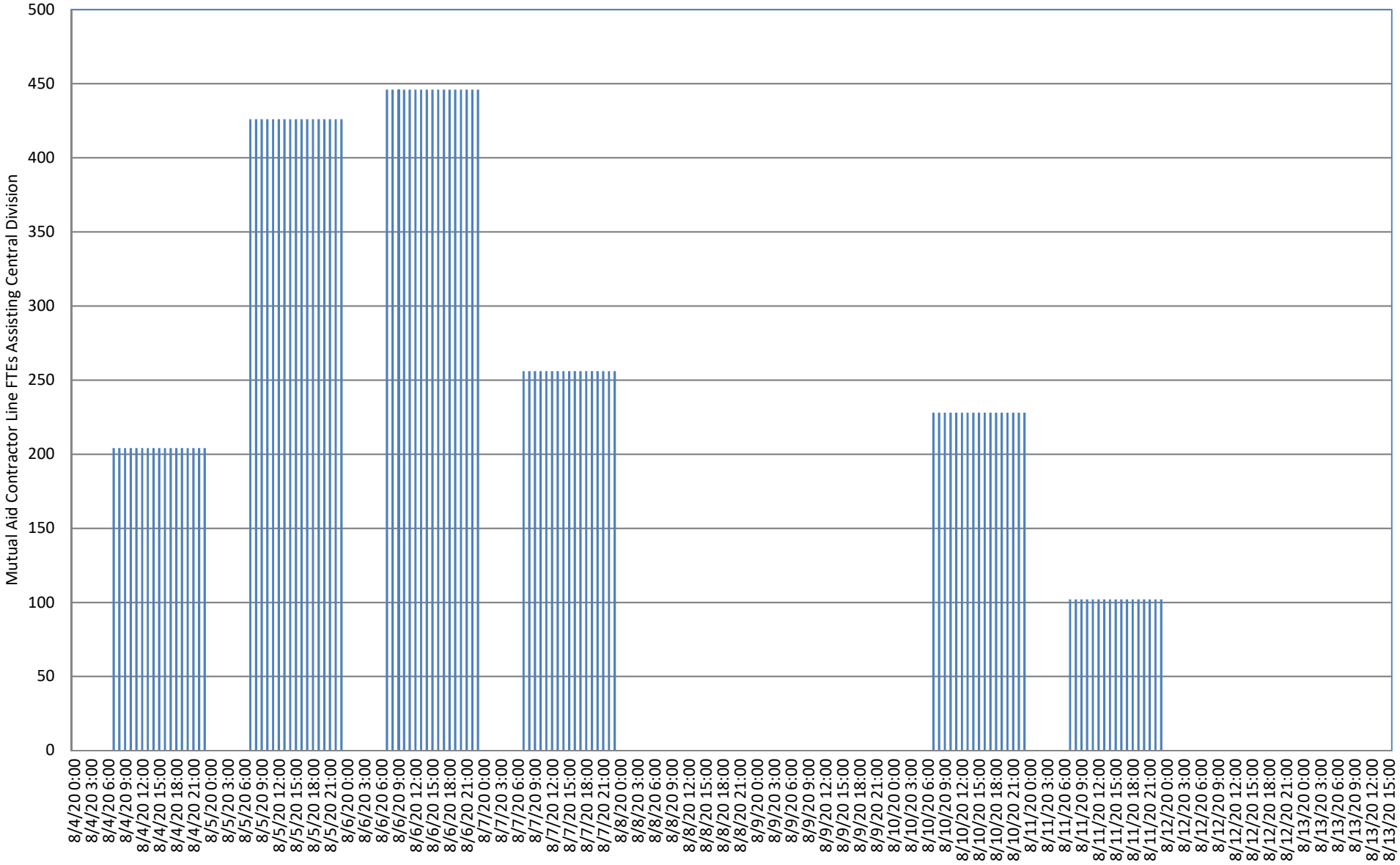
Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "L"
PSE&G
Mutual Aid Contractor Tree FTEs
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

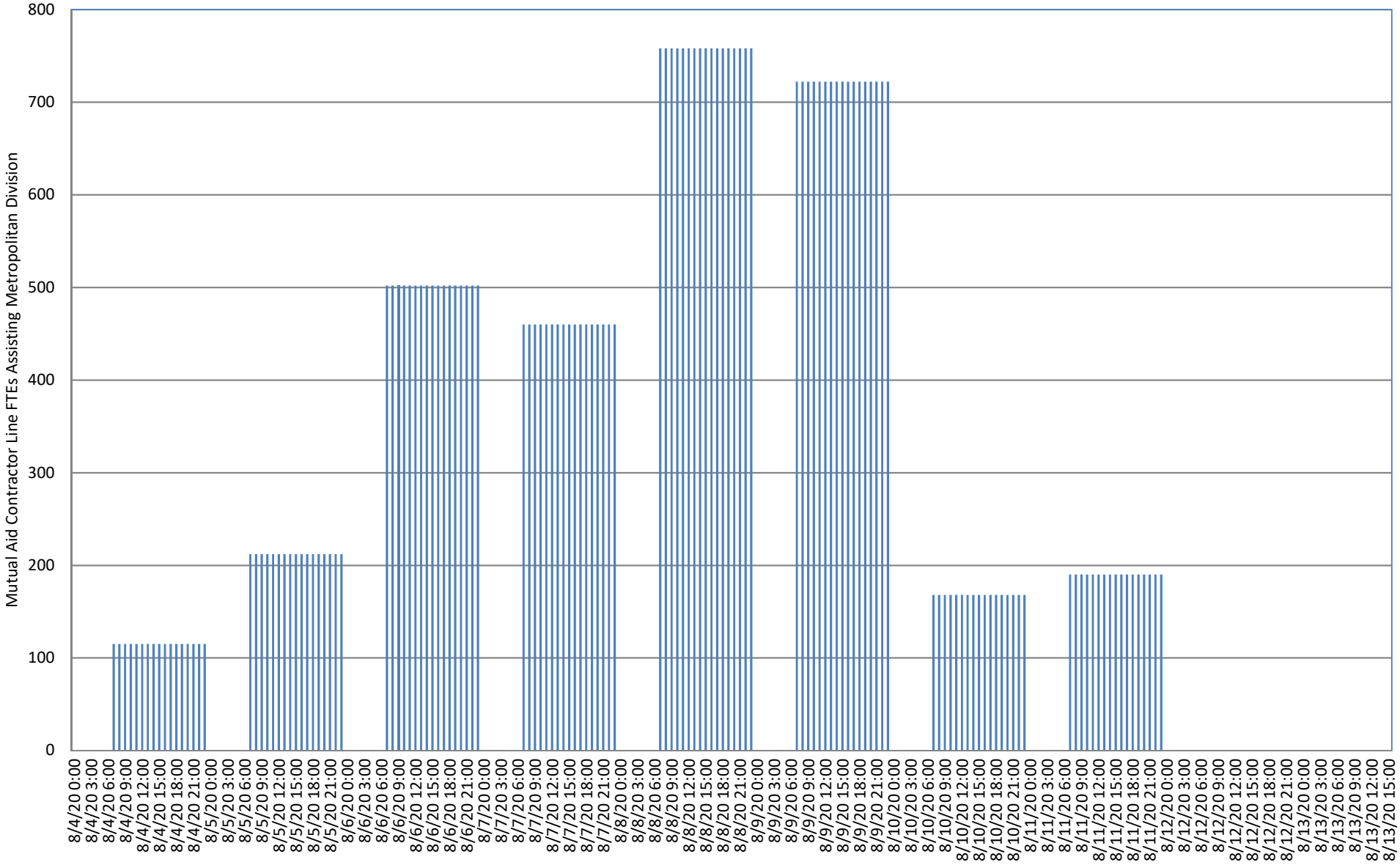


Attachment "M"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Central Division
Tropical StormIsaias, Mutual Aid to PSEG-LI, and State of Emergency - August 4-13,2020



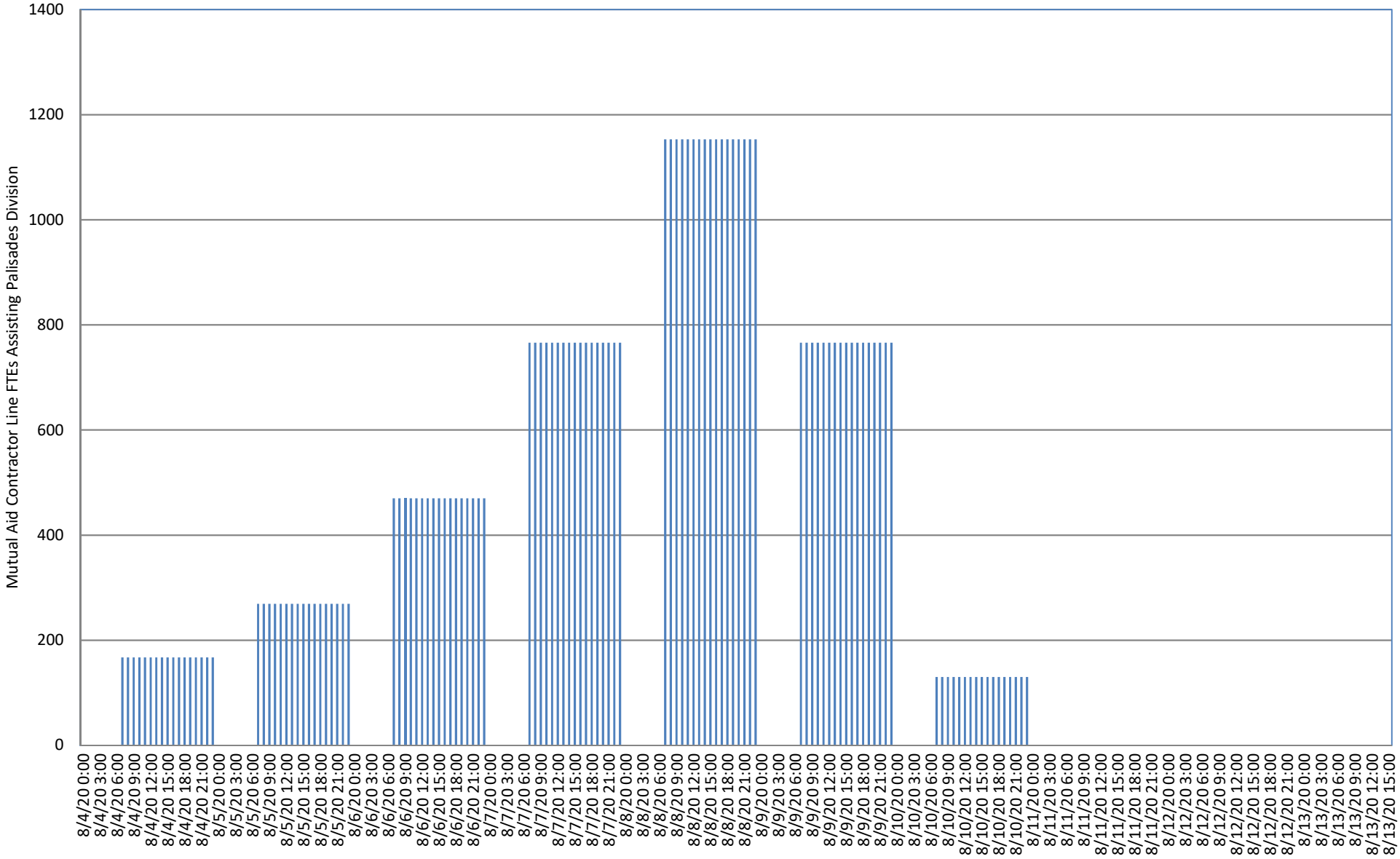
*These values include P&C Workforce Numbers

Attachment "N"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



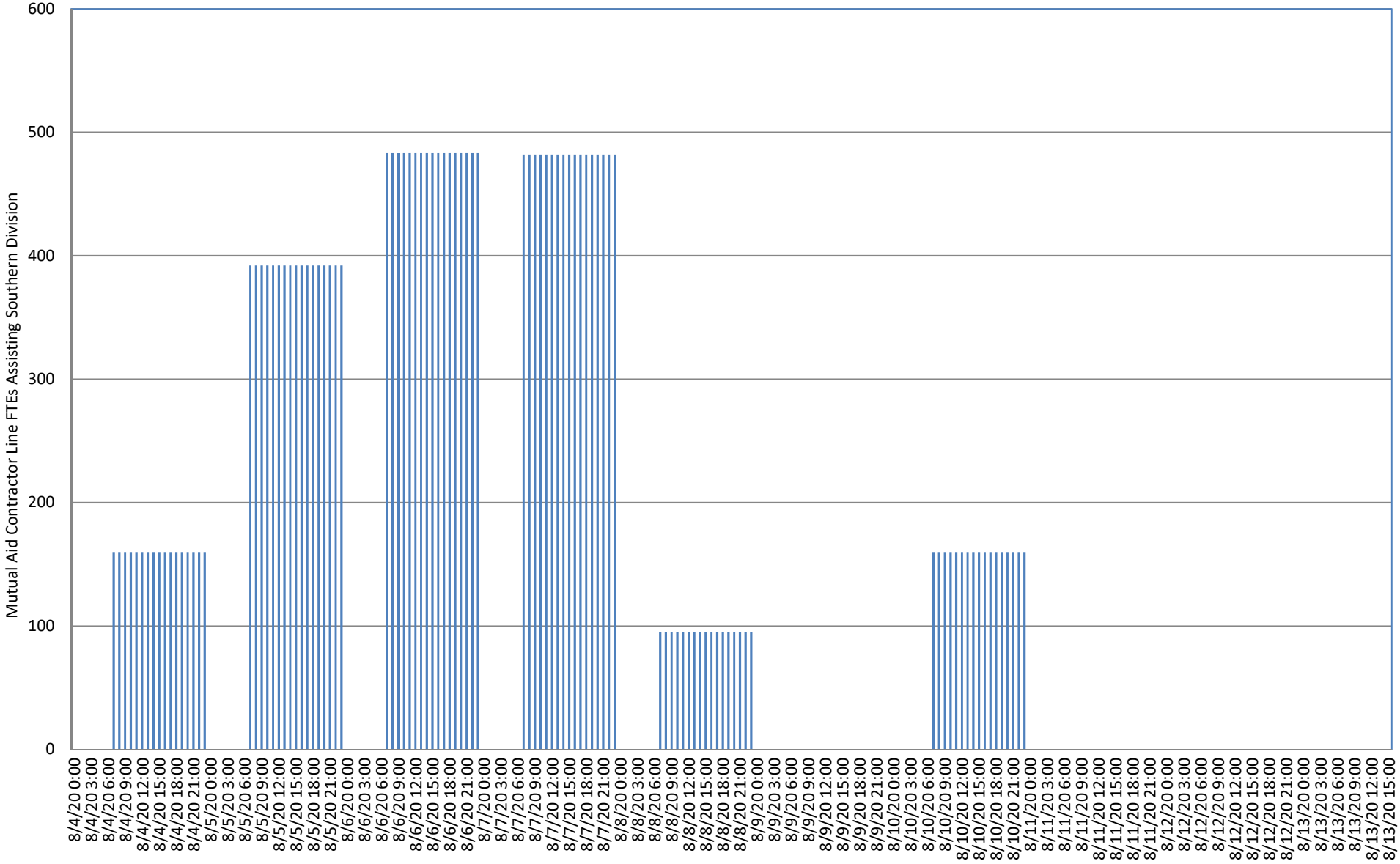
*These values include P&C Workforce Numbers

Attachment "O"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Palisades Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



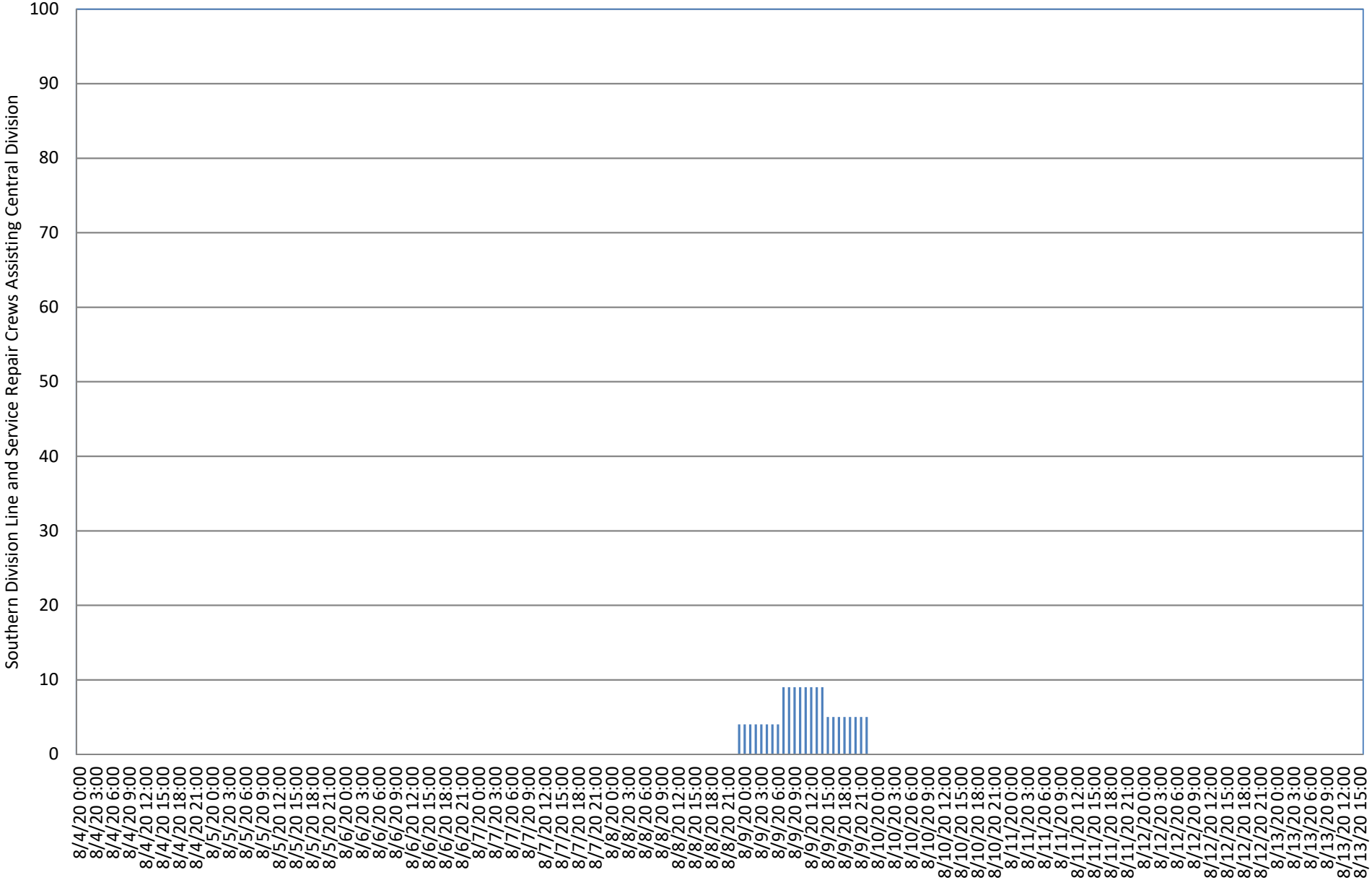
*These values include P&C Workforce Numbers

Attachment "P"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Southern Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020

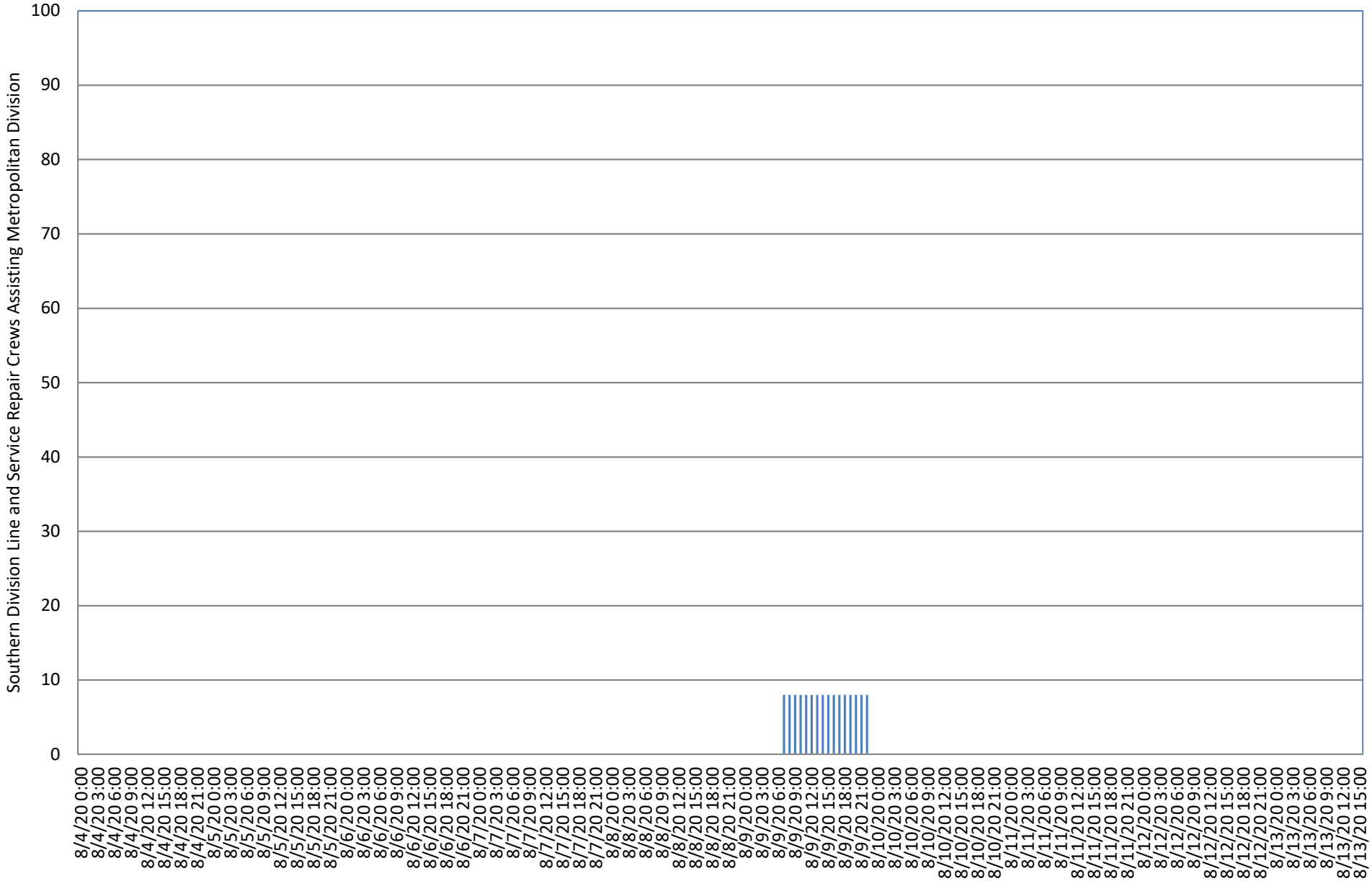


*These values include P&C Workforce Numbers

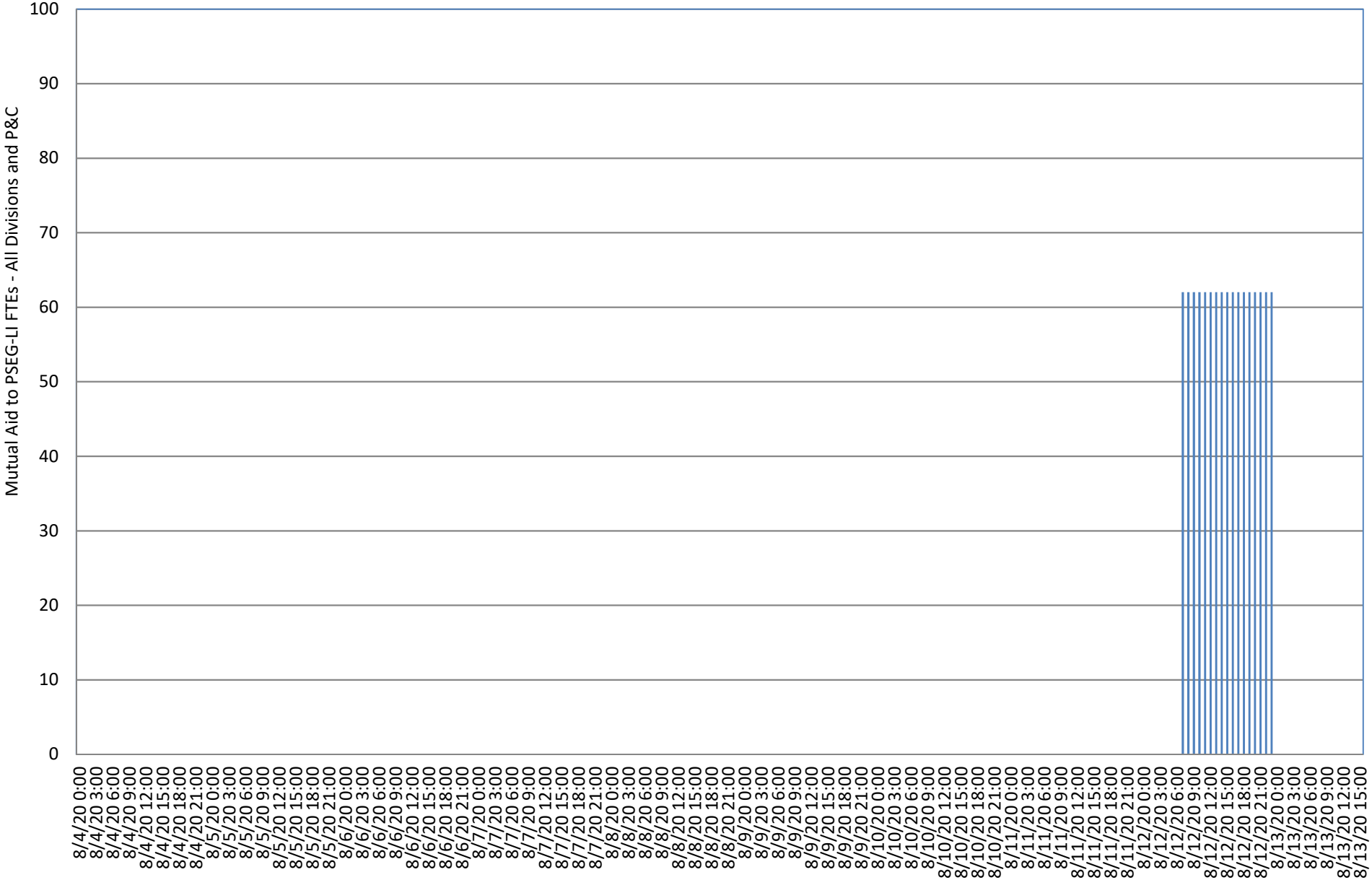
Attachment "Q"
PSE&G
Southern Division Line and Service Repair Crews Assisting Central Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "R"
PSE&G
Southern Division Line and Service Repair Crews Assisting Metropolitan Division
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



Attachment "S"
PSE&G
Mutual Aid to PSEG-LI FTEs - All Divisions and P&C
Tropical Storm Isaias, Mutual Aid to PSEG-LI and State of Emergency - August 4-13, 2020



PSE&G Hearing Statement

Wednesday, August 19, 2020 – 10 am
Zoom Meeting

Joint Meeting of the New Jersey Assembly Telecommunications and Utilities and Assembly Homeland Security and State Preparedness Committees

Good morning Chairpersons Assemblyman DeAngelo and Assemblywoman McKnight, and distinguished committee members. I am David Daly, President and Chief Operating Officer, PSEG Utility & Clean Energy Ventures, on behalf of Public Service Electric and Gas Company (PSE&G). I am joined at this meeting by Kim Hanemann, PSE&G's Senior Vice President and Chief Operating Officer. Thank you for inviting us to speak on behalf of PSE&G at this joint committee meeting regarding our preparation and response to Tropical Storm Isaias.

Introduction

When storms knock out power, it is our job to restore electricity in a timely and safe manner. Thankfully we are not in this alone, and PSE&G appreciates the support we received during the Isaias recovery from government officials, including the Governor's Office, the New Jersey BPU Staff, and the numerous county and municipal officials we work with preparing for and responding to major storm events.

Still, we realize our customers count on PSE&G to respond in storm conditions. We recognize the challenges this storm presented to our customers, and we regret the hardship and inconvenience this event may have caused. Isaias was a particularly destructive tropical storm. As with every storm there is significant work that happens after the last customer is restored, and that work has been on-going since our last customers in New Jersey were restored on August 11, 2020. We have now begun, and over the next several weeks we will complete, an After Action Review (AAR) to evaluate our preparation and restoration performance, and identify strengths as well as areas for improvement. As we have in the past, we will be working closely with the New Jersey Board of Public Utilities to evaluate our storm response, document lessons learned, and continuously improve performance.

In my introductory remarks today I would like to briefly: provide an overview of PSE&G's outage restoration efforts; summarize the preparation and response process, including securing foreign crews in the age of COVID; describe how our transmission and storm hardening distribution system investments fared during Isaias; and acknowledge issues observed with respect to our communications systems.

Tropical Storm Isaias Response Overview

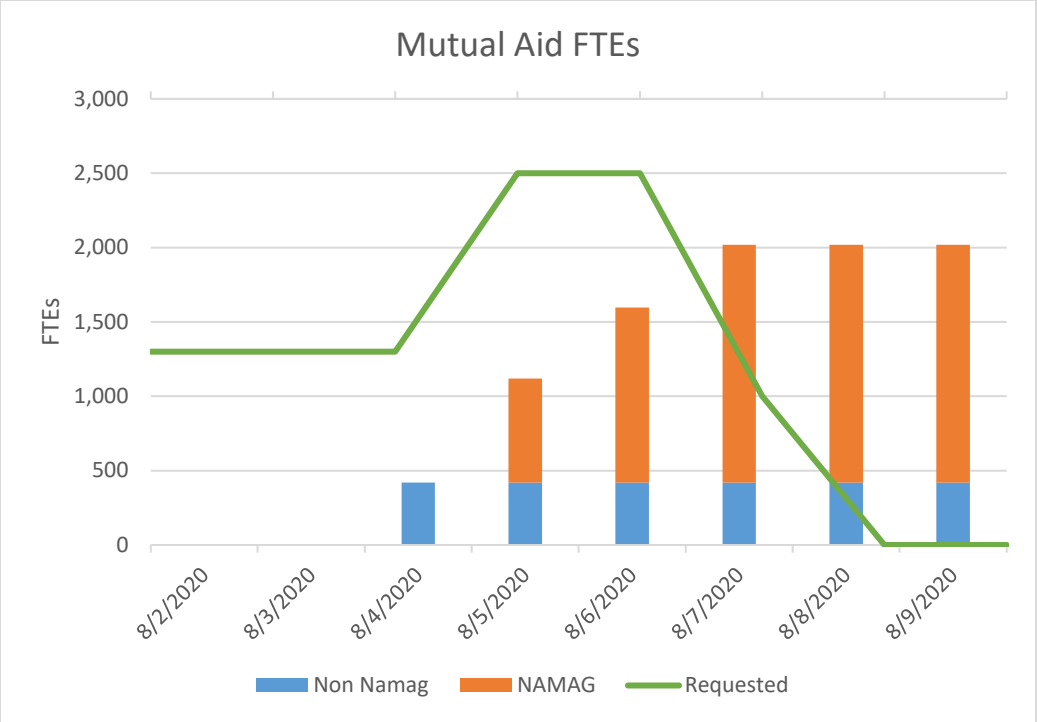
While there are always lessons to be learned, PSE&G believes that the storm preparation and response generally went well. Isaias was an extremely fast-moving tropical storm, and resulted in approximately 575,000 customer outages, with 26,000 jobs to be addressed in PSE&G's service territory. This included work on damaged outside plant facilities such as sub-transmission, primary and secondary conductors, individual services, broken poles and, of course, lots of tree clearing due to the high winds and rain associated with this storm.

The overall numbers are impressive, and reflect the hard work of our dedicated employees, contractors, and other participants in this all-hands-on-deck process. Within 24 hours after the storm hit, 48% of our impacted customers – approximately 276,000 customers -- had been restored. Within 48 hours, the figure was 75%, or approximately 430,000 customers; within 72 hours, 90% of customers who had been out – approximately 517,000 – had been restored. And within 92 hours – just four days – 96% of our affected customers, or approximately 552,000, had been restored.

Storm Preparation – Mutual Aid and COVID Protocols

PSE&G began preparation for Isaias on Thursday, July 30. Since Tropical Storm Isaias was a multi-state event that interrupted more than six million customers across a huge area, there was limited availability of line workers from mutual aid groups, and mutual aid crews were a minimum of 2-3 days travel time away since many of the resources initially secured came from contractors in areas not affected by the hurricane, such as Florida, Nova Scotia and the Midwest. While PSE&G initially requested 300 line workers through the traditional North Atlantic Mutual Assistance Group (NAMAG) process on Friday July 31 and an additional 1,300 FTEs over the weekend, NAMAG resources did not begin to arrive – in smaller numbers than we had requested -- until Tuesday evening, August 2.

Nevertheless, by aggressively reaching out early on to contractors, we were able to obtain 420 FTEs by August 4, allowing work to begin soon after the storm hit. PSE&G continued to secure additional crews throughout the storm and by Saturday August 8, had obtained 2,019 line mutual aid FTEs, and contracted over 200 FTEs for Damage Assessment and 1,000 FTEs for Vegetation Management, with crews arriving from Wisconsin, Louisiana, Maryland, Oklahoma, Indiana, Illinois, Florida, Louisiana, Maryland, Pennsylvania, Iowa, Kentucky, Michigan, Missouri, Alabama, and Nova Scotia. We utilized managers and professionals from across the Enterprise to manage these crucial resources.



A robust multi-dimensional communication and stakeholder engagement plan was planned in advance and implemented for the duration of the storm. In addition to our reoccurring daily media advisory updates designed to keep our customers, elected officials and other critical stakeholders appraised of the ongoing restoration efforts, PSE&G held daily calls with local, state and federal elected officials. Local Offices of Emergency Management were provided with dedicated liaisons as requested. Proactive outreach was initiated to our Life Support (P4) customers. Communications with these customers continued throughout the storm via phone calls regarding updated estimated restoration times.

COVID Impact

Like everything else in our current lives, preparation and response to Isaias was complicated by the continuing pandemic plaguing our nation, particularly in light of the large number of crews from outside of New Jersey required to adequately respond to this event. Well in advance of Isaias, PSE&G had considered this and developed a Storm Pandemic Plan which was implemented for Tropical Storm Isaias, including a set of protocols to be followed by storm crews and a strategy for ensuring those protocols were followed. Independent assessments of the COVID-19 mitigation protocols were conducted at identified field locations on a daily basis by trained observers, who communicated their findings to site leaders and coordinators, and also to PSE&G leadership.

Restoration Performance -- Benefits Of Prior Infrastructure Hardening

PSE&G employs a multi-step process in prioritizing its power restoration efforts. Early in the storm event we establish lists of critical customers (e.g., hospitals, nursing homes, police and fire

facilities, customers with life-sustaining equipment) to prioritize those repairs while in parallel prioritizing repairs to transmission lines and substations; our goal is to restore power to the greatest number of customers in the shortest possible time, while prioritizing our most critical customers. For example, we'll make repairs that restore power to 1,000 customers before a repair that would return electricity to 100 customers. Finally, we continue to work 24/7 to restore power to smaller neighborhoods and individual homes or businesses until the power is back for everyone.

On the transmission portion of the system – that is, the higher voltage cables that move power around our service territory -- the news is very good. First, the bulk transmission system (BTS) – including the large "backbone" projects PSE&G has constructed over the past decade, particularly in the years since Superstorm Sandy – held up extremely well. There were only 4 momentary incidents on the BTS which occurred due to flying debris, and there were no transmission-related incidents that resulted in any extended customer outages.

Results were similarly positive for the 69kV portion of the transmission system. In recent years we have been replacing the physically and technologically aging 26kV portion of our system, and upgrading to a modern, networked 69kV system using, generally, larger and stronger poles and stronger circuits. There were very limited problems with the 69kV facilities; only 8,200 customers experienced any type of outage related to our 69kV capital program, and these outages were resolved early in the process, on August 4.

Similarly, the flood mitigation work done beginning in 2014 under the Energy Strong and base capital programs withstood this test. Since this program began we have raised 32 stations, and when storm surge was checked against these stations no precautions were required. This enabled our team to focus on other important preparation activities. The Contingency Reconfiguration program in Energy Strong supported keeping customers in service or reducing outage durations for the 260 critical facilities completed as part of those projects. In addition, the Advanced Technology investments approved by the Board and executed by PSE&G in the Energy Strong effort performed well. Energy Strong upgrades to SCADA and station relaying allowed for remote operation and set-up for work in support of mutual aid, as designed. In other words, this investment enabled PSE&G to remotely operate our system so workers could safely repair and replace damaged infrastructure. Without this investment, we would have had to send workers to substations to operate station breakers to allow workers to work safely. Based on the Energy Strong projects, PSE&G was able to immediately identify issues on over 300 circuits and utilized the remote capabilities to support circuit restoration; during the peak of the restoration effort (August 6 to August 8), PSE&G successfully restored each day more than 1,300 outage incidents, each affecting multiple customers.

Also with regard to infrastructure improvement, I note that the type of outside plant work that PSE&G has unsuccessfully sought approval for in its Energy Strong requests could have, if implemented in a widespread manner, further reduced the damage and outage impacts of Isaias. This includes modern spacer cable configurations and pole upgrades for overhead distribution circuits, that would move the utility away from traditional, more vulnerable, cross-arm construction. This construction is more resistant to tree damage, which is the primary cause of outages in extreme weather events.

Putting aside our improved infrastructure itself, other aspects of the storm response also went well. Critical material such as poles, transformers, cable and wire was available from key suppliers per their contractual requirements. Improved communication between Staging Areas – which are like "mini-headquarters" for the response efforts -- and Mutual Aid Coordinators increased our efficiency. As we have in the past, PSE&G established several comfort stations throughout the service territory to supply ice and water to impacted customers.

Finally, tree outages are typically the leading cause of outages in a major event and this storm was no different. PSE&G has maintained a four year cycle for our vegetation management program in accordance with New Jersey Administrative Code requirements, including the removal of overhanging vegetation in the lock-out zone. To potentially improve our program we are piloting different mapping technologies to find encroachments outside of the program cycle as well. We are open to any discussion the Board may want to consider to enhance its vegetation management regulations intended to reduce outages during extreme weather events.

Communications And OMS

Through our elected official calls we learned that customers felt our automated communications that are generated from the Outage Management System required improvement. Currently, we do not know if an individual customer has power, and must rely on our Outage Management System (OMS) to evaluate individual customer circumstances. The OMS uses a number of criteria to drive messages to our customers. Unfortunately without knowing if the customer has power, the system makes assumptions and sends multiple messages regarding the status of power and estimated time to restore. The current system is not equipped with an advanced two-way information network, including smart meters at customer homes, capable of assessing remotely, and at frequent intervals, whether there is service interruption.

The PSE&G OMS issues experienced during the storm, we believe, led to very heavy call center volume. During normal non-storm conditions, for 2020, our call centers average approximately 260,406 agent handled calls per month. On the first day of the storm, the call center received more than a month's worth of calls -- 351,230 -- and answered 330,696 (308,263 with technology and 22,263 by Agents). Over the course of the storm we handled 635,128 calls (530,557 with technology and 104,571 by Agents).

Customers trying to communicate with us, particularly on the first day of the storm, were very challenged, and PSE&G recognizes that this is an area for follow-up and improvement. Better real-time outage information at a customer premise – which will be easily available after the implementation of AMI throughout our service territory -- would help customer communications drastically and also make the storm restoration process more efficient. Currently, to determine if a single customer has power, we have to physically visit the premise, call the customer, or rely on the customer to call us. In the last two days of a storm, when the majority of our efforts are focused on single service outages, the restoration effort would be much more efficient if the Company knew which customers were off-line. Customer-level outage data made available

through AMI would reduce physical site visits and customer phone calls, improve system outage modeling, and reduce the time it takes to restore customers.

Next Steps

We are well aware that we cannot rest upon past successes, and that despite our very best efforts in this storm, there is always room for improvement. As I noted at the outset, we are conducting a thorough internal review to determine what went right, what went wrong, and why.

We also recognize that we're not in this alone -- the findings, observations, and recommendations from various stakeholders across New Jersey provide an opportunity for effecting improvements to benefit customers. Our Senior Leadership Team, and all of our local, caring, and dedicated employees, are committed to cooperating and collaborating with the Legislature , as well as the Board of Public Utilities, and other stakeholders, on implementing recommendations that will improve and enhance our storm response and restoration process.

Thank you very much for your time.

		8/4 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**6,161,739**	**20,966,975**	**27,128,713**	**10,221,019**
2	Contractor/Mutual Aid	23,340,682	46,676,688	70,017,370	46,676,688
3	Tree Removal	3,045,794	8,645,999	11,691,794	8,645,999
4	Buses	-	-	-	-
5	Other Contractor	3,325,313	3,824,478	7,149,792	3,824,478
	Total Contractor	**29,711,790**	**59,147,166**	**88,858,955**	**59,147,166**
6	Material	**5,301,618**	**225,030**	**5,526,648**	**198,757**
7	Food	288,643	797,822	1,086,465	797,822
8	Lodging	489,111	1,384,101	1,873,212	1,384,101
9	Security	-	1,463	1,463	1,463
10	Water and Ice	-	566,932	566,932	566,932
14	Email Alerts	-	35,789	35,789	35,789
11	Other	154,611	444,768	599,379	21,948
	Total Other	**932,365**	**3,230,874**	**4,163,238**	**2,808,054**
	Total Incurred	**42,107,511**	**83,570,044**	**125,677,555**	**72,374,996**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**42,107,511**	**83,570,044**	**125,677,555**	**72,374,996**

Matthew M. Weissman
Managing Counsel - State Regulatory

Law Department
80 Park Plaza, T10, Newark, NJ 07102-4194
tel: 973.430.7052 fax: 973.430.5983
email: Matthew.Weissman@pseg.com

PSEG
Services Corporation

October 20, 2021

VIA ELECTRONIC MAIL ONLY

J. B. Cuartas, Director
Division of Reliability and Security
New Jersey Board of Public Utilities
225 East State Street - 2nd Floor, Area 2W
Trenton, New Jersey 08625

RE: MAJOR EVENT REPORT
STATE OF EMERGENCY - REMNANTS OF HURRICANE IDA - FLOODING
LOAD SHEDDING - EAST ORANGE
SEPTEMBER 1 - 28, 2021

Dear Director Cuartas:

As required by 14:5-8.8 Major Event Report, enclosed is a copy of PSE&G's Major Event Report for the State of Emergency – Remnants of Hurricane Ida - Flooding - Load Shedding - East Orange that affected PSE&G's entire service territory from September 1 - 28, 2021.

Questions concerning this matter can be directed to me or Donald W. Weyant, Manager - Regulatory Compliance at (973) 430-6730.

Very truly yours,

Matthew M. Weissman

Attachments

C (Email Only)
Joseph Fiordaliso, President
Upendra Chivukula, Commissioner
Bob Gordon, Commissioner
Mary-Anna Holden, Commissioner
Dianne Solomon, Commissioner
Paul Lupo, Acting Director

PSE&G'S REPORT TO THE BPU
MAJOR EVENT
STATE OF EMERGENCY - REMNANTS OF HURRICANE IDA
FLOODING - LOAD SHEDDING - EAST ORANGE
SEPTEMBER 1 - SEPTEMBER 28, 2021

EXECUTIVE SUMMARY

During the morning of September 1, 2021, PSE&G's entire service territory was affected by the remnants of Hurricane Ida. This weather system brought torrential rain to the state, which caused Governor Phil Murphy to declare a State of Emergency (SOE) at 2100 hrs. that evening. Heavy rains continued to fall over PSE&G's service territory, and the rest of the state, during the following three weeks. On September 28, after reviewing weather forecasts from PSE&G's private weather forecasters for the rest of the week, which did not predict any further heavy rain, PSE&G felt it was prudent to end this Major Event Report at 0800 hrs. on September 28, even though the SOE was still in effect. There were 215,192 customers that experienced extended interruptions during this event with 105,722 being interrupted on September 1 and 2 during the direct impact of the remnants of Hurricane Ida. PSE&G restored 99% of those customers within 48 hours.

PSE&G began preparing for this event on August 29, when a request for resource availability was received from the North Atlantic Mutual Assistance Group (NAMAG). The Southeastern Electric Exchange (SEE) was requesting assistance for southern utilities in anticipation of Hurricane Ida. On August 30, PSE&G decided not to release any PSE&G or contractor line FTES due to the predicted impact on PSE&G's service territory later that week. In addition, PSE&G personnel began to review the 72/48/24 hour storm preparation lists.

During PSE&G's 0800 hrs. daily operations call on September 1, PSE&G's weather forecaster predicted that the full impact of the remnants of Hurricane Ida would affect PSE&G service territory during that afternoon. At that time, PSE&G scheduled additional 1300 hrs. and 1900 hrs. conference calls for later that day and for succeeding days. In addition a 0830 hrs. staffing call was scheduled. Representatives from Electric Delivery's General Office Staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

During the 0830 hrs. staffing call, it was decided to schedule Electric Delivery personnel on a 2 / 3 - 1 / 3 schedule beginning at 1500 hrs. that day. Two thirds of the work force would work the 0700 – 2300 shifts while one third would work the 2300 – 1500 shifts. In addition, arrangements were made to patrol substations that are prone to flooding and to review the Stevens Institute of Technology flood model.

PSE&G was also able to move overhead line crews, underground crews and service repair crews between divisions between September 2 - 7 to address restoration efforts. These crew movements are included on the identified work force graphs. Damage assessors where also assigned to assist other divisions.

PSE&G opened its Emergency Operations Center (EOC) on the afternoon of August 29. It remained open in either virtual or fully activated mode until 1930 hrs. on September 3. This was the only time during these events that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on September 1. Liaison support provided was remote and continued until the OEMs closed. However, the Bergen County OEM requested in-person support on September 2 from 1000 - 1730 hrs. which was provided.

Conference calls with mayors and other municipal and elected officials were held on September 1, 2 and 3 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them, as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on August 31 and continued until September 28.

OPERATING REPORT

There were 215,192 customers that experienced extended interruptions during these events as listed below:

Division	# Customers Interrupted 9/1 - 9/2	Restoration	# Customers Interrupted 9/3 - 9/28	Final Restoration
Central	14,781	2225 - 9/3	17,113	0535 - 9/28
Metropolitan	55,780	1510 - 9/4	27,955	0718 - 9/28
Palisades	11,036	0751 - 9/4	28,567	0741 - 9/28
Southern	24,125	1407 - 9/4	35,835	0800 - 9/28
	105,722		109,470	
Grand Total	215,192			

Attached are the following Customer Restoration Summary Graphs for these events:

Attachment “A” - Company Wide
Attachment “B” - Central Division
Attachment “C” - Metropolitan Division
Attachment “D” - Palisades Division
Attachment “E” - Southern Division

During the morning of September 1, 2021, PSE&G’s entire service territory was affected by the remnants of Hurricane Ida. This weather system brought torrential rain to the state, which caused Governor Phil Murphy to declare a State of Emergency (SOE) at 2100 hrs. that evening. Heavy rains continued to fall over PSE&G’s service territory, and the rest of the state, during the following three weeks. On September 28, after reviewing weather forecasts from PSE&G’s private weather forecasters for the rest of the week which did not predict any further heavy rain, PSE&G felt it was prudent to end this Major Event Report at 0800 hrs., on September 28, even though the SOE was still in effect. There were 215,192 customers that experienced extended interruptions during this event with 105,722 being interrupted on September 1 and 2 during the direct impact of the remnants of Hurricane Ida. PSE&G restored 99% of those customers within 48 hours.

PSE&G began preparing for this event on August 29, when a request for resource availability was received from the North Atlantic Mutual Assistance Group (NAMAG). The Southeastern Electric Exchange (SEE) was requesting assistance for southern utilities in anticipation of Hurricane Ida. On August 30, PSE&G decided not to release any PSE&G or contractor line FTES due to the predicted impact on PSE&G’s service territory later that week. In addition, PSE&G personnel began to review the 72/48/24 hour storm preparation lists.

During PSE&G’s 0800 hrs. daily operations call on September 1, PSE&G’s weather forecaster predicted that the full impact of the remnants of Hurricane Ida would affect PSE&G service territory during that afternoon. At

that time, PSE&G scheduled additional 1300 hrs. and 1900 hrs. conference calls for later that day and for succeeding days. In addition a 0830 hrs. staffing call was scheduled. Representatives from Electric Delivery's General Office Staff, the four operating divisions, Projects & Construction (P&C), the Electric System Operations Center along with personnel from other operating and staff departments of the Company were involved on this call as well as subsequent calls of this nature.

During the 0830 hrs. staffing call, it was decided to schedule Electric Delivery personnel on a 2 / 3 - 1 / 3 schedule beginning at 1500 hrs. that day. Two thirds of the work force would work the 0700 – 2300 shifts while one third would work the 2300 – 1500 shifts. In addition, arrangements were made to patrol substations that are prone to flooding and to review the Stevens Institute of Technology flood model.

PSE&G was also able to move overhead line crews, underground crews and service repair crews between divisions between September 2 -7 to address restoration efforts. These crew movements are included on the identified work force graphs. Damage assessors where also assigned to assist other divisions.

PSE&G opened its Emergency Operations Center (EOC) on the afternoon of August 29. It remained open in either virtual or fully activated mode until 1930 hrs. on September 3. This was the only time during these events that it had to be activated.

Communications with 12 County Offices of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on September 1. Liaison support provided was remote and continued until the OEMs closed. However, the Bergen County OEM requested in-person support on September 2 from 1000 - 1730 hrs. which was provided.

Conference calls with mayors and other municipal and elected officials were held on September 1, 2 and 3 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them, as did the Senior Directors and other personnel from each of the four operating divisions.

Communications with Board staff began on August 31 and continued until September 28.

PERSONNEL DEPLOYMENT

Attached are the following Work Force Graphs for these events:

Attachment "F" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Company
Attachment "G" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Central Division
Attachment "H" - Overhead Line Crews, Underground Crews, Service Repair Crews and Troubleshooters – Metropolitan Division
Attachment "I" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Palisades Division
Attachment "J" - Overhead Line Crews, Service Repair Crews and Troubleshooters - Southern Division
Attachment "K" - Contractor Tree Crews - Company
Attachment "L" - Central Division Underground Crews Assisting Metropolitan Division
Attachment "M" - Palisades Division Underground Crews Assisting Metropolitan Division
Attachment "N" - Southern Division Overhead Line, Underground Crews and Service Repairs Crews Assisting Central Division.
Attachment "O" - Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Metropolitan Division
Attachment "P" - Mutual Aid Contractor Line FTEs Assisting Palisades Division
Attachment "Q" - Mutual Aid Contractor Line FTEs Assisting Metropolitan Division

A staging area for the Mutual Aid crews was established at the former Toys R Us site in Wayne.

As is standard operating procedure in system emergencies, liaison support to each of the four operating divisions was provided beginning on September 1. This remote support continued until September 3. Remote liaison support was provided to the two Inquiry Centers. These liaisons assisted in addressing customer inquiries.

Communications with 12 County Officers of Emergency Management (OEM) and the City of Newark's Emergency Management Center began on September 1. Liaison Support provided was remote and continued until the OEMs closed. However, the Bergen County OEM requested in-person support on September 2, from 1000 - 1730 hrs. which was provided.

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside plant damage locations are listed below:

69 & 26-kV	- 37
13 & 4-kV	- 596
Transformers	- 155
Secondaries	- 62
Services	- 247
Poles	- 197
Trees	- 234
Total	1,528

COMMUNICATIONS

Communications with Board staff began on August 31 and continued until September 28.

PSE&G's Corporate Communications Department issued internal communication press releases and handled newspaper, television and radio information requests during these events.

PSE&G proactively utilized Social Media (Facebook, Twitter and LinkedIn) to communicate storm restoration information to customers during this event releasing 44 different messages. In addition, more than 1.6 million emails were sent to customers during this event informing them of storm restoration progress.

As required in Recommendation 3 from the Tropical Storm Isaias Board Order, the following standardized Call Center information is provided:

Date	Number of calls Offered (NCO)	Number of calls Handled (NCH)	Number of calls Abandoned (NCA)	Call Abandonment Rate (CA%)	Average Speed of Answer (ASA)
9/1/2021	33742	31487	2255	6.7%	56
9/2/2021	39762	36807	2955	7.4%	121
9/3/2021	33670	30191	3479	10.3%	230
9/4/2021	14997	14182	815	5.4%	88
9/5/2021	8911	8573	338	3.8%	47
9/6/2021	12250	11697	553	4.5%	92
9/7/2021	39076	35684	3392	8.7%	231
9/8/2021	26759	25172	1587	5.9%	114
9/9/2021	26116	25518	598	2.3%	27
9/10/2021	22742	22375	367	1.6%	16
9/11/2021	8863	8614	249	2.8%	46
9/12/2021	5472	5418	54	1.0%	5
9/13/2021	33477	30859	2618	7.8%	222
9/14/2021	24670	24128	542	2.2%	39
9/15/2021	25075	24086	989	3.9%	91
9/16/2021	21894	21110	784	3.6%	74
9/17/2021	20572	20092	480	2.3%	38
9/18/2021	8102	8020	82	1.0%	11
9/19/2021	4798	4759	39	0.8%	5
9/20/2021	26680	25120	1560	5.8%	156
9/21/2021	20394	19903	491	2.4%	40
9/22/2021	19439	19092	347	1.8%	32
9/23/2021	21445	21180	265	1.2%	10
9/24/2021	19257	18970	287	1.5%	17
9/25/2021	7162	7049	113	1.6%	18
9/26/2021	4911	4876	35	0.7%	6
9/27/2021	24935	23955	980	3.9%	107
9/28/2021	19404	19122	282	1.5%	23

A notification to PSE&G's critical needs (P-4) customers was issued on August 31 informing them of the impending storm and recommending precautions they should take. This information was also included in outbound calls made with Estimated Times of Restoration (ETRs).

Conference calls with mayors and other municipal and elected officials were held on September 1, 2 and 3 concerning storm restoration efforts. Members of the Regional Public Affairs (RPA) Department organized the calls and participated in them as did the Senior Directors and other personnel from each of the four operating divisions.

A North Atlantic Mutual Assistance Group (NAMAG) conference call was held on September 2 at 1030 hrs. PSE&G requested 100 FTEs but none were secured.

On September 3, PSE&G was able to secure 73 Contractor Line FTEs. They arrived at various times on September 3 and were released at 0700 hrs. on September 4. In addition, PSE&G utilized 41 Contractor Line FTEs already on the property.

INCIDENTS

Robert Wood Johnson University Hospital, Rahway

The hospital's service was interrupted on September 1 at 2051 hrs. The hospital does not have a back-up feed and transferred to their emergency generation. Investigation revealed that the outage was caused by a problem in the customer's electrical system. Once repairs were made by the customer, service was restored at 0930 hrs. on September 2.

NJ American Water - Island Farm, Bridgewater

This customer's 26-kV substation was interrupted on September 2, at 0910 hrs. when the main feed to the station, the K-89 locked out. The station did not transfer to the station's backup feed, the J-114. The K-89 was patrolled and no trouble was found. There was no access to the station due to flooding. Finally on September 3, the station was accessible and it was found that the K-89's motor operated disconnects failed to open due to a wiring problem, which is the customer's responsibility to repair. At 0700 hrs. that day, service was restored to the station by way of the J-114.

ROIC, Ewing

At 1653 hrs. on September 1, lightning burned down "B" phase on the ROIC's main supply circuit, LCE 8003, causing a part power condition at the facility. ROIC officials did not want to transfer to their back-up circuit, FEN 8041. They decided instead to remain on their emergency generation until LCE 8003 could be restored. PSE&G made repairs to LCE 8003 and the circuit was restored at 2251 hrs. that day.

Flooding

As a result of the flooding caused by the torrential rains associated with the remnants of Hurricane Ida, PSE&G had to disconnect electric service to customers in each of its four operating divisions as follows:

Central Division	-	1,325
Metropolitan Division	-	12
Palisades Division	-	69
Southern Division	-	14
Total	-	1,420

Services either have been reconnected or will be re-connected pending the appropriate municipal approvals.

As a result of its Energy Strong 1 Program, PSE&G raised or rebuilt facilities at 26 switching stations and substations that were impacted by Super Storm Sandy. Although water did enter eight of these substations, none of the 26 switching stations or substations where facilities were raised or rebuilt where interrupted by the floodwaters associated with the remnants of Hurricane Ida. In addition, seven substations affected by Super Storm Sandy have been eliminated.

Deptford / Woodbury Heights - Severe Wind Damage

During the early evening on September 1, severe winds struck seven areas of Deptford and Woodbury Heights causing extensive damage to PSE&G's overhead facilities. While the National Oceanic and Atmospheric Administration (NOAA) determined that the damage was not caused by a tornado, three tornadoes were verified in this general area. The most extensive damage occurred on Tanyard Road, Barlow Avenue, Willis Avenue and Logan Avenue in Deptford and on Glassboro Road, Lake Avenue and Walnut Avenue in Woodbury Heights.

Approximately 1,300 customers were interrupted at 1831 hrs. when the two circuits serving these areas, Deptford 8041 and Thorofare 8023, locked out. Over the next three days, a total of five line crews and approximately 25 tree crews worked in these areas restoring service. Approximately 4,500' of primary conductors, 20 poles, 20 pole top transformers and multiple house services were replaced. The final customer was restored on September 4 at 1407 hrs.

Central Avenue and Fifteenth Street Substations

At 2018 hrs. on September 1, Central Avenue and Fifteenth Street Substations in Newark were shut down interrupting 21,481 customers extendedly. Investigation revealed that water leaked through the roof of Central Avenue Substation on to the station's 26-kV bus causing a fault which shut the station down including the 26-kV feed to Fifteenth Street Substation.

After clearing the faulted equipment, Central Avenue Substation and Fifteenth Street Substation were restored to service at 2146 hrs.

Temporary repairs were made to the roof of Central Avenue Substation and a roofing contractor will make permanent repairs.

LOAD SHEDDING - EAST ORANGE - SEPTEMBER 1 - 2, 2021

EXECUTIVE SUMMARY

On September 1 at 2305 hrs., PSE&G had to manually shed load in a portion of East Orange by intentionally cutting out 4-kV circuit East Orange (EAO) 4020, interrupting 3,849 customers. That circuit is part of a three circuit network which also includes EAO 4004 and EAO 4025.

At 2023 hrs. on September 1, EAO 4004 locked out and at 2237 hrs., EAO 4025 locked out. PSE&G immediately began to monitor the load on EAO 4020. At 2305 hrs., PSE&G cut the circuit out before it exceeded its Summer Emergency Rating.

PSE&G immediately began to fault locate the underground failures on EAO 4004, EAO 4025 and EAO 4020. Three oil filled cutouts on EAO 4004 failed in a manhole in front of 256 Halstead Street, East Orange. An underground transformer failed on EAO 4025 in front of 50 South Munn Avenue, East Orange. An underground transformer failed on EAO 4020 on Halstead Street n/o Elmwood Avenue, East Orange.

After repairs were made to the failed equipment, EAO 4004 and EAO 4025 were energized at 2215 hrs. on September 2, restoring all 3,849 customers in the network to service. EAO 4020 was energized at 2231 hrs. restoring all three circuits in the network and putting the network back in normal operation.

Board staff was notified of this event on the morning of September 2 and notifications continued until September 3.

OPERATING REPORT

Extended customer interruptions and restoration times during this load shedding event are as follows:

Circuit	Time Out	Time Restored
EAO 4004	2023 - 9/1	2215 - 9/2
EAO 4025	2237 - 9/1	2315 - 9/2
EAO 4020*	2305 - 9/1	2231 - 9/2

*All 3,849 customers were interrupted when EAO 4020 was cut out at 2305 hrs. on September 1. All the customers were restored when EAO 4020 and EAO 4025 were cut in at 2215 hrs. on September 2. The customers are included in the Company and Metropolitan Division Customer Restoration Graphs.

PERSONNEL DEPLOYMENT

Personnel from various Metropolitan Division Departments were involved in this load shedding event and are included in the Company and Metropolitan Division work force graphs.

TROUBLE LOCATIONS

Underground oil filled cutouts - 1
Underground Transformers - 2

COMMUNICATIONS

A Regional Public Affairs Manager contacted the East Orange Chief of Staff on September 1 and this contact was maintained during this event.

PSE&G opened a customer care water and ice station for East Orange residents on September 3 at the East Orange City Hall.

SUMMARY

PSE&G promptly responded to this load shedding event. Once the second circuit in the network failed, the load on EAO 4020 was monitored and the circuit was cut out before it reached its Summer Emergency Rating.

There were no issues involving material or equipment during this load shedding event.

This load shedding event qualifies as a Major Event since this was action taken to maintain the adequacy on security of the electric system, including emergency load control and emergency switching.

UNDERGROUND CIRCUIT FAILURES - METROPOLITAN DIVISION

The severe flooding in Metropolitan Division associated with the remnants of Hurricane Ida caused an extraordinary amount of conventional underground circuit failures. There were 37 separate circuit failures that occurred during this event. Underground crews from Central, Palisades and Southern Divisions and underground crews from P&C were able to assist Metropolitan Division with fault locating and repair work. These forces are included in the respective work force graphs.

SUMMARY

Restoration efforts during these events went extremely well. PSE&G was well prepared to address the outages caused by the remnants of Hurricane Ida. During the direct impact of the remnants of Hurricane Ida on September 1 and 2, 105,722 customers experienced extended interruptions. PSE&G was able to restore service

to 99% of these customers within 48 hours. There were 215,192 customers that experienced extended interruptions during these events, which ended on September 28.

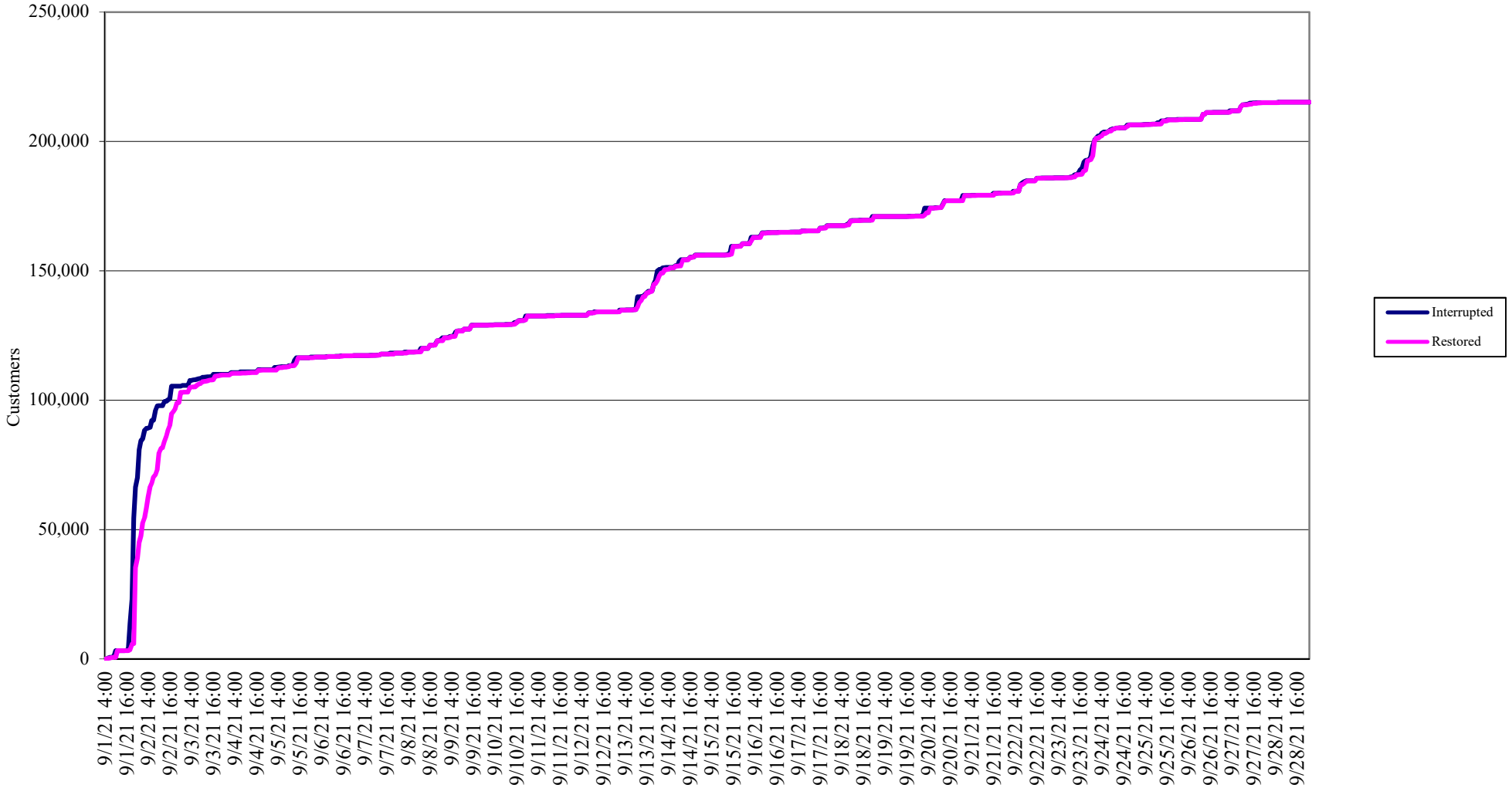
PSE&G's excellent relationships with its unions were beneficial during these events.

There were no issues involving equipment or material during these events.

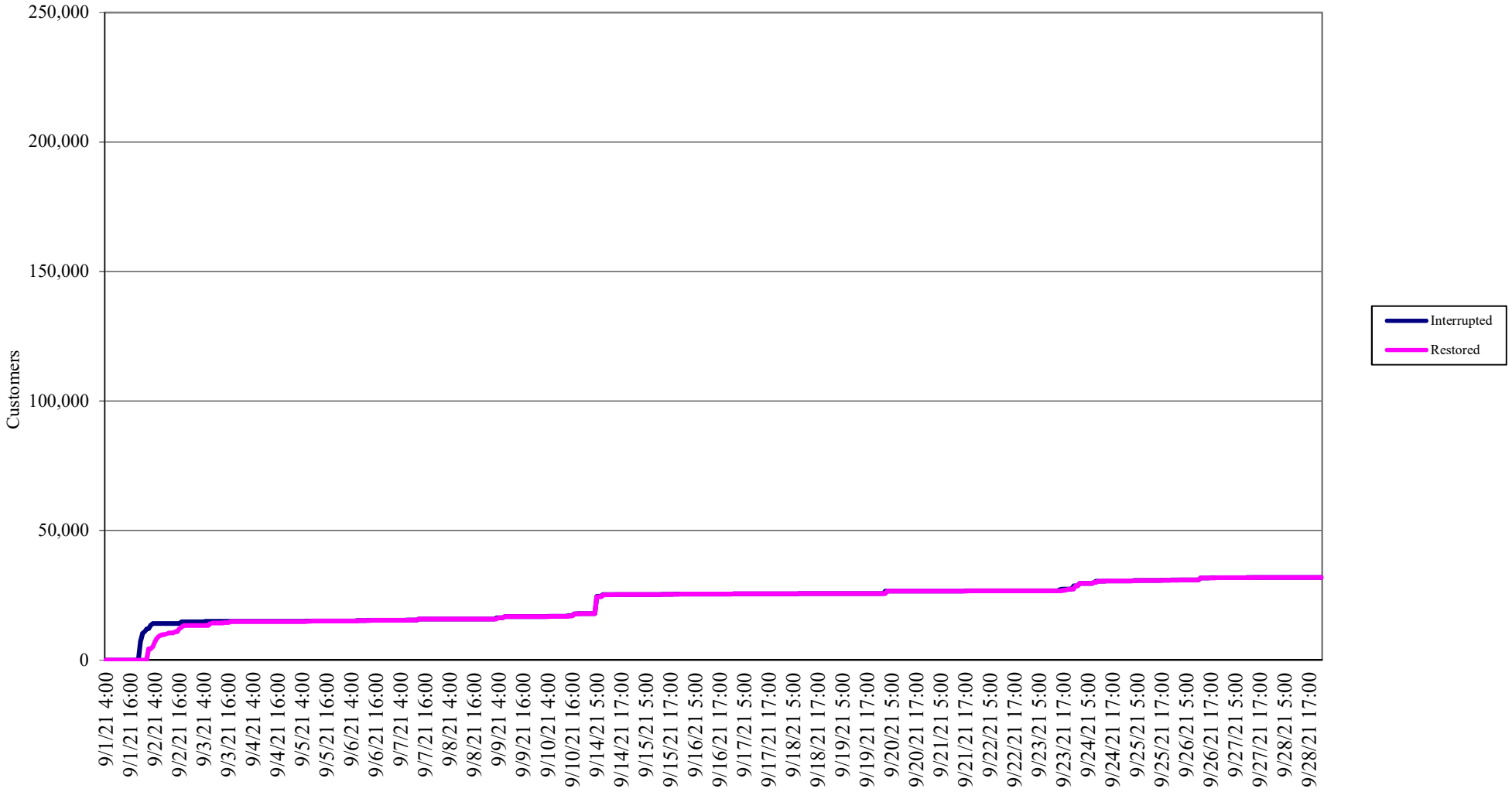
As required in Recommendation 11 from the Tropical Storm Isaias Board Order, a review of past storms revealed that this event was somewhat similar to the remnants of Tropical Storm Lee that affected PSE&G's service territory during the period September 4 - 12, 2021 when 100,022 customers experienced extended interruptions. The resiliency projects completed in PSE&G's Energy Strong I program and those that are currently underway in PSE&G's Energy Strong II program all contribute to improved reliability both during blue sky days and during Major Events. Comprehensive, comparison resiliency data involving Major Events is reported quarterly by PSE&G to the Independent Monitor as part of PSE&G's Energy Strong II Program, as it was during the Energy Strong I Program. The data referencing this event during the period September 1 - 28, 2021 will be submitted in PSE&G's Third Quarter 2021 Energy Strong II Program Report.

DWW: bmc
10/14/21

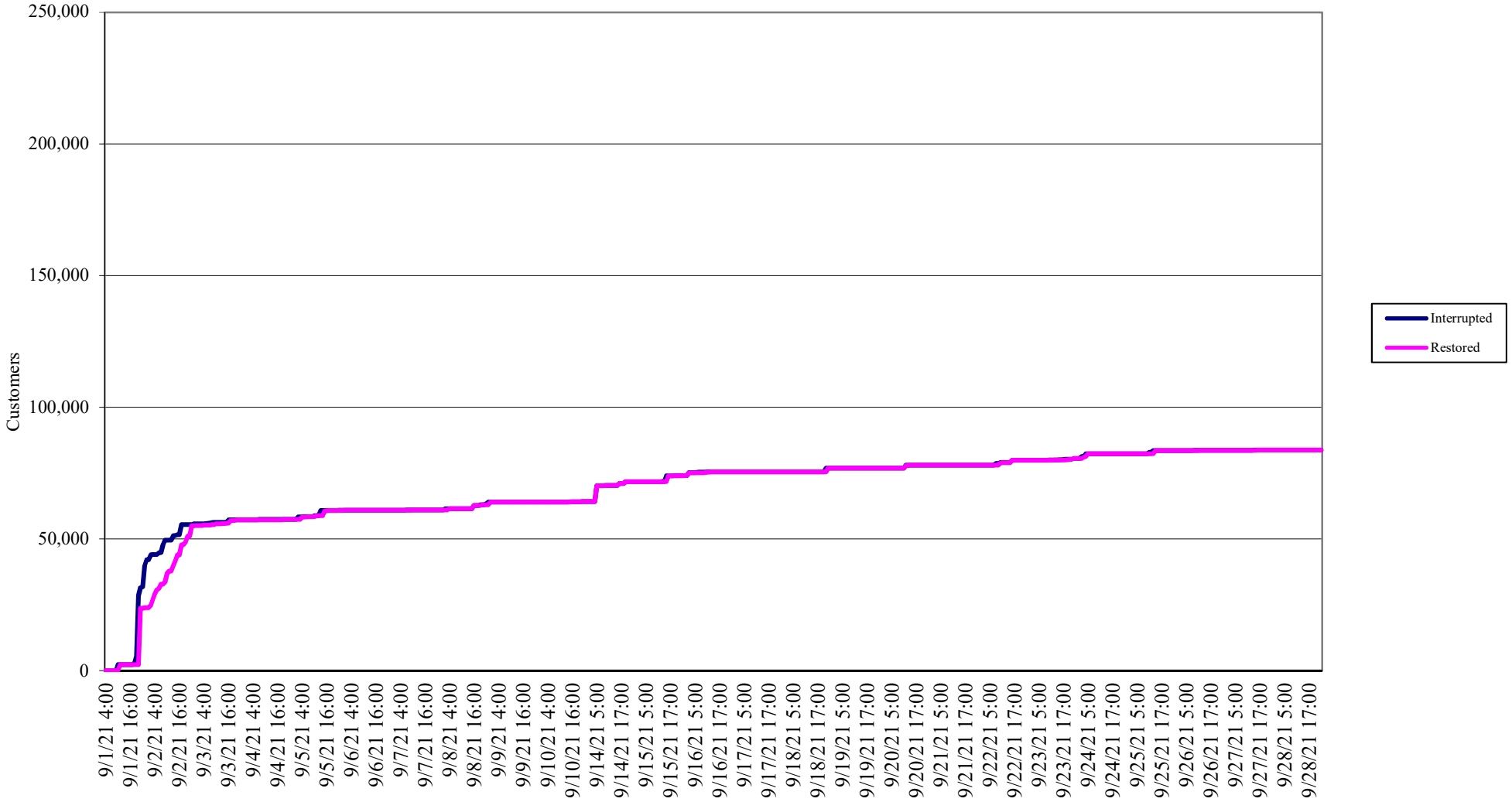
Attachment "A"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Company Wide



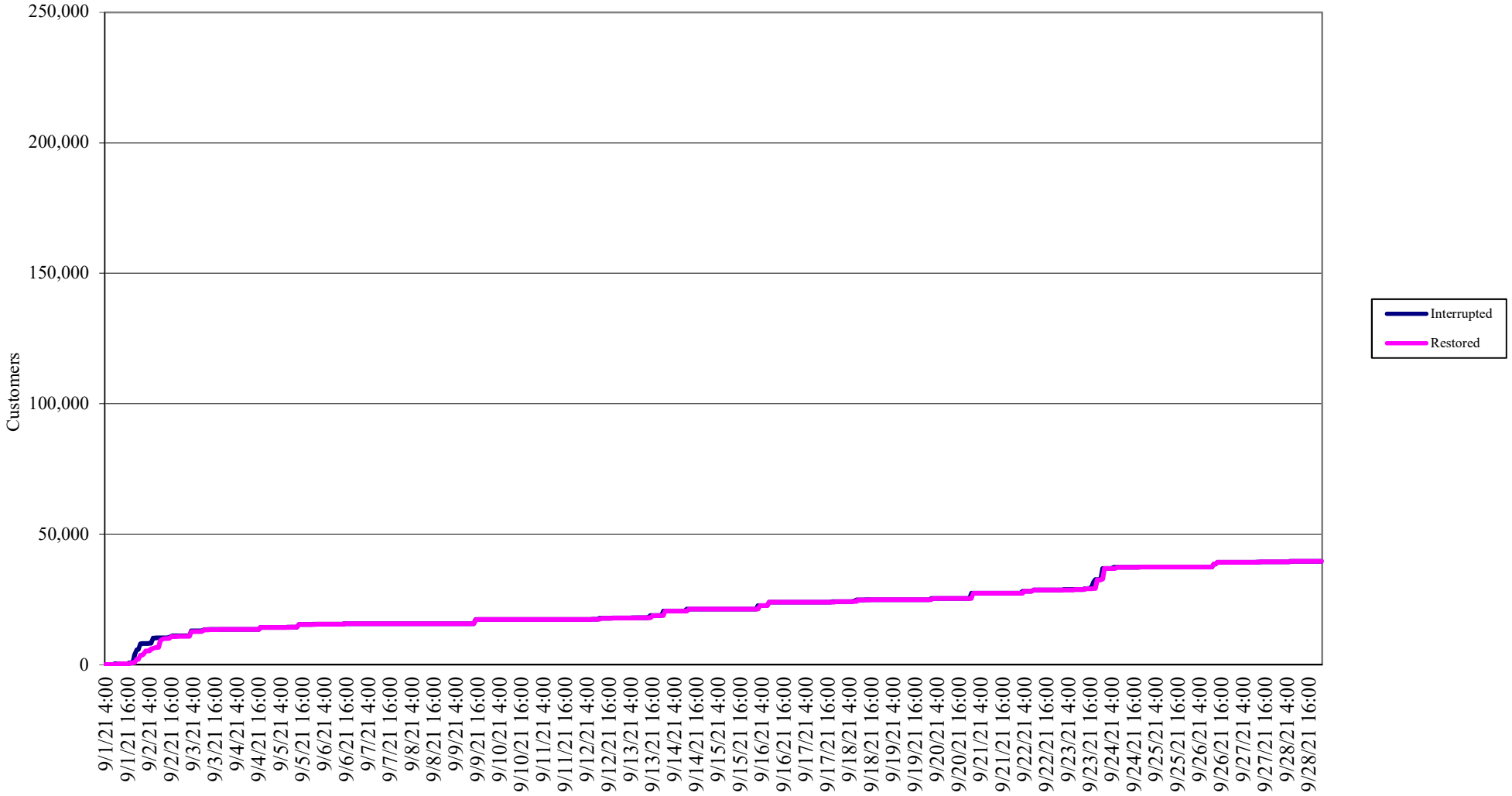
Attachment "B"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Central Division



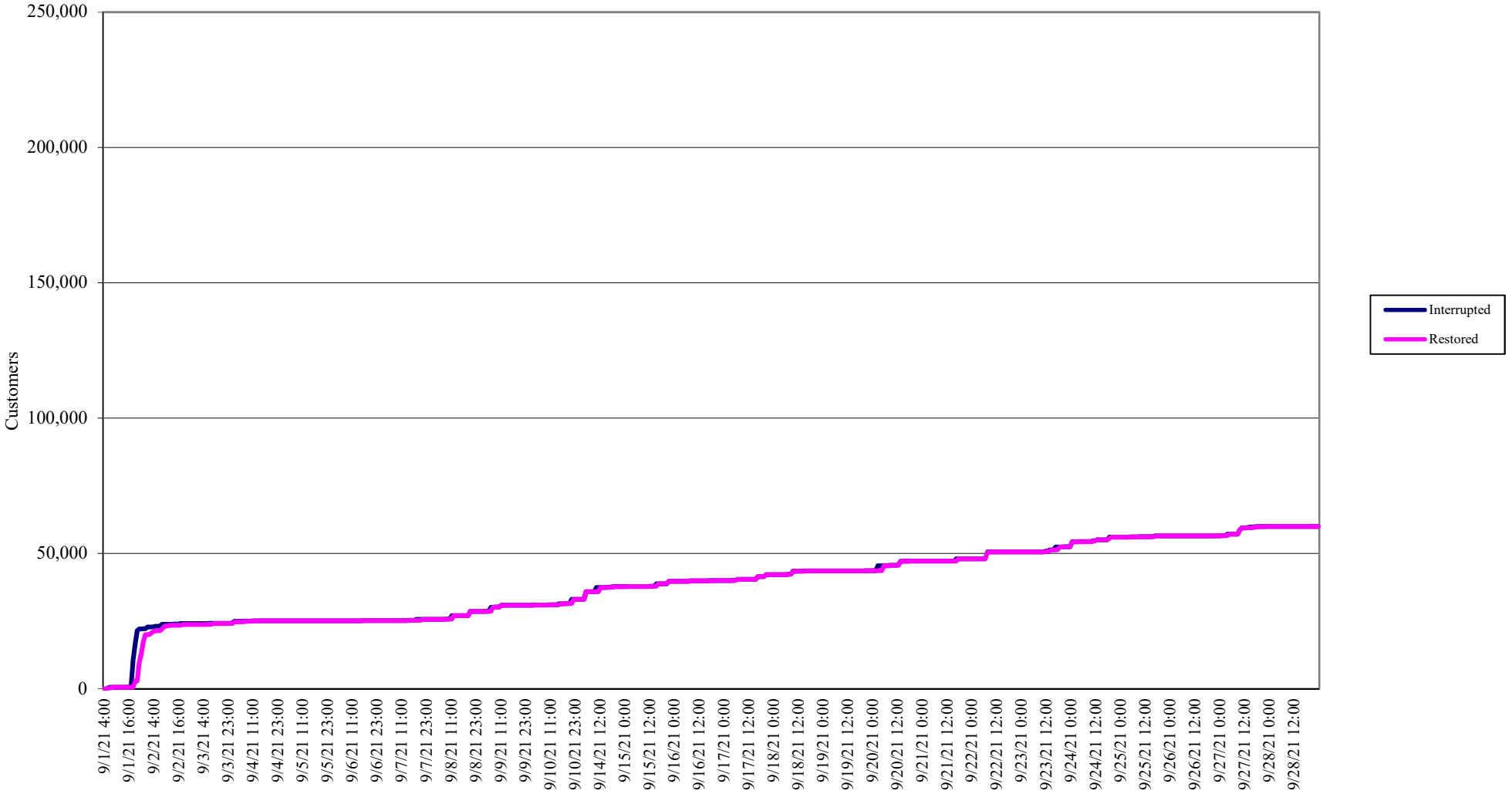
Attachment "C"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Metropolitan Division



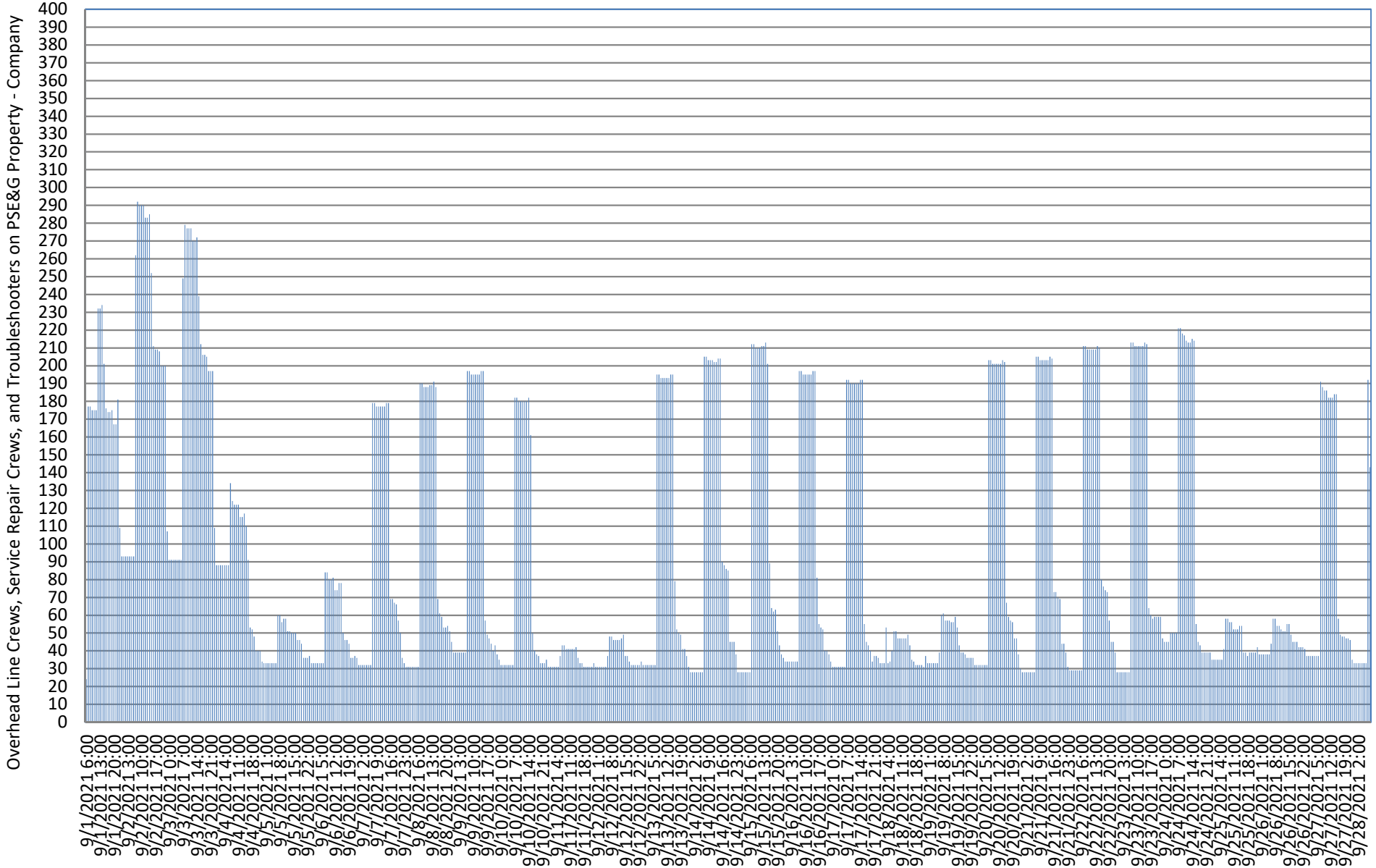
Attachment "D"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Palisades Division



Attachment "E"
PSE&G
Customer Restoration Summary
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
September 1 - September 28, 2021
Southern Division

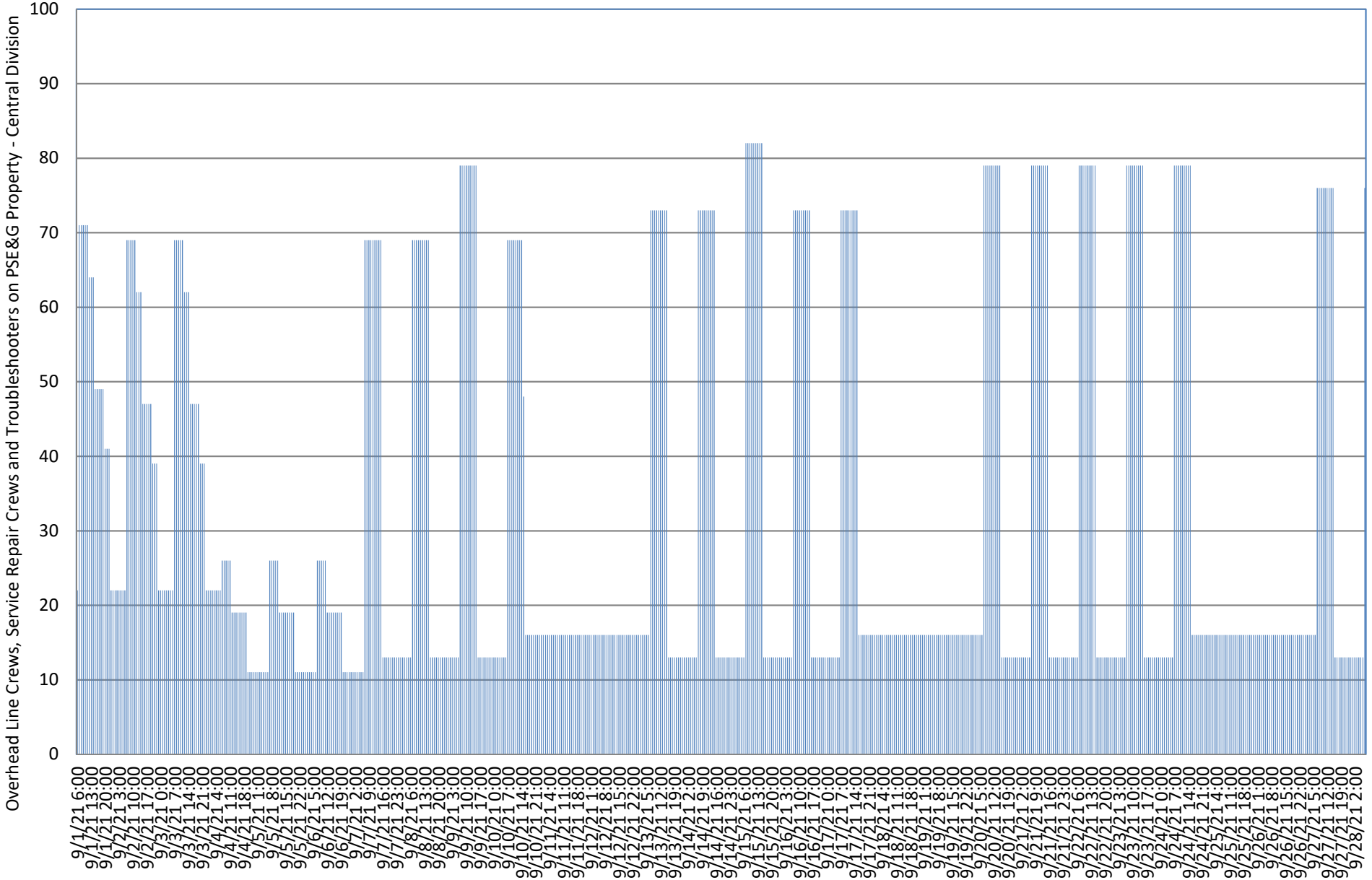


Attachment "F"
PSE&G
Overhead Line Crews, Service Repair Crews, and Troubleshooters on PSE&G Property - Company
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021

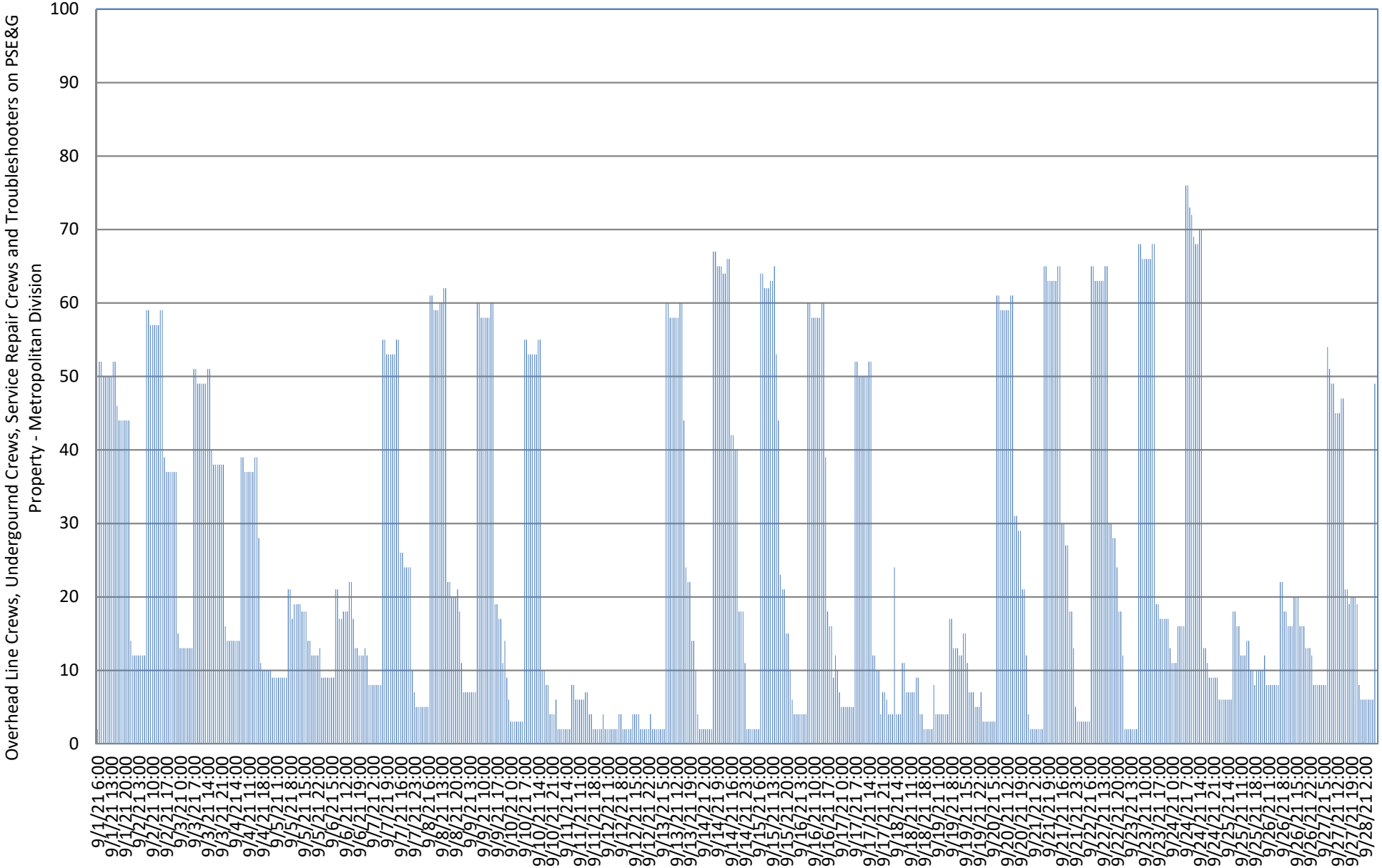


*These values include P&C Workforce Numbers

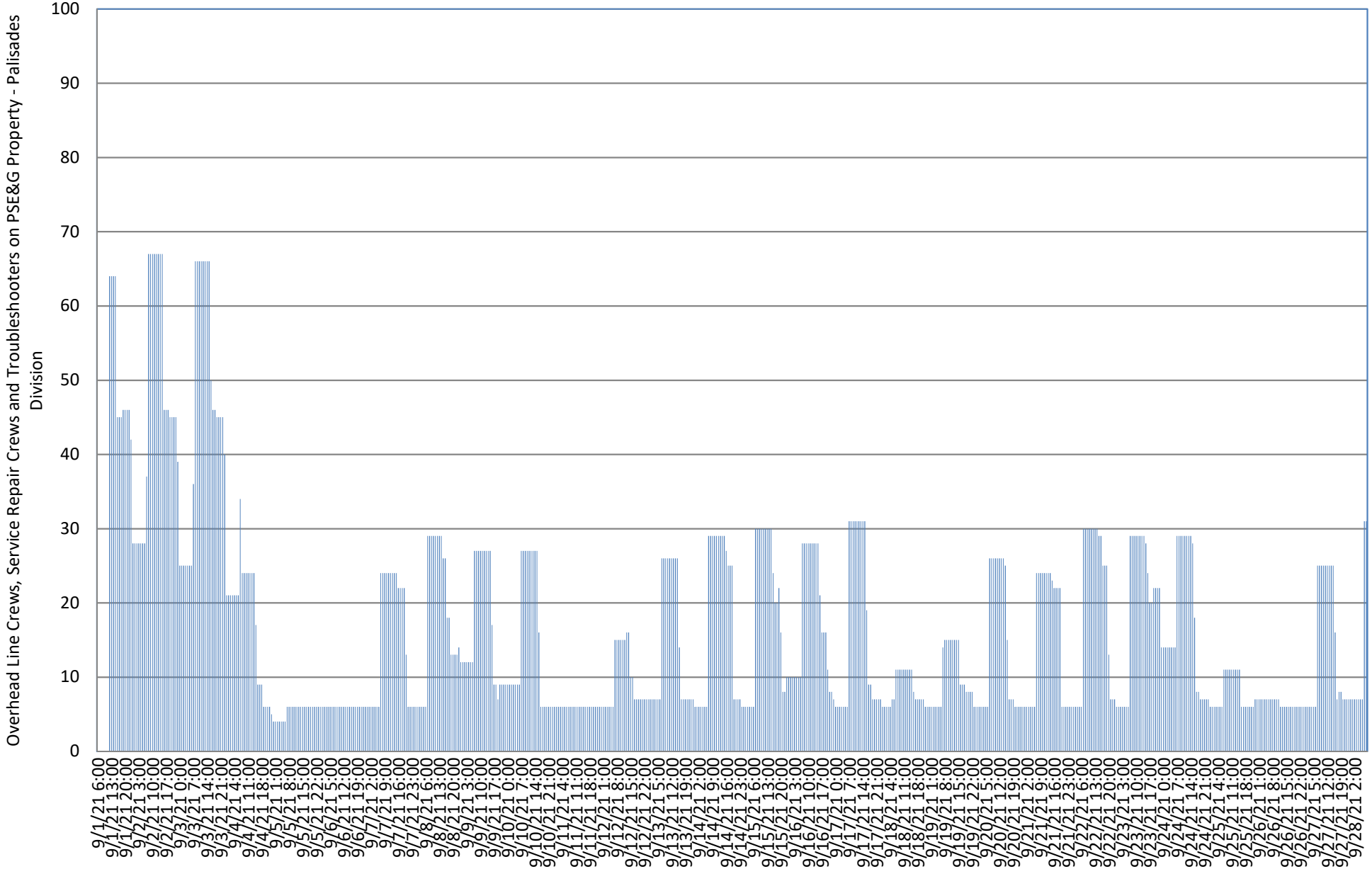
Attachment "G"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Central Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



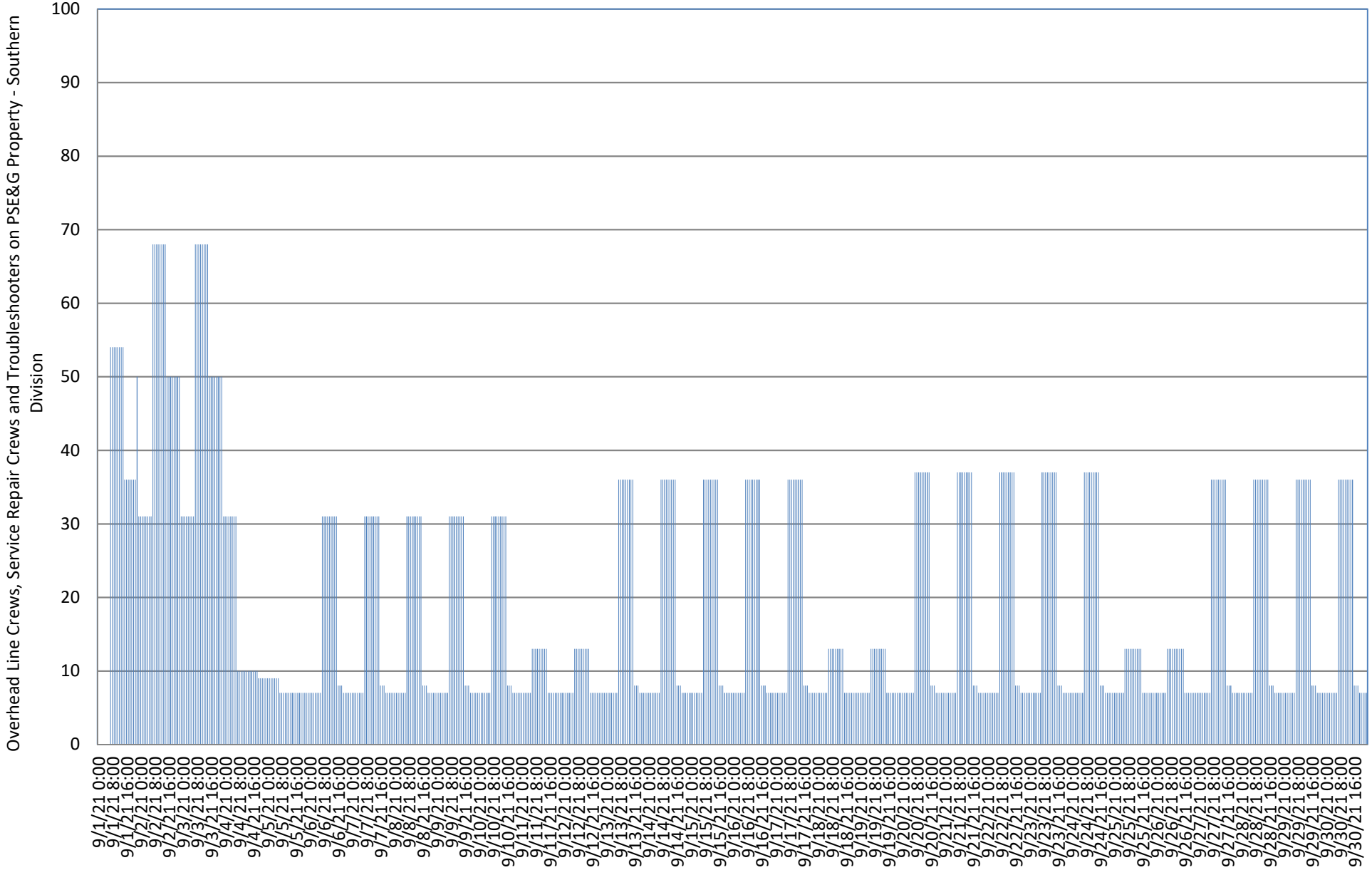
Attachment "H"
PSE&G
Overhead Line Crews, Undeground Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



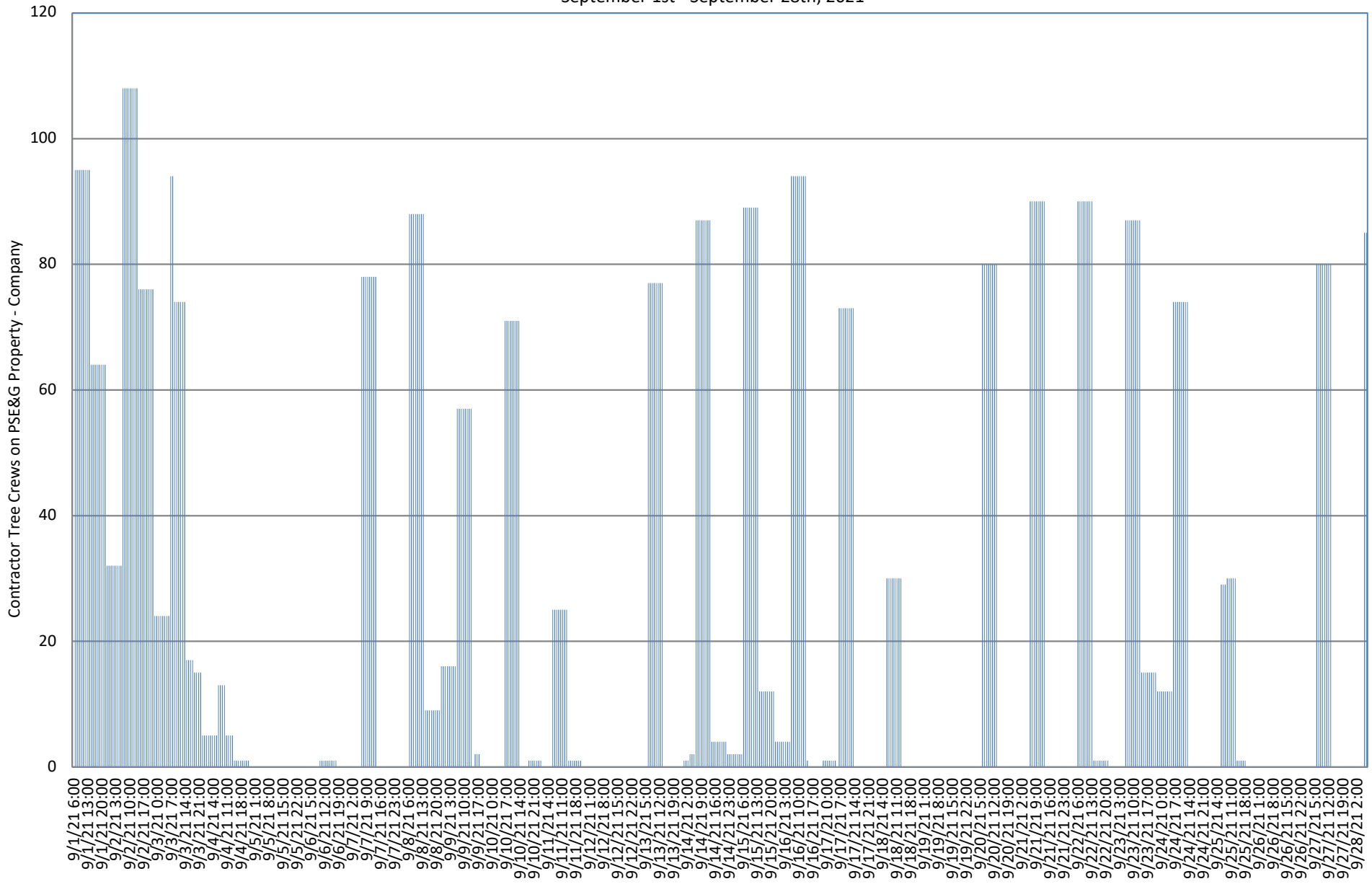
Attachment "I"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Palisades Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



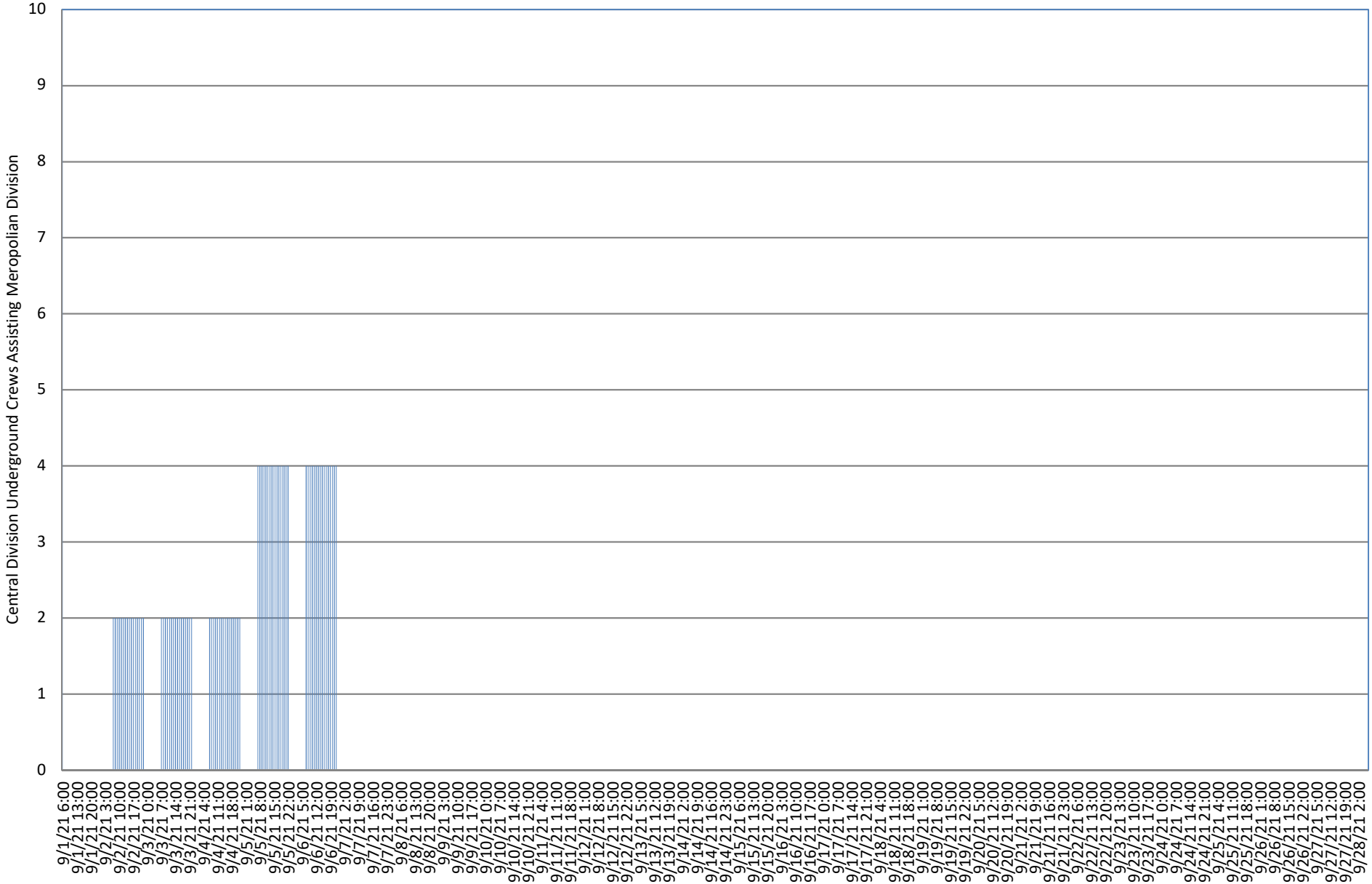
Attachment "J"
PSE&G
Overhead Line Crews, Service Repair Crews and Troubleshooters on PSE&G Property - Southern Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



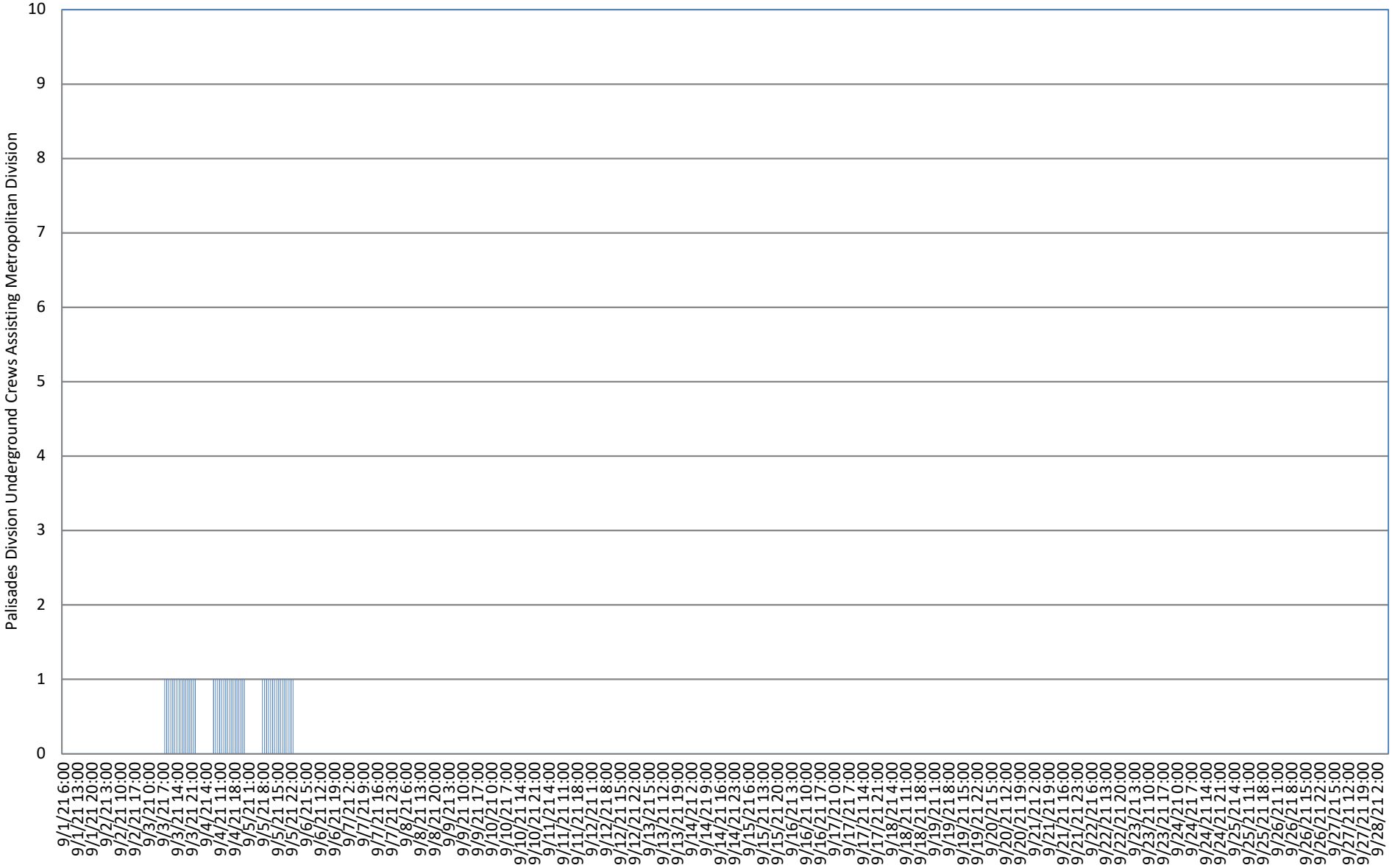
Attachment "K"
PSE&G
Contractor Tree Crews on PSE&G Property - Company
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



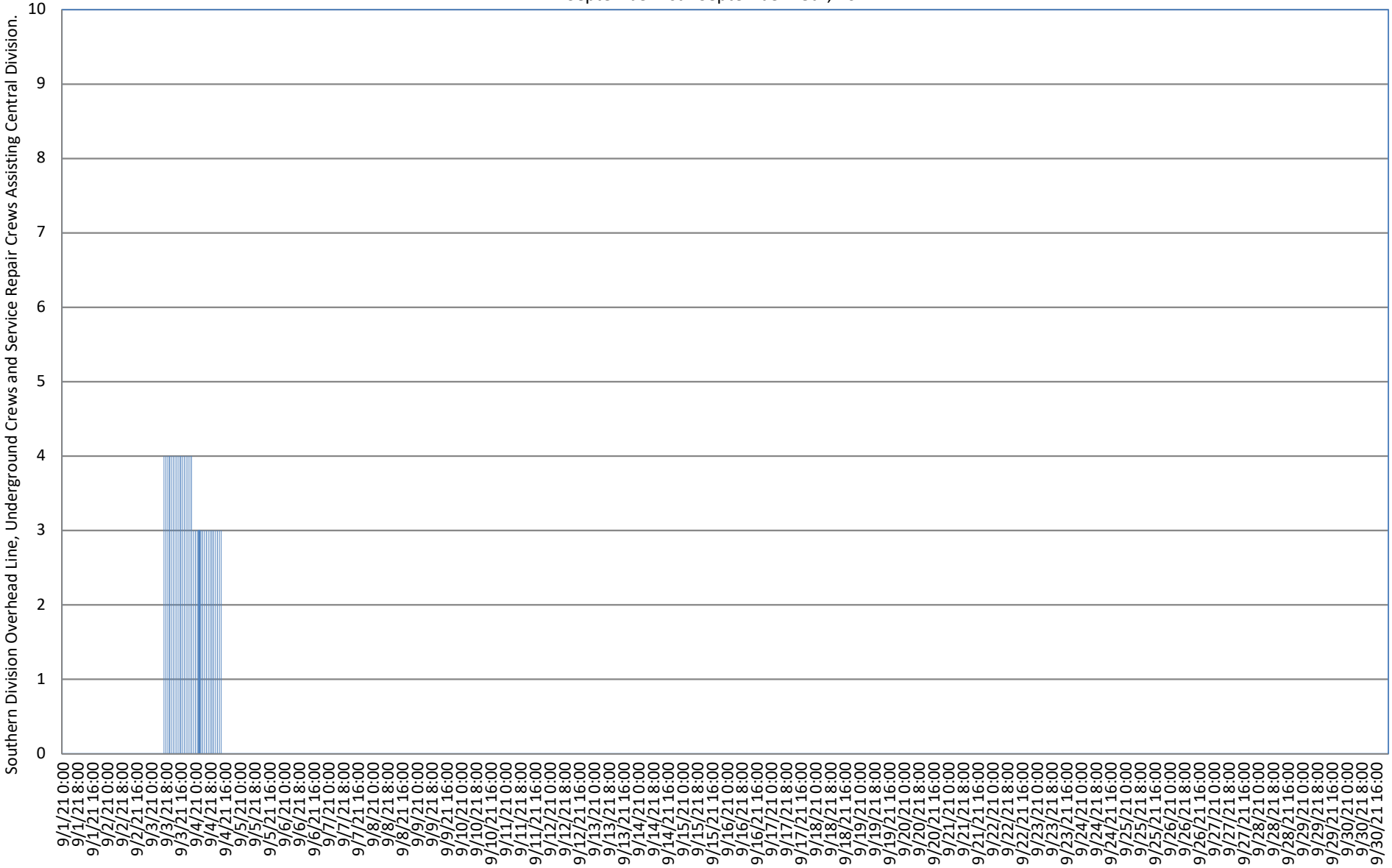
Attachment "L"
PSE&G
Central Division Underground Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



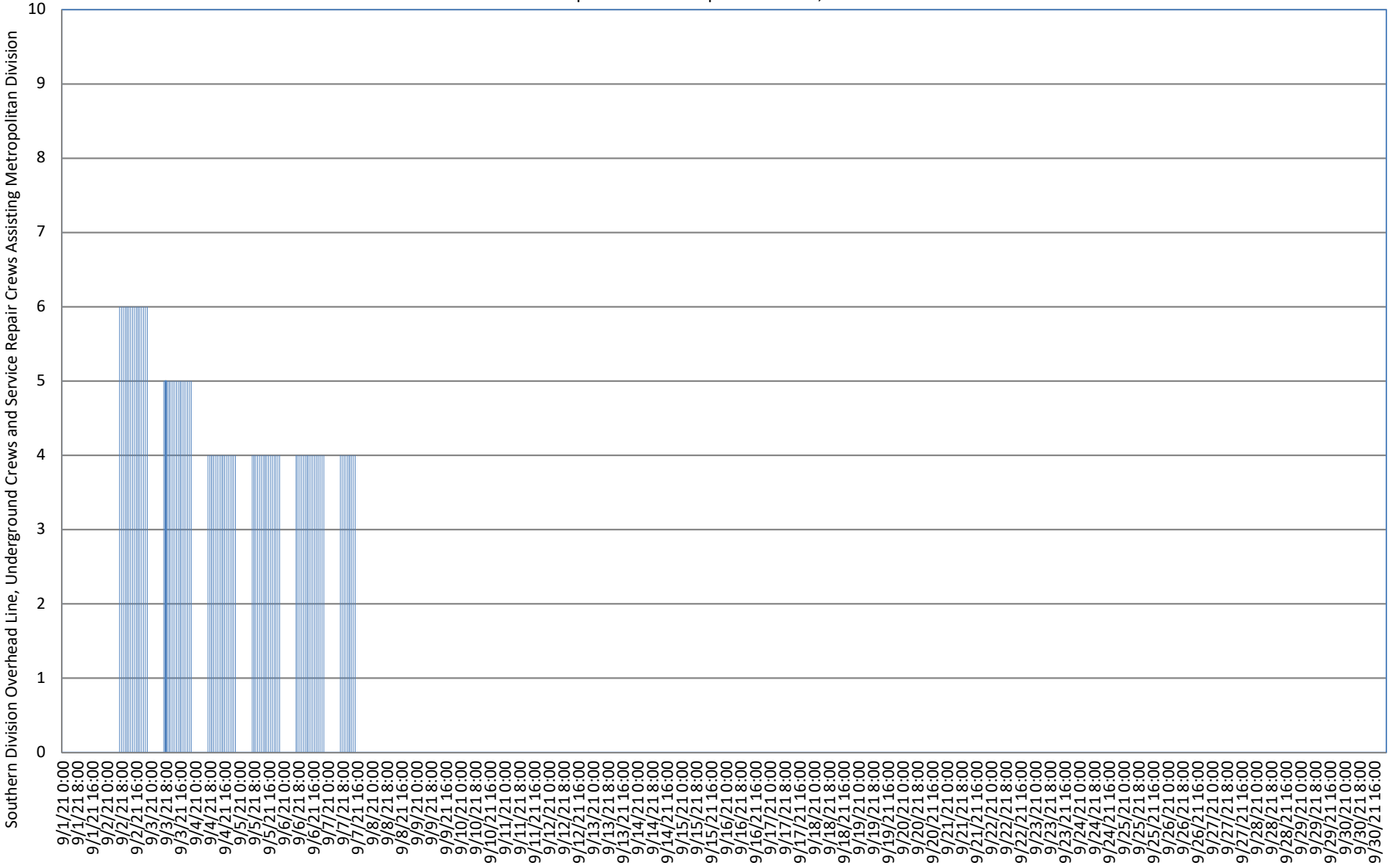
Attachment "M"
PSE&G
Palisades Division Undergound Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



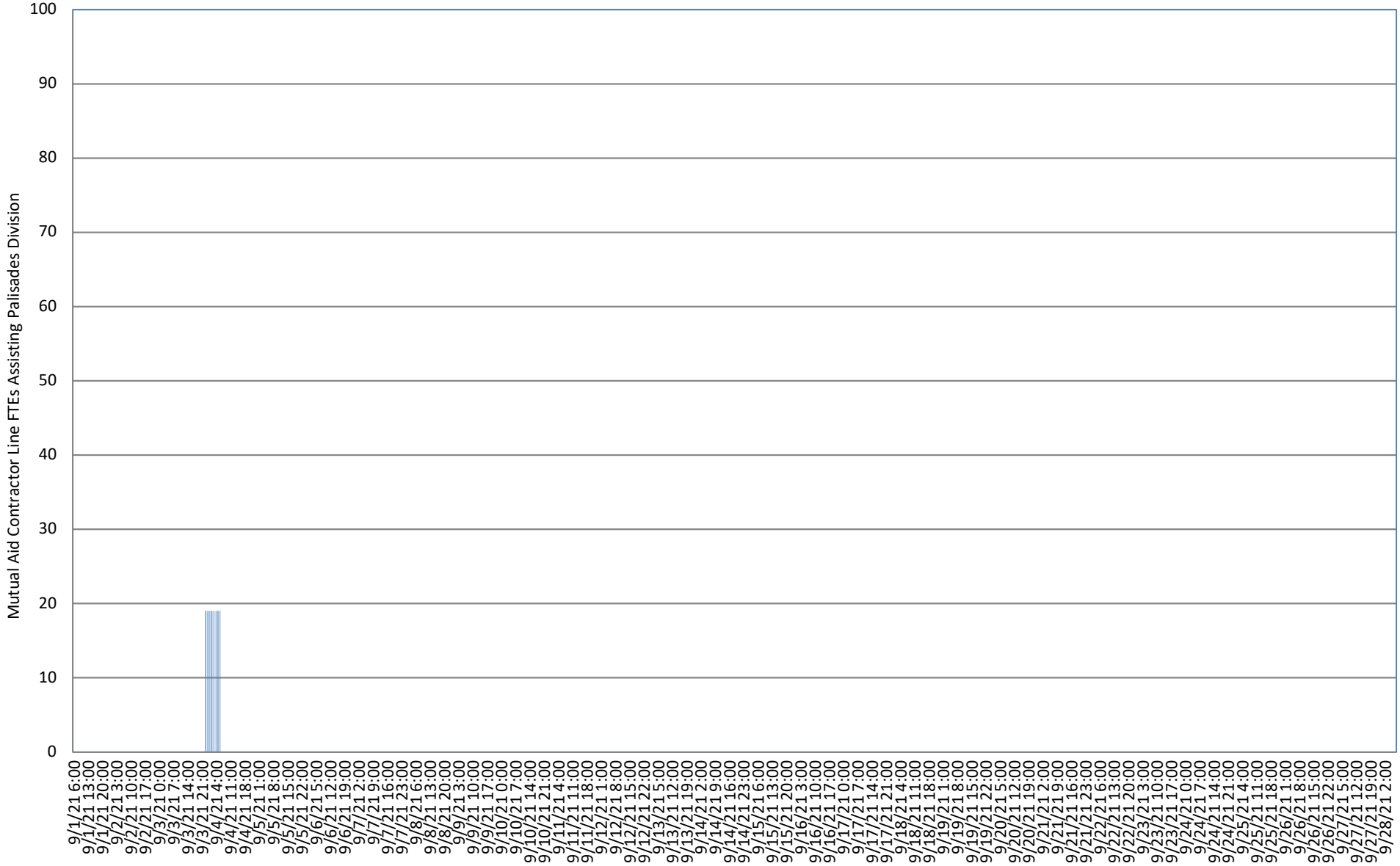
Attachment "N"
PSE&G
Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Central Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



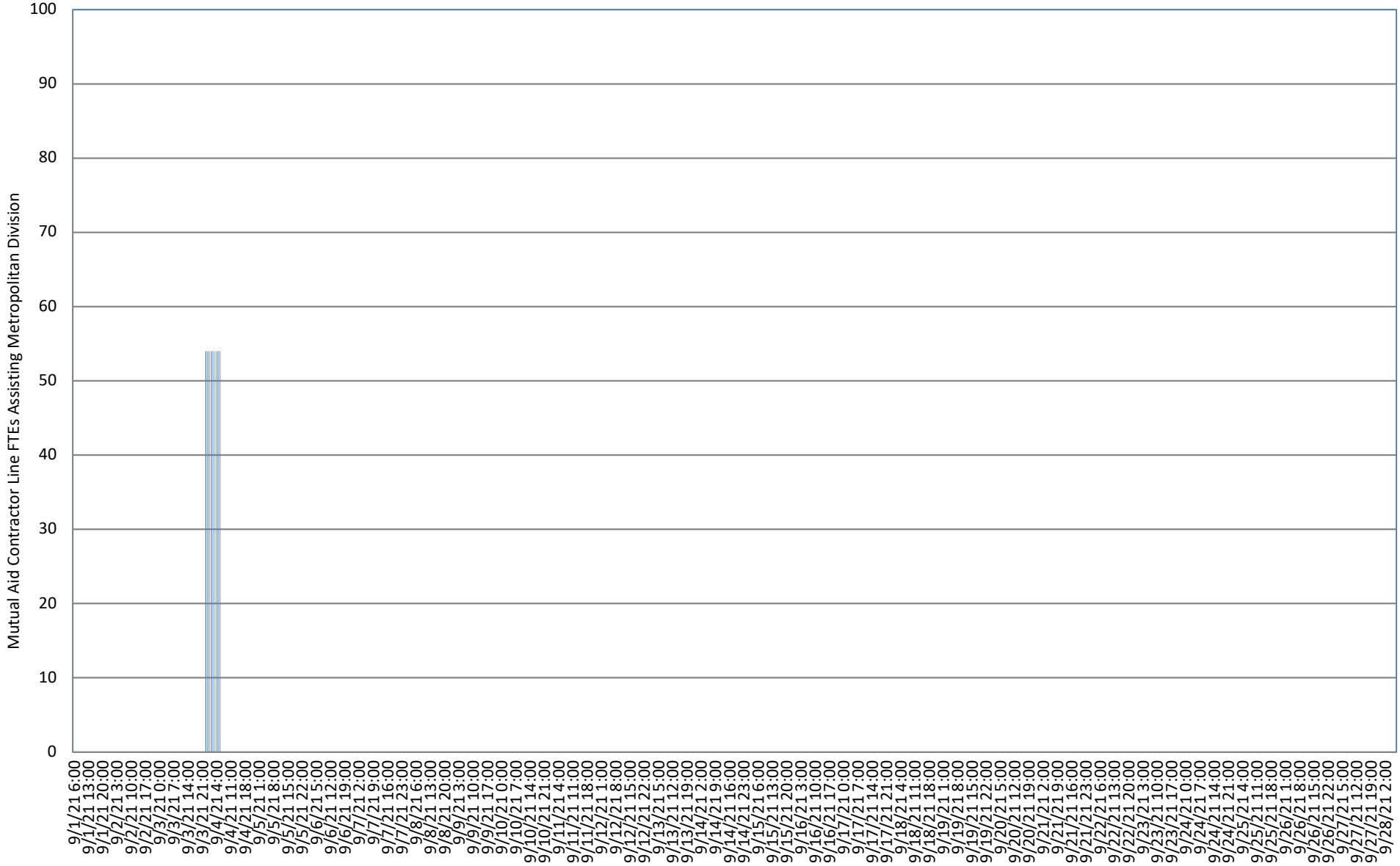
Attachment "O"
PSE&G
Southern Division Overhead Line, Underground Crews and Service Repair Crews Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



Attachment "P"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Palisades Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



Attachment "Q"
PSE&G
Mutual Aid Contractor Line FTEs Assisting Metropolitan Division
State of Emergency - Remnants of Hurricane Ida – Flooding – Load Shedding – East Orange
- September 1st - September 28th, 2021



		9/1 Storm Electric Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	**2,417,158**	**5,659,643**	**8,076,802**	**2,184,546**
2	Contractor/Mutual Aid	131,745	392,804	524,550	392,804
3	Tree Removal	309,308	554,967	864,275	554,967
4	Buses	-	-	-	-
5	Other Contractor	402,373	270,097	672,470	270,097
	Total Contractor	**843,427**	**1,217,868**	**2,061,295**	**1,217,868**
6	Material	**955,181**	**90,895**	**1,046,076**	**86,727**
7	Food	18,126	31,171	49,297	31,171
8	Lodging	7,995	10,631	18,626	10,631
9	Security	-	-	-	-
10	Water and Ice	-	201,293	201,293	201,293
14	Email Alerts	-	8,572	8,572	8,572
11	Other	96,317	148,100	244,417	18,502
	Total Other	**122,438**	**399,767**	**522,205**	**270,170**
	Total Incurred	**4,338,204**	**7,368,174**	**11,706,378**	**3,759,310**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	**4,338,204**	**7,368,174**	**11,706,378**	**3,759,310**

		9/1 Storm Gas Delivery Capital Expenditures (CapEx)	O&M Expenses	CapEx + O&M Expenses	Incremental O&M Expenses
1	Total Labor	-	**6,875,087**	**6,875,087**	**3,089,713**
2	Contractor/Mutual Aid	-	-	-	-
3	Tree Removal	-	-	-	-
4	Buses	-	-	-	-
5	Other Contractor	-	396,316	396,316	396,316
	Total Contractor		**396,316**	**396,316**	**396,316**
				-	
6	Material	-	**60,349**	**60,349**	**49,022**
				-	
7	Food	-	-	-	-
8	Lodging	-	-	-	-
9	Security	-	-	-	-
10	Water and Ice	-	-	-	-
14	Email Alerts	-	-	-	-
11	Other	-	337,531	337,531	210,130
	Total Other		**337,531**	**337,531**	**210,130**
				-	
	Total Incurred		**7,669,282**	**7,669,282**	**3,745,180**
12	O&M Base Rate Storm Costs	-	-	-	-
	Total	-	**7,669,282**	**7,669,282**	**3,745,180**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
CORRECTED 2020 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Background 3
B. Key Decisions 5
C. Program Management 9
D. Cost Assignments 13
E. System Performance 18
III. Project Status 19
A. Electric Station Flood Mitigation 19
B. Contingency Reconfiguration 36
C. Grid Modernization – Communication System 38
D. Grid Modernization – ADMS 40
E. Electric Stipulated Base 41
F. Gas M&R Station Upgrades 41

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS

Advanced Metering Infrastructure ..... AMI

Allowance for Funds Used During Construction ..... AFUDC

Architectural and Engineering ..... A/E

Board of Public Utilities ..... BPU

Construction Management Association of America ..... CMAA

Construction Work In Progress ..... CWIP

Costs of Removal ..... COR

Distribution Management System ..... DMS

Distributed Energy Resource Management System ..... DERMS

Energy Strong 2 ..... ES 2

Environmental Protection Agency ..... EPA

Federal Emergency Management Agency ..... FEMA

Federal Energy Regulatory Commission ..... FERC

Gas Metering & Regulating ..... Gas M&R

Generally Accepted Accounting Principles ..... GAAP

Geographic Information System ..... GIS

Hazardous Water Operations and Emergency Response ..... HAZWOPER

Independent Monitor ..... IM

New Jersey Department of Environmental Projection ..... NJDEP

Open Systems International Inc. ..... OSII

Operations & Maintenance ..... O&M

Outage Management System ..... OMS

Project Execution Plan ..... PEP

Project Management Body of Knowledge ..... PMBOK

Project Management Institute ..... PMI

Project Management Office ..... PMO

Projects & Construction ..... P&C

Public Service Electric & Gas ..... PSE&G

Request for Proposals .....RFP

Record of Decision ..... ROD

Risk and Contingency ..... R&C

Supervisory Control and Data Acquisition..... SCADA

System Average Interruption Duration Index ..... SAIDI

Utility Review Board ..... URB

I. Executive Summary

The Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station lifecycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

Upon approval of the Stipulation, various planning efforts were initiated on the ES 2 Program through the end of 2019 and the first part of 2020. The planning led to certain projects moving forward into execution (primarily the recloser installations within the Contingency Reconfiguration subprogram and outside plant construction on two of the Electric Station Flood Mitigation projects). **Table 1 – ES 2 Subprogram Status as of March 31, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram Status as of March 31, 2020

Subprogram	Q4 2019 Spend	Q1 2020 Spend	Total Spend*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**
Electric Station Flood Mitigation	**$1,977,398**	**$5,118,886**	**$7,096,284**	**$309,160,283**	**2%**	**Dec 2023**
Contingency Reconfiguration	**$9,600,174**	**$14,933,431**	**$24,533,604**	**$119,496,564**	**21%**	**Aug 2023**
Grid Modernization – Communications	**$83,766**	**$2,214,312**	**$2,298,078**	**$65,079,990**	**4%**	**Dec 2023**
Grid Modernization – ADMS	**$36,213**	**$925,689**	**$961,902**	**$40,375,128**	**2%**	**Dec 2023**
Electric Stipulated Base	**$0**	**$0**	**$0**	**Under Development**	**N/A**	**Under Development**
Gas M&R Station Upgrades^	**$52,406**	**$235,922**	**$288,328**	**$65,621,877**	**0%**	**Jul 2023**
Total*	**$11,749,957**	**$23,428,239**	**$35,178,195**	**$599,733,842**	**6%**	**Dec 2023**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 9 and **Table 15** for the Electric Station Flood Mitigation and Gas M&R project estimates with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

As shown in **Table 1**, the Electric Stipulated Base component remains in a planning stage as of the end of the first quarter of 2020, with approval on the initial projects expected to occur during the second quarter of 2020.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Program Electric Station Flood Mitigation Status as of March 31, 2020**.

Table 2 – ES 2 Program Electric Station Flood Mitigation Status as of March 31, 2020

Project	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service Date
1. Academy Street	$17,000,000	$250,291	1%	10/25/2021
2. Clay Street	$42,000,000	$336,116	1%	1/26/2023
3. Constable Hook	$5,300,000	$69,647	1%	TBD
4. Hasbrouck Heights	$18,000,000	$343,727	2%	11/18/2022
5. Kingsland	$10,000,000	$212,398	2%	10/4/2023
6. Lakeside Avenue	$36,100,000	$321,167	1%	9/20/2023
7. Leonia	$32,200,000	$289,114	1%	12/2/2022
8. Market Street	$30,000,000	$2,189,906	7%	9/22/2021
9. Meadow Road	$9,000,000	$206,074	2%	9/21/2023
10. Orange Valley	$26,600,000	$173,611	1%	TBD
11. Ridgefield 13kV	$25,500,000	$523,271	2%	9/27/2022
12. Ridgefield 4kV	$21,100,000	$836,542	4%	6/30/2021
13. State Street	$28,600,000	$205,878	1%	9/23/2022
14. Toney's Brook	$19,700,000	$327,687	2%	4/11/2023
15. Waverly	$35,400,000	$459,454	1%	12/7/2023
16. Woodlynne	$19,400,000	$351,400	2%	9/25/2023

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects are the only two projects to have actual spend beyond 2% of the total project estimate, which is reflective of these two projects being the only projects that have entered into construction.

While early in the subprogram, the Independent Monitor (IM) has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

The IM has conducted its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). Those standards require that the IM plan and perform the assessment to obtain sufficient, appropriate evidence to provide a reasonable basis for the IM's findings and observations based on the IM's objectives. To date, the IM has been provided access to PSE&G personnel and document records as requested by the IM during the execution of the independent monitoring. The personnel interviewed responded fully to every issue raised and questions asked by the IM. The findings contained within this initial report are based upon the oral interviews and documents provided by PSE&G. The IM finds that the information obtained provides a reasonable basis for the IM's findings and observations.

The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On July 15, 2020, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel, and on August 13, 2020 the draft report was reviewed with the same parties over teleconference. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the

draft report and the IM's response is provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Background

On June 12, 2018, Public Service Electric & Gas (PSE&G) filed a petition in support of the ES 2 Program, which sought to continue the progress made under the original Energy Strong Program as to improving the reliability and resiliency of its electric and gas systems. After a period of discovery, filing of testimony, evidentiary hearings, and settlement conferences, a Stipulation was reached on August 23, 2019 that established the agreed upon parameters of the ES 2 Program, including:

- Established the Energy Strong 2 Accelerated Rate Recovery Mechanism;
- Set the Program to be conducted from October 1, 2019 through December 31, 2023, with PSE&G having the ability to request an extension of the Program beyond this term;
- Defined the five subprograms that comprise the ES 2 Program, including the investment amounts:
    - Electric Station Flood Mitigation – $389 million (and further identified the specific stations included and the anticipated mitigation method for each);
    - Contingency Reconfiguration – $145 million;
    - Grid Modernization, Communication System – $72 million;
    - Grid Modernization, ADMS – $35 million; and
    - Gas M&R Station Upgrades (and further identified the specific stations) – $50.5 million.
- Provided the ability for PSE&G to reallocate funds between electric subprograms:
    - Reallocations of 5% or less of the overall electric investment to be made immediately, with written notice required within 30 days of the change; and
    - Any reallocations over 5% allowing Board Staff and Rate Counsel a 15-day period to object before the change is implemented.
- Provided the ability for PSE&G to change the electric substation mitigation method from what was originally anticipated if the proposed change would reduce costs while achieving the same benefits or if permitting or other circumstances make it impossible or inappropriate to use the originally anticipate mitigation method;
- If the Electric Station Flood Mitigation subprogram is completed under the budgeted $389 million amount, PSE&G may reallocate any remaining funds to stations identified in the filing for life cycle station upgrades for accelerated recovery;
- If the Electric Station Flood Mitigation or Gas M&R subprograms cannot be completed within their respective approved amounts, PSE&G may seek recovery of additional amounts in its next base rate case and any prudently incurred costs beyond the approved amount will be credited towards the baseline capital expenditure requirement (electric) or the stipulated base requirement (gas);
- Established the Stipulated Base, with $100 million to be spent at PSE&G's discretion toward electric outside plant higher design and construction standards and/or electric life cycle subprograms identified in the initial ES 2 filing and $50.5 million to be spent in completing the Gas M&R Station Upgrades specified in the ES 2 Program (and additional stations if the initial six stations are completed within the approved amount);

- Specified the reporting requirements for PSE&G's quarterly reports to Board Staff and Rate Counsel; and
- Required PSE&G retain an independent monitor to review and report on the impact of the ES 2 Program on overall system performance during severe weather events; cost effectiveness and efficiency; appropriate cost assignment; and other information deemed appropriate by PSE&G, Board Staff, and Rate Counsel.

The Stipulation was approved by a September 11, 2019 BPU Order with an effective date of September 21, 2019.

1. Energy Strong 2 Program Accelerated Rate Recovery Mechanism

The ES 2 accelerated recovery roll-in schedule contemplates six rate adjustment periods, beginning with an initial filing on November 1, 2020 and continuing with annual or semi-annual filings through November 1, 2023. PSE&G's planning has structured the ES 2 Program deliverables around these roll-in filings as shown in **Table 3 – ES 2 Program Roll-in Filings**.

Table 3 – ES 2 Program Roll-in Filings

Roll-In Filing (initial filing)	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communication	Grid Modernization - ADMS	Gas M&R Station Upgrades
(1) Nov 2020		X	X		
(2) Nov 2021	X	X	X		X
(3) May 2022	X	X	X	X	X
(4) Nov 2022	X	X	X	X	X
(5) May 2023	X	X	X		X
(6) Nov 2023	X		X		X
Note: Office-Level Schedule					

2. Stipulated Base

The Stipulation included Stipulated Base investments totaling $150.5 million that are to be recovered through PSE&G's next base rate case, provided the investments are found to be prudent. The $150.5 million is split between $100 million for electric outside plant higher design and construction standards and/or electric life cycle subprograms and $50.5 million towards the completion of the Gas M&R station upgrades defined in the Stipulation (effectively meaning half of this subprogram is eligible for recovery through the ES 2 accelerated rate recovery mechanism, and half through PSE&G's next base rate case).

3. The Independent Monitor

As set forth by the Stipulation, PSE&G was mandated to retain an independent monitor to review and report on the progress of the ES 2 Program. The scope of work established by PSE&G for the IM services expanded on the tasks identified in the Stipulation as follows:

1. Review and report on the impact of the ES 2 Program on overall system performance during severe weather events, including:
    a. Whether any station with flood mitigation work completed goes out of service due to water intrusion from flooding or storm surge within the applicable Federal Emergency Management Agency (FEMA) Advisory Base Flood Elevation that the station is designed to withstand;

   b. Storm circuit System Average Interruption Duration Index (SAIDI) savings – customer outages and customer minutes saved due to increased sectionalization; and
   c. System SAIDI savings – customer outages and minutes saved. To the extent there are no observable events to provide data during this construction time period or insufficient construction or completion of investments when such an event occurs, the IM shall analyze and advise on the reasonable anticipated performance of such events of the type the PSE&G system has experienced in the five years preceding the BPU Order effective September 21, 2019. In addition, the IM shall make any recommendations it deems appropriate to improve ES 2 investment performance during severe weather events.
2. Review and report on cost effectiveness and efficiency – such review shall include the contracting, procurement, permitting, oversight, and management of the projects, whether the work is performed and resulting costs are incurred by PSE&G personnel or outside contractors. Such review shall also include consideration of whether any change in electric or gas flood mitigation method or approach was appropriate. In addition, the IM shall make any recommendations it deems appropriate to improve the cost effectiveness and efficiency of the design, implementation, or operation of the ES 2 investments.
3. Review and report on appropriate cost assignment – the IM shall determine whether the costs charged to the ES 2 Program are in fact costs properly attributable to ES 2 distribution investments that are part of the Program as approved by the BPU Order effective September 21, 2019.

Pegasus-Global submitted a proposal to serve as the IM on the ES 2 Program and was awarded the work under a contract executed on January 15, 2020. The commencement of the IM work was slightly delayed due to Covid-19 related impacts that delayed completion of the PSE&G required background checks and other administrative steps. The IM work was officially initiated with a kickoff meeting held with PSE&G on April 13, 2020. Since that time, the IM has submitted and received responses to numerous document requests and has held multiple interviews with ES 2 Program individuals, including each of the subprogram leads.

B. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this initial IM 2020 First Quarter Report are presented below in **Table 4 – ES 2 Program Records of Decisions**.

Table 4 – ES 2 Program Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in this IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in this IM 2020 First Quarter Report)*

1. Electric Station Flood Mitigation – Academy Street & State Street Change in Mitigation Method

On April 16, 2020, PSE&G notified the BPU of a change of mitigation for the Academy Street and State Street substations. For Academy Street the mitigation change was based on lower costs to rate payers, lower construction risk by constructing on a new site and flood risk reduction by moving the station out of the flood zone. The original Academy Street scope required the acquisition of additional property adjacent to the existing substation. PSE&G proposed to eliminate the Academy Street substation, transferring the load to a new Fairmount substation on property acquired under a separate project. The outside plant work required to convert existing Academy Street customers from 4kV to a 13kV supply will be funded under a separately approved base capital project, which will also fund connection to the new Fairmount substation.

In the same notification to BPU, PSE&G also notified the BPU that it would be changing the mitigation method of the State Street substation from a raise and rebuild to a relocation to Cooper Street. The State Street Substation was originally planned to be a raise and rebuild due to its location within the City of Camden flood zone. Since its original application of ES 2, the City of Camden has targeted the existing station for purchase by the City. The City further opposes any expansion of the substation due to its Waterfront Redevelopment Plan. Based on this opposition, PSE&G met with the City of Camden to discuss alternatives to address the need to remove the substation from the flood hazard zone.

Alternatives were investigated within a one-mile radius of the current State Street substation. However, given the Waterfront Redevelopment Plan, no substation development was permitted. Locating further away also presented construction challenges, in particular the boundary crossings with Interstate 676, NJ Light Rail Transit, and Cooper River. These crossings would have necessitated horizontal directional drilling at a cost between $5-10 million and the reality of 12 circuits being routed further away from the load pocket which would decrease reliability.

A site was identified just outside the FEMA Flood Zone and the Waterfront Development Plan with sufficient space for buildout of a new station. The undeveloped parcel will also facilitate customer supply reliability as existing capacity can remain in service without contingency required with new existing 4kV circuits cut over to the new station at Cooper Station.

The original estimate for the State Street project was $28.6 million ($21.2 million base cost plus $7.4 million for R&C); the new estimate with the relocation is $45.1 million ($37.1 million plus $8 million R&C). The reason for the increased cost is because the new location will require extensive underground installation that was not included in the original scope including manholes and associated duct banks. The original estimate for the Academy Street project was $17.0 million ($12.6 million base cost plus $4.4 million R&C); the new estimate is $12.8 million ($9.9 million base cost plus $2.9 million R&C), which includes the costs related to the new 13kV switchgear at the Fairmount site outside of the flood zone and retiring the existing Academy Street site. The reason for the decreased cost is largely due to no longer needing a contingency to support customer supply during construction as originally planned.

On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the changes to the Academy Street and State Street substations without additional information and clarification on the changes. On May 22, 2020, PSE&G responded to Rate Counsel's request with additional information concerning the proposed changes to the Academy Street and State Street projects.

Findings & Observations:

- The changes in mitigation will:
  - Reduce risks during severe events
  - Reduce risk of customer interruptions associated with construction of a temporary facility to maintain supply during the re-build
  - Allow cutoff without disruption
- The IM finds that PSE&G conducted the appropriate due diligence once it was determined that the original plan and scope for the State Street and Academy Street substations was not going to be a viable option.
- The IM finds that while the cost for the revised State Street mitigation is higher than initially planned, PSE&G appropriately selected a location that minimizes the cost and reliability concerns that would have otherwise occurred had the relocation been further away than the approximate one mile radius.

2. Electric Station Flood Mitigation – Engineering Support for Energy Strong Program Projects

On August 22, 2019, PSE&G documented its decision to solicit external Architectural and Engineering (A/E) firms for ES 2 based on firms previously selected during the competitive bid process for the 69kV transmission upgrade project and/or due to work being performed by a particular A/E on a particular substation that is planned in the ES 2 scope of work.

Similar to the decision made in the original Energy Strong Program, PSE&G engaged the A/E firms that had existing 69kV design contracts to bid on the projects that were aligned with the relevant 69kV projects. All stations, including those relevant 69kV stations, were competitively bid as part of the vetting and selection process utilized by PSE&G. PSE&G's decision-making process evaluated the design configuration. Design configuration refers to processes and methods that assure that the latest approved revision of drawings and other design documents are available to those who need them. In addition, and equally important, is that all changes to those design documents are controlled to include the appropriate reviews, references, justifications, and approvals to assure that changes do not result in a design that no longer fulfills the original design requirements. PSE&G believes that in order to achieve this design configuration control, design work for inside the plant (the substation) should be awarded by this single source process to the design firm who are providing or will provide design services previously for that substation and to not go out for competitive bid on substation design work. This approach will add assurance that the design firm will be working from the latest approved drawings, which will further assure the integrity of the design.

In assessing this decision, the IM asked PSE&G whether this single source contracting strategy results in additional costs than it otherwise might in a competitive bid strategy. During the original Energy Strong Program, PSE&G shared with the IM the documents that support its decision for its single source contracting strategy in this area originally dated May 30, 2014, titled "Engineering Support for Energy Strong Program Projects," and updated on January 12, 2015.[1] The documentation identified the electric stations in the original Energy Strong Program and the design firms that will be asked to bid or have already bid. The firms are only awarded the design work provided the pricing in their proposals is consistent with the work scope and their proposals are otherwise acceptable.

[1] As discussed in the IM 2014 Annual Report (original Energy Strong Program), pp. 91-92

In ES 2, PSE&G's reasoning for the single source selection added that in addition to A/E firms that had or are currently working on a particular substation, that in its decision to meet or exceed PJM requirements in upgrading and improving the overall capacity and rehabilitation of its transmission lines, PSE&G is embarking on an upgrade to a portion of its existing 26kV line to 69kV to provide greater system reliability. As part of the transmission upgrade project, PSE&G issued Request for Proposals (RFP) to various A/E firms and based on a competitively bid process, selected a pool of three A/E firms to award the work. Based on this selection, PSE&G made the determination through its decision-making process to allow the same A/E firms that were selected through this competitive bid process to be awarded work on a specific substation. In addition, PSE&G retained the first right of refusal to complete engineering for some projects in-house versus awarding to an outside A/E firm based on the capabilities and resources available internally. PSE&G made the decision to perform engineering in-house for the following substation projects:

- Ridgefield 4kV
- Ridgefield 13kV
- Market Street
- State Street
- Meadow Road
- Kingsland
- Leonia

For all other work where an A/E is not performing work on a substation for the 69kV transmission project, PSE&G will choose the A/E firm from the top-rated vendors based on the bids received.

Three reasons are cited as to why this contracting strategy is critical to the success of the ES 2 Program:

1. These design firms have worked previously with PSE&G at other electric substations, thus developing a strong relationship with and knowledge of the PSE&G personnel and processes. These firms have the technical experience to do this work that will result in less operational and execution risks. These firms know the PSE&G engineering and construction standards, the outage planning process, and are knowledgeable of the PSE&G system and outage sequencing processes.
2. PSE&G's project execution practice is that multiple design firms cannot be working on the same station drawings at the same time, to avoid coordination issues and decrease the likelihood of commissioning, testing, and energization errors. Using design firms that are currently or will work at specific substations decreases the number of drawing conflicts (design configuration).
3. The engineering/design work traditionally accounts for a very small portion of a project's total cost, approximately 5%. Construction Management work is typically 2-3%. The majority of the cost (>90%) for projects of this nature is in the procurement of materials and the actual construction costs, which will both be competitively bid.

The August 22, 2019 documentation includes additional information that clarifies points that are relevant to PSE&G's single source contracting strategy for design work. The first is that PSE&G already has the competitively bid time and material rates for the design firms in the original 69kV portfolio, in addition to lump sum pricing on certain station options. Those rates will be compared to the rates these same three design firms include in their bid responses to the work inside the plant under the ES 2 Program to ensure no significant variances in the competitively bid rates. The second point is that PSE&G will perform an analysis of the differences between the competitively bid rates and the lump sum rates submitted for the ES 2 Program. This second point is an important commitment in that for every bid to perform design

work inside a substation under the ES 2 Program there will be an evaluation to ensure the costs are reasonable and support the overall execution of the Program.

Findings and Observations:

- The justification to award the engineering/design on specific Electric Station Flood Mitigation subprogram projects on a single source basis is appropriate and supports the overall cost objectives of the subprogram. The cost effectiveness of this decision is supported by the pricing analysis undertaken by PSE&G on the proposals received, including comparing against bids received in the 69kV portfolio.

C. Program Management

1. Program Governance & Oversight

PSE&G established an organizational structure for the ES 2 Program that is similar to the model utilized for the original Energy Strong Program. The ES 2 Program's overall direction and oversight is managed by several key personnel, including:

- Danny Nembhard – ES 2 Electric & Gas Program Manager;
- Ed Gray – Director Electric Transmission & Distribution Engineering (electric program sponsor);
- Wade Miller – Director Gas Transmission and Distribution Engineering (gas program sponsor);
- Damon LoBoi – Senior Director, PSE&G Smart Operations Technology; and,
- Gino Leonardis – Project Director.

The program organization includes functional support from contract administration/procurement, the project management office (PMO), and legal/regulatory. The subprograms within ES 2 have been assigned leads, who are the technical leads for that subprogram and responsible for all aspects of their assigned subprogram, including engineering/design, procurement, construction, commissioning, and turnover to operations. The Leads for the ES 2 subprograms are as follows:

- Electric Substation Flood Mitigation/Lifecycle Upgrades – Christina Ker;
- Contingency Reconfiguration – Donald Gordon;
- Grid Modernization – Communication and ADMS – Al Balletto; and,
- Gas M&R – Charlie Miracola.

Additional discussion on the individual subprograms' organizations is provided within **Section III** for each of the subprograms.

In addition to the above subprogram leads, Nicole Severt is the PMO Manager and provides support for the entire ES 2 Program Electric Program. Sonia Zacher-Martini provides similar PMO support for the ES 2 Gas. Ayo Fapohunda is the PMO Project Control Manager responsible for program reporting. The PMO provides support to the ES 2 Program in a variety of ways including:

- Managing, supporting, and compiling internal and external program status reports;
- Developing monthly cost and schedule project forecasts;
- Preparing interim reporting and variance explanations;
- Managing all schedule and financial tasks (e.g. schedule updates, purchase orders, invoices, accrual management, etc.); and,
- Monitoring and controlling installation completion records, work orders, in-service dates, etc.

Findings & Observations:

- PSE&G has established an effective organization to lead the implementation of the ES 2 Program that includes well-qualified and experienced individuals. The Program is also supported by a PMO and other functional groups (e.g. licensing and permitting, legal, procurement, etc.) to facilitate successful execution.

2. Projects & Construction

The Projects & Construction (P&C) group is responsible for executing large capital projects within PSE&G, which for the purposes of ES 2 includes the projects under the Electric Station Flood Mitigation and Gas M&R subprograms.

Two primary references manuals utilized by the P&C group are *RM-01 Project Controls Engineering* and *RM-02 Project Controls Scheduling*. These reference manuals provide the framework and methodology by which P&C projects are supported by Project Controls Engineers/Project Controls Schedulers, from project initiation through closeout. Each of these references manuals is exceptionally detailed, walking through the required project components for each of the project phases, establishing the applicable methodologies to be used, and providing instruction on how to apply such practices and methodologies within PSE&G's internal systems.

The P&C group also relies on a set of Project Management Procedures to provide the necessary guidance and requirements in elements of project management such as scope management, cost estimating, risk management, and status reporting, among others. The procedures are intended to be adaptable for projects of different sizes and complexity and as such, has different thresholds for projects; for example, the projects under $5 million do not require a full Project Execution Plan (PEP), but instead utilizing a project execution strategy summary that contains information pertaining to scope, schedule, estimate, and other relevant information. A review of this set of procedures is provided as follows, with more detailed examples of the individual functional areas provided in the detailed project discussions under **Section III.A.**, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed.

PMP-01 – Project Execution Plan: Establishes the guidelines for developing a PEP for new projects and conducting periodic reviews of the Project Team's execution strategy. The PEPs developed for new projects consist of three primary parts: project charter; scope management and control plan; and project management plans. Each of those primary parts may contain several component sections, for example, the project management plans include a project estimating plan, project scheduling plan, project risk management plan, and other functional plans to support the execution of the project.

PMP-02 – Scope Management [Hasbrouck]: Establishes the guidelines for scope development, using a phased approach for electric projects, from feasibility, to turnover, to study, with each stage leading to a more refined scope. The gas projects scope development is initiated from the high-level requirements from a request for estimate, which leads to the development of a detailed scope. With agreement from the Project Team and key stakeholders, the scope document is locked as the final approved scope for the project. During execution of a project if scope changes are identified, a project scope change request (if no additional funding beyond the currently approved budget is required) or a capital project change request and capital funding change form (if additional funding is required) is completed and reviewed for approval by the Project Manager, Director – Projects, and other key stakeholders as warranted.

PMP-03 – Project Estimating [Market St.]: Establishes the process for developing and reviewing estimates, with specific applicability to capital projects in excess of $5 million or any blanket project under $5 million for which an estimate has been requested. The estimating process used a phased approach, beginning at the feasibility/turnover, or "office" stage (representing a confidence level of 15%-40%) and continuing through the study stage (50% confidence level), conceptual stage (70% confidence level), and ultimately the definitive stage (90% confidence level). In developing an estimate, estimate checklists are followed to ensure completeness and uniformity. When completed, the estimate is subject to review and challenge sessions and once specified criteria are met, a target budget is established that is utilized as a measure of the project's success.

PMP-04 – Project Scheduling [Kingsland]: Establishes the methodologies for developing, reviewing, and approving project schedules for capital projects. It is applicable to capital projects over $1 million in cost and blanket projects under $1 million that may require schedules upon specific requests at designated levels. Industry standard schedule fundamentals such as ensuring the schedule is inclusive of all work and consistent with the work breakdown structure, that it is developed with consideration of available and required resources and internal or external constraints, and that it is maintained throughout the project to measure performance are listed for adherence in developing schedules. As with the other project management functions, project scheduling occurs in a phased approach that increases with detail as the project moves from initiation through approval.

PMP-05 – Project Authorization [Academy]: Establishes the process for obtaining project funding authorization, change requests, and financial project closeouts on capital and blanket projects managed by P&C. It walks through the different project development phases, from approval for preliminary engineering funding, through authorization and phased funding (if applicable), through managing change requests, and ultimately project closeout. The requirements at these different phases are largely dependent on the deliverables created through other project management procedures (e.g. cost estimate, schedule, etc.).

PMP-06 – Invoice Management [Ridgefield 13kV]: Establishes the process for reviewing and approving vendor or contractor invoices on capital and operations & maintenance (O&M) projects. It provides a review of typical invoice contents and notes the delegation of authority levels of approvals by dollar value, including the responsibilities tasked to those with approval authority. It also provides a responsibilities guideline that details by project function (e.g. contracting, licensing, and permitting, engineering, etc.) how invoices are typically received, where the accounting or services verification takes place, and who is responsible for processing the invoice. The invoice validation process is defined by a seven-step process that includes verification of: schedule, quantity, quality, pricing, sales and use tax, mathematical accuracy, and documentation.

PMP-07 – Quality Assurance and Control [State St.]: Establishes the standards that ensure P&C products and services comply with quality requirements, codes, and applicable specifications. It includes individual requirements for inside plant electric, outside plant electric, and gas projects, as well as by project phase (e.g. engineering, procurement, construction, etc.). The degree of applicability dependent on project-specific factors (e.g. cost, risk, contracting strategy, etc.) with the Project (or Program) Manager responsible to assess and define the project-specific requirements.

PMP-08 – Project and Contractor Safety [Market St.]: Provides assistance to the P&C Project Teams in carrying out health and safety management of construction projects and is applicable to all P&C projects. It details the purpose and functions of the P&C Project Safety Management Program, which is intended to ensure continuous and controlled safety management between P&C and project contractors. The

procedure also outlines the requirements for safety management plans and site-specific health and safety plans, evaluating and pre-qualifying contractors, oversight, training, and other aspects of ensuring effective safety practices.

PMP-09 – Contract Administration [Toney's Brook]: Establishes the process for development, award, administration, and closeout for material, professional, and construction services contracts managed by P&C. It is structured around those four-phases of the contract lifecycle and provides key activities and responsibilities associated with each of these phases. It also details the change control process utilized on these types of contracts and the process for qualifying new vendors to ensure they meet PSE&G's standards.

PMP-10 – Project Construction Oversight [Ridgefield 4kV]: Establishes the process for P&C to ensure that all project work is completed in full compliance with the scope, plan, budget, schedule, and any contractual obligations. It provides a framework that identifies the oversight requirements by functional area (e.g. schedule and cost, labor workmanship, quality, safety, etc.) noting the process and requirements under each area.

PMP-11 – Project Risk Management [Woodlynne]: This procedure establishes the process of identifying, assessing, monitoring, controlling, and reporting project risks. It provides direction and responsibilities to each of those risk management aspects and is scalable based on the size and complexity of the project, with full implementation required for projects over $5 million. The procedure also explains the common risk management tools utilized in project management including the project risk register and risk management plan.

PMP-12 – Materials Management [Kingsland]: This procedure establishes the requirements for management of materials and equipment, including receiving, identification, handling, storage, maintenance, inspection, and management and control. Proper materials management supports improved productivity, reduces materials surplus, supports the project schedule, and can achieve cost savings. The procedure also includes the actions and responsibilities for treatment of removed equipment in demolition projects.

PMP-14 – Status Reporting [Academy]: This procedure establishes the requirements for producing, reviewing, and managing status reports for all P&C-managed projects. Actions and responsibilities are noted for the production of accurate and timely status reports. It also includes a description of the various types of status reports that may be generated depending on the project type and needs of stakeholders (e.g. portfolio status report, monthly variance explanation report, project closeout report, monthly cost reports, etc.).

PMP-15 – Inside Plant Commissioning [Ridgefield 13kV]: This procedure provides the requirements for inside plant commissioning, testing, and startup activities to ensure all project work is completed in full compliance with the required specifications. It is adaptable in scope to match the size and complexity of the individual project, with general concepts typically applied to all projects. The procedure covers all aspects of startup and commissioning, beginning with the planning phase, carrying through to scheduling requirements and actual project commissioning actions.

PMP-16 – Environmental Management Plan [Hasbrouck]: This procedure establishes the requirements for developing a project-specific environmental management plan to ensure compliance with applicable land use and environmental regulations. The requirements are aligned with the primary project phases (initiation, preliminary engineering/design, detailed engineering/design, construction/testing and

commissioning, and closeout/completion) and begins with development of a permitting matrix that defines all major regulatory permits required and the timeframes associated with obtaining them.

Findings & Observations:

- The P&C policies and procedures provide the project teams with the appropriate guidance to execute the projects under their responsibility. This set of policies and procedures is based on a foundation of project management practices that are aligned with industry standards.

D. Cost Assignments

In order to monitor PSE&G's compliance with cost accounting-related provisions of the Stipulation, the IM reviewed the Company's policies and procedures with respect to the relevant accounting practices. PSE&G's (the regulated utility) accounting practices are subject to Generally Accepted Accounting Principles (GAAP), as well as Federal Energy Regulatory Commission (FERC) practices and relevant instructions as contained in the Uniform Systems of Accounts. In addition, the company is subject to Financial Accounting Standards Board pronouncements as they relate to rate regulated entities, and practices accepted and/or mandated by the BPU. Finally, the Company is subject to the Sarbanes-Oxley Act of 2002, and specifically here, section 401, as it relates to accurate recording of fixed asset values. Collectively, this documentation provides the guidance needed to ensure proper accounting treatment.

Although interviews with the appropriate Accounting personnel are being scheduled, the IM, through its review to date of the Company's relevant accounting policies, has gained a general understanding of the Company's accounting practices that have bearing on the ES 2 Program. The IM began with a review of *Accounting Services Practice 630-4* regarding journal entries. This was done to ensure a procedure exists that supports the accuracy, timeliness and validity of the fundamental accounting information that is entered into the general ledger from which financial, cost, and other important business information is ultimately retrieved. Practice 630-4 covers proper accruals, required journal entry documentation, necessary review and approvals, and timely posting. The practice document is clear and comprehensive.

There are a number of general accounting areas the IM will be monitoring on a consistent basis arising from the provisions of the Stipulation. The IM has reviewed whether these areas are covered by specific policies beyond guidance promulgated by GAAP, FERC instructions, and BPU-approved accounting treatments. These general areas, along with subsets, are described below:

Proper Capitalization of ES 2 Program Project Costs: Proper capitalization of costs covers considerations ranging from when initial capitalization should begin as costs are recorded in Construction Work In Progress (CWIP) accounts, to the ultimate transfer of costs to plant-in-service for financial accounting and ratemaking purposes. The IM has reviewed the existence of documentation for each stage in this process, as noted below:

- Most projects begin with preliminary investigative work and feasibility studies before presentation to the relevant committees in the Company's capital approval process. When and under what circumstances these costs are capitalized or expensed is covered by *Accounting Practice 650-16, Practice for Use of Account E183*. To qualify as eligible for capitalization, project costs must, among other things, be approved as potentially part of the Company's long-term plan or mandated by regulators and proceed along a path in the capital approval process. If the project is denied at any point, costs are expensed. When the project is ultimately approved, costs incurred are journaled to a CWIP capital account. The account where pending costs are held is reviewed and approved quarterly for disposition. *Capitalization and Related Policies for*

PSE&G, 650-3, covers on-going criteria for capitalizing fixed asset costs, including differentiation of costs to be capitalized vs. expensed, as well as guidance on depreciable lives once costs are transferred to plant-in-service. Projects will be charged to or transferred into CWIP if they exceed $5,000 and take in excess of 60 days to complete, among other parameters. This also begins the capitalization of allowance for funds used during construction (AFUDC).

- Additional on-going cost capitalization guidance is also covered by Company *Property Record Unit Manual Policies GI-6, GI-7 and GI-8.* These documents provide further guidance on capitalization vs. expensing of costs incurred. Additionally, in cases where these policies do not specifically address aspects of a proposed capital project, the Company's *Sarbanes-Oxley Control FA005* requires a written determination from the Utility Property Accounting area.

- Once a project is substantially complete and ready for its intended use, or otherwise energized and carrying load, and/or considered used and useful, it is transferred out of CWIP to plant-in-service. This procedure is covered by *Accounting Practice 650-10, In-Service Transfers*. The responsible operating department notifies the Property Accounting department of the in-service date, and actual costs plus trailing costs are added to plant-in-service. AFUDC also ceases. This is the normal progression for accumulation and disposition of project costs.

- Finally, *Retirements and Transfers of Property, Practice 650-11*, gives additional guidance and sample journal entries for transfers and retirements of utility plant. The appropriate costs will be credited to depreciation reserve and debited to depreciable plant. As a result, no gains or losses will be recorded in the retirement of utility plant.

The IM will be monitoring the proper capitalization of costs (capital vs. expense), recordation of costs as ES 2 Program distribution costs, and the Company's CWIP accounts and asset transfers to plant on an on-going basis for compliance with proper accounting treatment of ES 2 Program expenditures.

Allocations of Overheads and Surcharges: The IM is in the process of scheduling interviews with appropriate personnel to discuss the area of allocations; however, due to its work in Energy Strong I, the IM has some familiarity with many of the Company's cost allocation policies and methodology as they are contained in its *Cost Accounting Manual, 660-1*. The Company follows a philosophy of allocating costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit based on either fully loaded hourly rates multiplied by the number of hours spent, or through a transactional count multiplied by a predetermined unit cost. Where direct charging is not possible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order issued in July 2003.

Cost allocations are performed automatically at each monthly closing within the Company's SAP system. SAP is an enterprise planning, accounting, and reporting software system. It is module-based, and the Company uses it as its system tool for general ledger, finance, and accounting/control (but not fixed assets).

The Stipulation requires the Company to follow its current practices with regard to capitalized overheads and calls for separate disclosure of allocation amounts in each rate adjustment filing. Based on work to date, the IM believes that the ES 2 Program should not create any changes to the Company's allocation methodology. Further, the IM anticipates that most allocated costs for ES 2 projects will come from

utility, rather than Service Company, cost pools. These expectations will be verified in interviews with Company personnel and will be tested when formal audits of the ES 2 Program commence.

Costs of Removal (COR), Net of Salvage: The Stipulation calls for separate disclosure of COR in each rate adjustment filing. The IM will be reviewing and disclosing charges to COR arising from the ES 2 Program.

Proper accounting treatment for costs of removal is detailed in *Capitalization and Related Policies for PSE&G, 650-3*. While the Stipulation does not directly address the accounting treatment of COR, PSE&G's historical accounting for these costs reflects their potential inclusion as capitalized costs under certain prescribed circumstances, along with amortization of costs of removal to the extent they are reflected in depreciation rates (or, in the case of gas assets, through an annual fixed amortization amount). The IM notes that the Company proposed a different method for recovery through depreciation expense of COR, or net salvage, in its last base rate filing (ER18010029 and GR18010030). The Company proposed to change the method of recovery for net salvage from its then-current five-year amortization method to what is known as the traditional method. This change was not reflected in the rate case stipulation, although new depreciation rates were adopted. The IM will discuss the effects of this change, if any, on accounting for COR in its interviews with Company personnel.

The IM intends to disclose gross COR in its periodic reporting but will track salvage values as well for accounting and ratemaking reconciliation purposes.

Allowance for Funds Used During Construction: The Stipulation permits recovery of AFUDC on ES 2 Program projects without regard to the maximum $691.5 million of costs eligible for recovery under the accelerated rate mechanism. In addition, the Stipulation states accrual of AFUDC should be calculated using the same methodology used for other distribution assets and consistent with Company policy. AFUDC should be calculated as permitted in FERC Order 561, which includes compounding on a semi-annual basis. The IM will be reviewing and disclosing both the amounts of AFUDC accrued and the Company's calculations of the AFUDC rate on an on-going basis. The IM will also monitor the initial recording and ultimate cessation of AFUDC with regard to projects within the ES 2 Program.

Guidelines for capitalization of AFUDC are provided by the Company's *Accounting Practice 650-9*, *Allowance for Funds Used During Construction and Rate Calculations*. The procedures therein define eligible projects, initial recording, the ultimate cessation of AFUDC, and the rate calculation formulas. Although the rate is determined annually, the Company historically has periodically recalculated and examined the AFUDC rate for material changes. An interim rate adjustment may occur if the recalculated rate deviates from the current rate by more than 25 basis points.

The Company's practices with respect to AFUDC are in accordance with Electric/Gas Plant Instruction 3(17) of the FERC's Uniform Systems of Accounts prescribed for public utilities (formerly FERC Order 561).

Findings & Observations:

- In review of PSE&G accounting practices, the IM has not discovered anything thus far in PSE&G's accounting for ES 2 Program projects that is in contravention of GAAP, FERC regulations, or any other known policy or practice.

1. Costs of Removal (COR)

COR generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Program Costs of Removal as of March 31, 2020 below itemizes the charges to COR for the first quarter of 2020, the fourth quarter of 2019 and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been zero in the ES 2 Program through March 31, 2020.

Table 5 – ES 2 Program Costs of Removal as of March 31, 2020

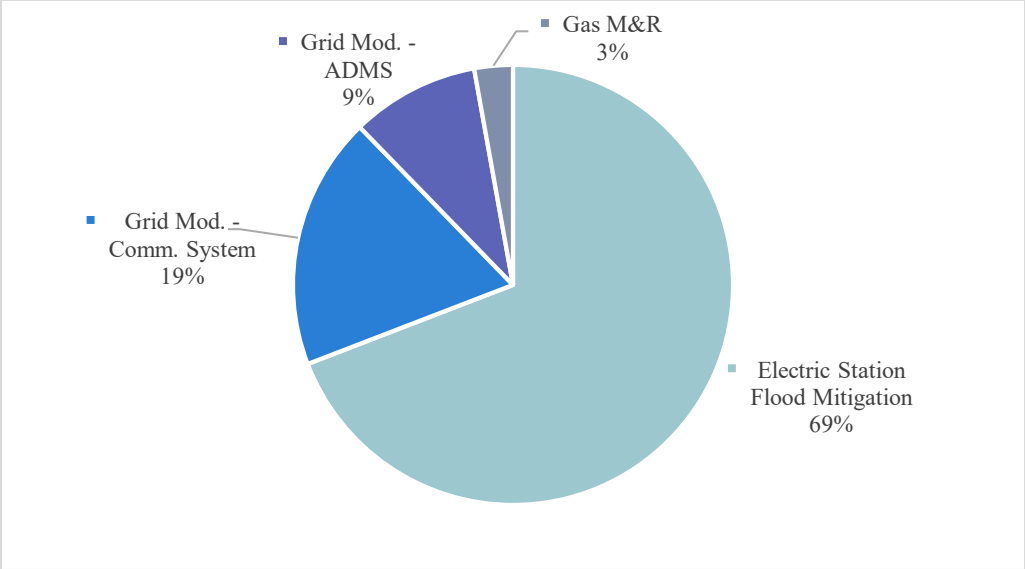
Subprogram	Q4 2019 COR	Q1 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$67,332**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$1,047,782**
Grid Modernization – Communications	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,115,114**

For the first quarter of 2020, Electric Station Flood Mitigation subprogram COR charges are attributed to the conversion of 4kV circuits at Market Street substation. Contingency Reconfiguration COR charges reflect work on the recloser replacement efforts in all districts.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

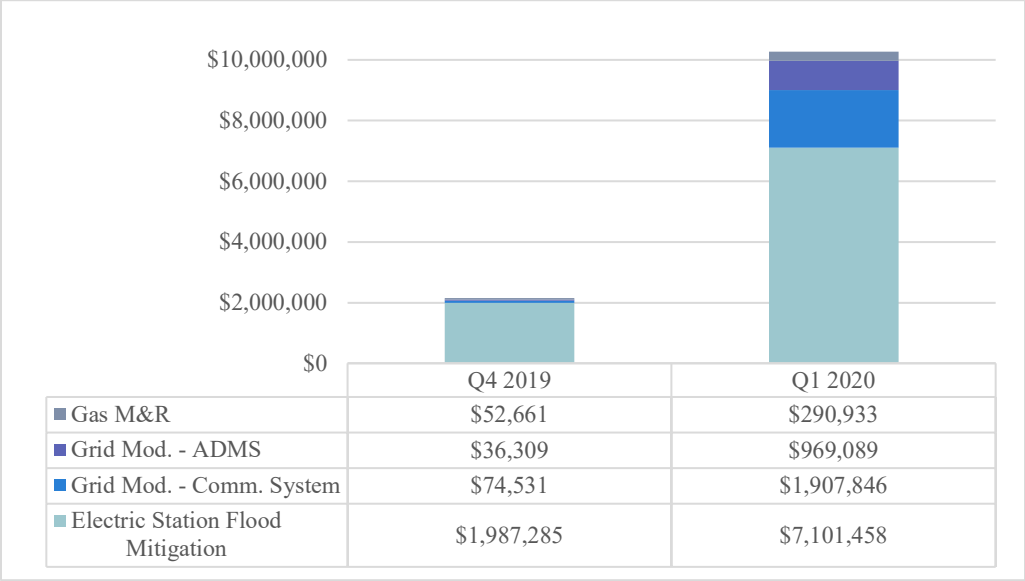
As of March 31, 2020, the ES 2 Program CWIP balance was $10.3 million, compared to $2.2 million as of December 31, 2019. The three largest components of March 31, 2020 CWIP were the conversion of circuits at Market Street and Ridgefield substations, and design and contract work at Waverly substation. The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 Program CWIP as of March 31, 2020** below.

Figure 1 – ES 2 Program CWIP as of March 31, 2020



In addition, **Figure 2 – ES 2 Program CWIP Balances by Subprogram** below depicts the composition of end-of-quarter CWIP balances by subprogram for both the fourth quarter of 2019 and the first quarter of 2020.

Figure 2 – ES 2 Program CWIP Balances by Subprogram



	Q4 2019	Q1 2020
Gas M&R	$52,661	$290,933
Grid Mod. - ADMS	$36,309	$969,089
Grid Mod. - Comm. System	$74,531	$1,907,846
Electric Station Flood Mitigation	$1,987,285	$7,101,458

There have been no transfers to date from CWIP to plant in-service.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 Program subprogram during the first quarter of 2020, the fourth quarter of 2019, and total ES 2 Program AFUDC accrued to date, is shown below in **Table 6 – ES 2 Program AFUDC**.

Table 6 – ES 2 Program AFUDC

Subprogram	Q4 2019 AFUDC	Q1 2020 AFUDC	Total AFUDC
Electric Station Flood Mitigation	**$9,887**	**$62,618**	**$72,505**
Contingency Reconfiguration	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$225**	**$14,572**	**$14,977**
Grid Modernization - ADMS	**$96**	**$7,092**	**$7,188**
Electric Stipulated Base	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$254**	**$2,590**	**$2,844**
Total	**$10,462**	**$87,052**	**$97,514**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. This rate is higher than the 2019 rate of 6.34%, primarily due to a significantly lower average short-term debt balance during the first quarter of 2020, with its lower associated component cost relative to the cost of equity and embedded cost of long-term debt. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2020, based on data as of March 31, 2020, the recalculated weighted average AFUDC accrual rate (6.95%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the first quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 Program projects during the first quarter of 2020 increased significantly over AFUDC accrued during the fourth quarter of 2019 as the result of the large increase in total average CWIP balances.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to first quarter 2020 ES 2 Program project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 Program projects. The IM will continue to review future ES 2 Program AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

E. System Performance

From the commencement of the ES 2 Program through the end of the first quarter of 2020, there have been no Major Events. The IM has additionally requested and received baseline circuit performance metrics from the prior five-year period to help facilitate its analysis of PSE&G's system performance.

III. Project Status

A. Electric Station Flood Mitigation

The Stipulation established the 16 electric stations that comprise the Electric Station Flood Mitigation subprogram and included an identification of the anticipated mitigation method for each station, with 14 identified with raise and rebuild and two identified with elimination as the preferred mitigation method.

The Electric Station Flood Mitigation subprogram is led by Christina Ker, with the subprogram organization split between standalone stations (Market Street, Leonia, Ridgefield 4kV, Ridgefield 13kV, Waverly, and Constable Hook) and stations that are aligned with 69kV projects (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley). For the standalone stations, there are three project managers assigned to the six stations; and for the stations aligned with 69kV projects, there is a Division Lead overseeing projects within their respective Division to whom project managers report.

The projects aligned with 69kV projects are treated as separate projects but utilized a common project team. This benefits the ES 2 Program as it allows cost sharing rather than having entirely separate project teams, in addition to benefiting from a common team that has intimate familiarity with any interdependencies between the projects. Other benefits realized by these 69kV-aligned projects include: having a common site plan submitted to the municipalities for review (if the 69KV project has not already started); sharing leased laydown space; and, from having the 69kV construction start first (providing more information on below grade condition and water table levels).

Each of the projects within the subprogram is governed by a PEP and the IM has reviewed all the PEPs developed to date (some of the project PEPs are still in development), finding them to be robust documents that contain all the required information and will be an effective tool in managing and monitoring the projects' execution. Rather than repeat all the information contained in the PEP for each project, the IM has provided selected commentary on different functional areas for the individual projects as discussed in the specific project subsections that follow.

Licensing and permitting on the Electric Station Flood Mitigation projects is managed by a dedicated licensing and permitting manager assigned to each project, who interfaces with the project team, develops a permitting matrix for each project, and is responsible for obtaining the necessary permits. Public outreach on the projects is handled by PSE&G's public outreach group, who informs public stakeholders of relevant project information, answers questions from the public, and holds public workshops as needed.

The subprogram was initiated following approval of the ES 2 Program on September 11, 2019. PSE&G then held a kickoff meeting with its internal stakeholders on October 10, 2019. This internal kickoff meeting reviewed all 16 projects in the Electric Station Flood Mitigation subprogram. The planning process has been more integrated on the ES 2 Program than in the original Energy Strong Program, including centralized work planning and scheduling and a more robust front end planning effort that supported a more thorough stakeholder review, which should help limit scope changes, design layout issues, and similar challenges. Shortly after the subprogram kickoff meeting, the process to bid out major equipment and A/E support needed for the subprogram was initiated, and through the end of the first quarter of 2020, work continued to advance based on the anticipated schedules for each of the projects. Relative to Covid-19 impacts, to date there has been minimal disruption to the subprogram, with the primary change being in-person meetings transitioning to virtual settings. In addition, construction on the

Ridgefield 4kV project had a one-day stoppage from the local municipality stopping all work in response to Covid-19 (which was followed one day later by a directive from the Governor that allowed utility work to resume). A summary of the subprogram plan as of the end of 2019 and as of March 31, 2020 is provided below in **Table 7 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule**.

Table 7 – ES 2 Electric Station Flood Mitigation Milestone Schedule

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Mar. 2020		KO				C				IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020			KO							C					IS				CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Mar. 2020		KO						C						IS		CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Mar. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS	CO (Q2)
	Mar. 2020						KO				C							IS		CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020			KO		C									IS				CO	
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Mar. 2020			KO					OS/C					CO						
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020			KO											C			IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020	*Schedule Under Development*																		
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Mar. 2020			KO		C								IS			CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Mar. 2020			KO	C					OS			CO							
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Mar. 2020		KO					C						IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Mar. 2020			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Mar. 2020			KO			C												IS	CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Mar. 2020		KO												C			IS		CO (Q2)

December 31, 2023 - Energy Strong 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service; OS = Out-of-Service (if eliminated); CO = Closeout -Actuals are indicated with an underline

A summary of the subprogram status as of the end of the first quarter of 2020 is provided below **Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2020**. Additional information on the individual projects is discussed in the respective project's subsection.

Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	7	Academy Street; Hasbrouck Heights; Kingsland; Market Street; State Street; Toney's Brook; Woodlynne
Major Equipment POs	7	Academy Street; Hasbrouck Heights; Leonia; Ridgefield 13kV; State Street; Toney's Brook; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	10	Academy Street; Clay Street; Kingsland*; Market Street*; Ridgefield 13kV*; Ridgefield 4kV*; State Street*; Toney's Brook; Waverly; Woodlynne
Construction Start	2	Market Street; Ridgefield 4kV
**-Indicates PSE&G internal resources are serving as the A/E.*		

The IM evaluated PSE&G's vendor selection decision for the switchgear at multiple projects within the Electric Station Flood Mitigation subprogram, some of which were bid in project bundles as follows:

- 5kV-rated Switchgear: State Street, Toney's Brooke, Woodlynne;
- 5kV-rated Switchgear: Hasbrouck
- 15kV-rated Switchgear: Kingsland, Leonia (2), Meadow Road, Ridgefield 13kV (2)
- 15kV-rated Switchgear: Fairmount
- 38kV-rated Switchgear: Waverly

In each project sampled, PSE&G followed the same comprehensive bid evaluation process used in the original Energy Strong Program that saw multiple bidders respond, with PSE&G reviewing the technical and commercial aspects of the bids before making a recommendation to award based on a weighted rating criteria.

The current project estimates, including base and R&C amounts, is shown below in **Table 9 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2020**. This table also shows the current estimate level based on PSE&G's estimating processes, the actual spend and percentage of actuals to estimate as of the end of the first quarter of 2020, and the forecasted in-service date.

Table 9 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate
1. Academy Street	Office	$12,600,000	$4,400,000	$17,000,000	$250,291	1%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$336,116	1%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$69,647	1%

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$343,727	2%
5. Kingsland	Study	$7,100,000	$2,900,000	$10,000,000	$212,398	2%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	$321,167	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$289,114	1%
8. Market Street	Study	$24,200,000	$5,800,000	$30,000,000	$2,189,906	7%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$206,074	2%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$173,611	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$523,271	2%
12. Ridgefield 4kV	Study	$16,800,000	$4,300,000	$21,100,000	$836,542	4%
13. State Street	Office	$21,200,000	$7,400,000	$28,600,000	$205,878	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$327,687	2%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$459,454	1%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$351,400	2%
Subprogram Total		**$309,000,000**	**$80,000,000**	**$389,000,000**	**$7,096,284**	**2%**

Findings & Observations

- The IM finds the organization of the subprogram, and specifically the split between 69kV-aligned projects and standalone projects, to be an appropriate arrangement that should benefit each of the projects by recognizing the varying complexities involved in these alignments, as well as provide potential cost benefits for the 69kV-aligned projects.
- The majority of projects within the subprogram have had both a kickoff meeting and a review of the key drawings, with the exception being the Constable Hook, Lakeside, and Orange Valley projects that are tied to 69kV projects that are in the planning and development stages.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Academy Street

The original Academy Street substation scope called for replacing the substation's existing 4kV feeder rows with 13kV sheltered aisle switchgear that is elevated one foot above the flood elevation. After further evaluation, PSE&G determined that the preferred mitigation method for this substation was to demolish the existing station and convert the outside plant circuits from 4kV to 13kV, transferring the

load to the nearby Fairmount station, as documented in a notice to the BPU on April 16, 2020. The final scope achieves the same primary objective, which is to eliminate flood related impacts, while doing so at a lower estimated cost (original scope was estimated at $17.0 million vs. the final scope at $12.8 million[2]). The Fairmount station is located less than 0.5 miles from the existing Academy Street substation and has multiple Academy Street circuits in close proximity, so minimal new circuit mileage is required, and it will not increase distribution circuit exposure. On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the change (as well as the change to the State Street substation) without additional information and clarification on the changes.

The Academy Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the project charter/project authorization and status reporting.

- Project Charter/Project Authorization: The Project Management Institute's (PMI's) Project Management Body of Knowledge (PMBOK) provides that the project charter is the "document that formally authorizes the existence of a project and provides the project manager with the authority to apply organizational resources to project activities. It documents the high-level information on the project…"[3] Within the Academy Street PEP, it notes the project investment request serves as the charter document for the project, which is provided as an attachment to the PEP. The Academy Street investment request form provides the annual estimated expenditures on the project, a summary of the project scope, the assumptions utilized, major timing commitments (e.g. long-lead equipment, permitting, etc.), and other similar summary information that defines the project. The IM finds the Academy Street project charter and project authorization, as established by the investment request form, aligns with industry standards.
- Status Reporting: The PMBOK provides that "During project execution, the work performance data is collected and communicated to the applicable controlling processes for analysis. Work performance data analysis provides information about the completion status of deliverables and other relevant details about project performance."[4] Within the Academy Street PEP, it notes that status reports will include status and forecast information, referencing the PMP-14 procedure on status reporting and providing a sample monthly progress report as an attachment. The monthly progress report reviews the summary activities on the project, provides functional performance indicators, and cost, schedule, and risk information. The IM finds the Academy Street project status reporting, and specifically the sample monthly progress report, aligns with industry standards.

Through the end of the first quarter of 2020, approximately $250,000 was spent on the Academy Street project, primarily on project management and engineering costs. Notable activities completed to date include:

- Project kickoff meeting held;
- Issuance of key drawing packages;
- Permitting matrix completed;

[2] Note: the Academy Street project Study level estimate, which features the updated estimate based on the change in mitigation method, is expected to go for approval before the Utility Review Board (URB) in May 2020. The $17.0 estimate shown in this report is the last approved estimate for the project.
[3] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 81, 2017
[4] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 92, 2017

- A/E contract was awarded, and detailed design has commenced;
- Licensing and permitting package for the project issued; and,
- Switchgear purchase order was awarded, and delivery is scheduled for November 2020.

Upcoming activities in the second quarter of 2020 include commencement of detailed design and civil, demolition, and electrical drawings issued for review. The actual spend by quarter for the Academy Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$150,398	$99,893	$250,291	$17,000,000	1%

2. Clay Street

The Clay Street substation scope calls for building new manholes, feeder rows, switchgear, buildings, and associated equipment to allow relocation of existing 4kV transformer connections, circuits, and capacitor bank to the new 4kV switchgear. The existing 4kV switchgear at the substation is housed in the ground floor of the station building, which is below the flood elevation level and the site has a history of flooding from the adjacent sanitary/storm water pumping station. By raising and rebuilding the equipment, the Clay Street substation will have increased reliability and resiliency against flooding impacts and will increase the lifespan of the station.

Through the end of the first quarter of 2020, $336,116 was spent on the Clay Street project. Notable activities completed to date include:

- Project kickoff meeting held;
- Issuance of key drawing packages;
- Permitting matrix completed; and,
- A/E contract was awarded.

Upcoming activities in the second quarter of 2020 include locking the scope and commencing design on the licensing and permitting package. The actual spend by quarter for the Clay Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$116,409	$219,707	$336,116	$42,000,000	1%

3. Constable Hook

The Constable Hook substation scope calls for modifying the existing unit substation 8002 foundation to raise it one foot above the flood elevation level (as it currently sits two and a half feet below it), removing the existing unit substation 8001 and its structures and foundations to install a new unit substation 8001 (this will involve temporary installation of the unit sub to provide service during construction of the new foundation and oil containment). By implementing this scope, the Constable Hook substation will increase its reliability and resiliency against flooding impacts and benefit from an increased station lifespan.

Through the end of the first quarter of 2020, the Constable Hook project largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the

same area still being reviewed. The actual spend by quarter for the Constable Hook project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$17,889	$51,758	$69,647	$5,300,000	1%

4. Hasbrouck Heights

The Hasbrouck Heights substation scope calls for replacing the existing 4kV feeder rows with 4kV sheltered aisle switchgear and related equipment. The existing equipment is below the flood elevation level, and the new equipment will be installed one foot above the flood elevation level in order to increase the reliability and resiliency of the substation, while also extending the lifespan of the station.

The Hasbrouck Heights PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the scope management plan and the environmental management plan.

- Scope Management Plan: The PMBOK provides that the project scope statement is "the description of the project scope, major deliverables, assumptions, and constraints."[5] Within the Hasbrouck Heights PEP, the project scope document is provided as an attachment to the PEP. The Hasbrouck Heights project scope document provides an overview of the project, its goals and objectives, the projected in-service and completion dates, the project deliverables, assumptions, risks, constraints, operating contingency, an environmental land use checklist, lists responsibilities for design, construction, and support, and similar information related to defining the project scope. The IM finds the Hasbrouck Heights project scope document aligns with industry standards for a project scope statement and can be effectively used to monitor and validate the scope.
- Environmental Management Plan: The Construction Management extension to the PMBOK notes that "The project environmental management plan essentially defines the strategy or methodology to be adopted by the performing organization to undertake environmental management and to fulfill the requirements of the project…"[6] Within the Hasbrouck Heights PEP, environmental compliance/remediation and soil, groundwater, and waste management are included as distinct PEP sections. For this site, the PEP notes a Licensed Site Remediation Professional will be used until monitoring wells are reinstalled (expected to be installed during 2020), with the New Jersey Department of Environmental Protection (NJDEP) still reviewing the soil remedial action report. It also provides project-specific strategies for soil and groundwater management to ensure compliance with regulations and requirements. The permit matrix for the project is also provided as an attachment to the PEP and lists the permits by agency with the expected permit approval duration and additional notes as appropriate (i.e. explaining the applicability or non-applicability of specific permits as well as any assumptions).

[5] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 135, 2017
[6] Project Management Institute, *Construction Extension to The PMBOK Guide Third Edition*, Second Edition, p. 147, 2007

Through the end of the first quarter of 2020, $343,727 was spent on the Hasbrouck Heights project. The major activities completed to date on the Hasbrouck Heights project include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (4kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include preparing and issuing the licensing and permitting package and commencing detailed engineering design. The actual spend by quarter for the Hasbrouck Heights project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$149,848	$193,879	$343,727	$18,000,000	2%

5. Kingsland

The Kingsland substation scope calls for rebuilding and replacing the existing 13kV feeder row switchgear that sits below the flood elevation level with new 13kV sheltered aisle switchgear that will be installed above the flood elevation level. This will increase the reliability and resiliency of the substation against flooding impacts and increase the lifespan of the station.

The Kingsland PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the schedule management plan and materials management.

- Schedule Management Plan: The PMBOK provides that the schedule management plan "is a component of the project management plan that establishes the criteria and the activities for developing, monitoring, and controlling the schedule."[7] Within the Kingsland PEP, the schedule management plan is included as a section of the main PEP. The Kingsland schedule management plan notes the schedule will be managed based on project objectives and resource constraints, including identification of all interconnections, interfaces, and interdependent deliverables. On a monthly basis, the schedule will be reviewed and updated accordingly to reflect actual progress and planned activities. The IM finds the Kingsland schedule management plan aligns with industry standards for a schedule management and can be effectively used to monitor and control the schedule.
- Materials Management: The topic of materials management can be considered part of the larger procurement process, and as such, is often not a focal point of industry standards on project management. However, the Construction Management Association of America (CMAA) notes that "Prior to construction, the [construction manager] identifies long lead materials and equipment for pre-purchasing…"[8] Within the PEP, the major equipment required for the project is identified (13kV sheltered aisle switchgear) and included in the risk register, schedule, and other key project documents. Also, the Kingsland PEP references to the PEP-12 procedure on materials management for the requirements regarding material and equipment receiving,

[7] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 135, 2017
[8] Construction Management Association of America, *Standards of Practice*, p. 21, 2015

identification, handling, storage, and control of these processes. The IM finds the Kingsland materials management plan appropriately utilizes existing PSE&G processes and also has identified the major and long-lead equipment that aligns with industry standards.

Through the end of the first quarter of 2020, $212,398 was spent on the Kingsland project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Major equipment (13kV sheltered aisle switchgear) purchase order issued; and,
- Commencement of the licensing and permitting design package.

Upcoming activities in the second quarter of 2020 include vendor drawings (mechanical and wiring) submitted to PSE&G. The actual spend by quarter for the Kingsland project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$104,112	$108,286	$212,398	$10,000,000	2%

6. Lakeside Avenue

The Lakeside Avenue substation scope calls for replacing the existing 4kV building that sits below the flood elevation level with 4kV sheltered aisle switchgear, including reactors and regulators, that will be installed one foot above the flood elevation level. The scope also includes expanding the station fence to encompass additional property acquired and installing (and later demolishing) a temporary 26kV control house to maintain service. This will increase the reliability and resiliency of the Lakeside Avenue substation against flooding impacts and increase the lifespan of the substation.

Through the end of the first quarter of 2020, $321,167 was spent on the Lakeside Avenue project. The project largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same sites still being reviewed. The actual spend by quarter for the Lakeside Avenue project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$148,943	$172,224	$321,167	$36,100,000	1%

7. Leonia

The Leonia substation scope calls for expanding the existing fence to the property line, installing new 13kV sheltered aisle switchgear above the flood elevation level, demolishing existing 13kV structures that are below the flood elevation level, and installing new manhole, ducts and feeders to support the 13kV system. This will increase the reliability and resiliency of the Leonia substation against flooding impacts and increase the lifespan of the substation.

Through the end of the first quarter of 2020, $289,114 was spent on the Leonia project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include completion of the permitting matrix, constructability reviews, and locking the scope. The actual spend by quarter for the Leonia project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$44,792	$244,323	$289,114	$32,200,000	1%

8. Market Street

The Market Street substation scope calls for converting the 4kV outside plant circuits to 13kV, feeding the 13kV circuits from the Locust Street and Deptford substations, and eliminating the Market Street substation. The substation's existing 4kV feeder rows are below the flood elevation level and PSE&G identified that open capacity at the neighboring substations was available to increase the reliability of the Market Street 4kV network.

The Market Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on the project estimating/cost management plan and the health and safety management plan.

- Project Estimating/Cost Management Plan: The PMBOK provides that cost management "includes the processes involved in planning, estimating, budgeting, financing, funding, managing, and controlling costs…"[9] Within the Market Street PEP, the cost management plan is included as a section of the main PEP. The Market Street cost management plan reviews the estimating process used on the project, noting the Study level estimate will serve as the project baseline estimate until the future estimates at the Conceptual and Definitive levels are completed, at which point they will become the new project targets for monitoring and reporting costs. The cost management plan goes on to explain the budgeting process consists of two primary elements – the plan and the forecast, with updates to the budgeted plan being managed through the change control process and with the actuals and annual to-go cash flow updated on a monthly basis. The IM finds the Market Street cost management plan aligns with industry standards for project cost management and can be effectively used to monitor and control costs.
- Health and Safety Management Plan: The Construction Management extension to the PMBOK notes that project safety management processes "include all activities of the project sponsor/owner and the performing organization which determine safety policies, objectives, and, responsibilities so the project is planned and executed in a manger that prevents accidents…The performing organization implements the safety management system through the policy, procedures, and processes of safety planning, safety assurance, and safety control, and undertaking continuous improvement activities throughout the project, as appropriate."[10] Within the Market Street PEP, it notes that the PMP-08 procedure on project and contractor safety will

[9] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 231, 2017
[10] Project Management Institute, *Construction Extension to The PMBOK Guide Third Edition*, Second Edition, p. 119, 2007

be implemented. It also provides that the contractor will submit a project health and safety plan for approval prior to construction. The Market Street site is a designated Superfund study area and the PEP notes that the project team has engaged Environmental Protection Agency (EPA) representatives and will follow appropriate guidance on health and safety measures, including utilizing trained hazardous water operations and emergency response (HAZWOPER) personnel as appropriate.

Through the end of the first quarter of 2020, $2,189,906 was spent on the Market Street project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Commencement of detailed design; and,
- Start of outside plant construction.

Upcoming activities in the second quarter of 2020 include civil and electrical drawings being issued for construction. The outside plant area of the Market Street site (along the road) was identified as having radioactive soil, which had the potential to affect the project completion; however, PSE&G engaged qualified contractors to handle the required soil removal in alignment with the project schedule. The total estimated costs for the environmental contaminated soil issue is $2.3 million and is included in the current $30 million estimate. This $2.3 million includes the cost of excavation for installation of poles on the outside plant scope and certified contractor testing, sampling, soil removal, and Sonotube installations.

The actual spend by quarter for the Market Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$251,193	$1,938,713	$2,189,906	$30,000,000	7%

9. Meadow Road

The Meadow Road substation scope calls for replacing the existing five 13kV individual feeder rows that sit below the flood elevation level with new 13kV sheltered aisle switchgear on elevated platforms one foot above the flood elevation level. This will increase the reliability and resiliency of the Meadow Road substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter of 2020, $206,074 was spent on the Meadow Road project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include locking the scope and issuing the licensing and permitting package. The actual spend by quarter for the Meadow Road project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$63,128	$142,946	$206,074	$9,000,000	2%

10. Orange Valley

The Orange Valley substation scope calls for replacing the existing 4kV feeder rows that sit below the flood elevation level with 4kV sheltered aisle switchgear to be installed on elevated platforms one foot above the flood elevation level. This will increase the reliability and resiliency of the substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter of 2020, $173,611 was spent on the Orange Valley project, which largely remained in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same sites still being reviewed. The actual spend by quarter for the Orange Valley project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$77,029	$96,582	$173,611	$26,600,000	1%

11. Ridgefield 13kV

The Ridgefield 13kV substation scope calls for replacing existing 13kV feeder rows that are currently below the flood elevation level with two 13kV shelter aisle switchgears on an elevated structure one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Ridgefield 13kV PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on invoice management and inside plant commissioning.

- Invoice Management: The PMBOK provides that "Control Procurements has a financial management component that involves monitoring payments to the seller."[11] Within the Ridgefield 13kV PEP, invoice management is included as a section of the main PEP. The Ridgefield 13kV invoice management plan notes that the Project Team, interfacing with construction supervision, inside plant leads, and engineering, will ensure that all invoices are submitted based on monthly cycle time to help prevent re-accruals and support forecast accuracy. The PMBOK also notes that invoices are one type of work performance data, adding that "…work performance data on cost may include funds that have been expended. However, to be useful, that data has to be compared to the budget, the work that was performed, the resources used to accomplish the work, and the funding schedule. This additional information provides the context to determine if the project is on budget or if there is a variance…Interpreting work performance data and the additional information as a whole provides a context that provides a sound foundation for project

[11] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 494, 2017

decisions."[12] To fully appreciate how this is detailed in the Ridgefield 13kV PEP, the cost management plan must also be taken into consideration. In this section of the PEP, it details the cash flow forecasting efforts to be undertaken by the project team and supporting functional resources. The IM finds the invoice management processes support the industry standards for effective cost forecasting and can be effectively used to monitor and control project costs.

- Inside Plant Commissioning: The CMAA notes in its *Construction Management Standards of Practice* that "…the commissioning plan must be in concert with the project sustainability plan and the sustainability requirements of the owner…The project goals and objectives and the commissioning plan should be coordinated and focus on achieving the same project outcome."[13] The commissioning plan within the Ridgefield 13kV PEP notes that it is based off the requirements established by the inside plant commissioning procedure (PMP-15). It also establishes the roles and responsibilities of the key personnel involved in commissioning, with the PSE&G Project Construction Supervisor responsible for directing the testing, commissioning, and energization of the project in order to provide for seamless turnover of the project systems and equipment to the Division Operations Team. The Commissioning Engineer, while responsible for development of equipment-specific commissioning plans, also is involved in the development of the project scope and design review process in order to ensure constructability, identification of outage requirements, and avoidance of conflicts during startup activities. The IM finds the commissioning plan as described in the PEP and supported by the PMP-15 procedure aligns with industry standards for project commissioning and can be effectively used to ensure the project's commissioning supports the overall project goals and objectives.

Through the end of the first quarter of 2020, $523,271 was spent on the Ridgefield 13kV project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked; and,
- Major equipment (13kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include issuing the licensing and permitting package and release of civil and electrical construction design packages for construction. The actual spend by quarter for the Ridgefield 13kV project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$205,982	$317,289	$523,271	$25,500,000	2%

12. Ridgefield 4kV

The Ridgefield 4kV substation scope calls for eliminating the 4kV feeder rows that currently sit below the flood elevation level and transferring the load to the 13kV system. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

[12] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 109, 2017
[13] Construction Management Association of America, *Standards of Practice*, p. 121, 2015

The Ridgefield 4kV PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on project construction oversight.

- The PMBOK includes only limited discussion on oversight, essentially just that the project manager has oversight responsibility.[14] Other industry standard publications, such as those from the CMAA take similar stances, noting that the construction manager provides oversight for the entire project to deliver the project on time, at or under budget, and to the expected standard of quality, scope, and function.[15] In essence, oversight takes place within the different project functions (e.g. schedule, cost, scope, etc.). Within the Ridgefield 4kV PEP, it provides that the Project Construction Oversight procedure establishes the requirements for construction oversight and specifically details the unique responsibilities concerning outside plant conversion work on the project. Within the different project functions, additional structure is provided as to the expected oversight and reviews of the project schedule, costs, and other project functions. The IM finds the project construction oversight processes are established to effectively monitor that project goals and objectives are fulfilled.

Through the end of the first quarter of 2020, $836,542 was spent on the Ridgefield 4kV project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Detailed engineering commenced; and,
- Outside plant construction started.

Upcoming activities in the second quarter of 2020 include locking the scope, issuing the civil works contract, and commencing civil construction. The actual spend by quarter for the Ridgefield 4kV project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$143,414	$693,128	$836,542	$21,100,000	4%

13. State Street

The original State Street substation scope called for replacing the existing 4kV switchgear, feeder rows, and transformers that currently sit below the flood elevation level with new equipment that will be installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station. On April 16, 2020, PSE&G issued to the BPU a notice of change in mitigation method on this substation (and the Academy Street substation). The State Street substation is located within the City of Camden and is both within a flood hazard area and within the City's redevelopment zone. The City and Camden County have informed PSE&G they are strongly opposed to the substation expansion required for flood mitigation work at the current site. PSE&G researched alternatives and with recommendation from the City identified property at Cooper Street that would be suitable for rebuilding the State Street substation. The new property is an

[14] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 29, 2017
[15] https://www.cmaanet.org/about-us/what-construction-management

undeveloped parcel located outside the flood hazard area and the redevelopment zone, however, it will require extensive underground installation (duct banks, manholes) that was not part of the original project scope and will result in a significant increase to the project's estimate (from $28.6 million to $45.1 million). On April 22, 2020, Rate Counsel responded to PSE&G's notice indicating it objects to the change (as well as the change to the Academy Street substation) without additional information and clarification on the changes.

The State Street PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on quality assurance and quality control.

- The PMBOK provides that "Plan Quality Management is the process of identifying quality requirements and/or standards for the project and its deliverables, and documentation how the project will demonstrate compliance with quality requirements and/or standards."[16] Within the State Street PEP, quality assurance and quality control steps are included as a section of the main PEP and establishes the strategies to be implemented on the project for effective quality assurance and quality control, including responsibilities for the project team, project manager, contractor, and vendor/supplier. The general quality assurance and quality control plan is provided as an attachment to the PEP and provides additional detail into the quality management actions and responsibilities, including establishing the strategy and requirements for the different project functional areas (e.g. engineering, procurement, construction, etc.). The IM finds the quality management processes support the industry standards for effective quality assurance and quality control and can be effectively used to ensure project-specific requirements are fulfilled.

Through the end of the first quarter, $205,878 was spent on the State Street project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Licensing and permitting package submitted; and,
- Major equipment (4kV sheltered aisle switchgear) purchase order issued.

Upcoming activities in the second quarter of 2020 include commencing detailed engineering design. The actual spend by quarter for the State Street project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$77,590	$128,288	$205,878	$28,600,000	1%

14. Toney's Brook

The Toney's Brook substation scope calls for replacing the existing 4kV switchgear, feeder rows, transformers, and 26kV equipment that sits below the flood elevation level with new equipment to be

[16] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 494, 2017

installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Toney's Brook PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on contract administration.

- Within the Toney's Brook PEP, the contracting strategy and contract administration responsibilities are included as an attachment to the PEP. The contract administration responsibilities detail the specific responsibilities of the PSE&G personnel, covering the contracting process through the development of bid packages, review and awarding of bids, and managing contracts including change control processes. The PMBOK provides that "Defining roles and responsibilities related to procurement should be done early in the Plant Procurement process" and notes typical steps such as preparing scopes of work, preparing bid documents, evaluating proposals, etc.[17] that are included in the Toney's Brook contract administration responsibilities. The IM finds the contract administration processes align with industry standards and can be used to ensure effective contract management practices are utilized.

Through the end of the first quarter of 2020, $327,687 was spent on the Toney's Brook project. The major activities completed to date include:

- Completion of the contingency plan (part of the companion 69kV project);
- Review of key drawings;
- Submittal of the licensing and permitting packages;
- Issuance of the major equipment purchase order (4kV sheltered aisle switchgear);
- Award of the A/E contract; and,
- Locking of the scope.

Upcoming activities in the second quarter of 2020 include design freeze on the switchgear arrangement, mechanical, and controls, and preparation of the civil design package (issued for review). The actual spend by quarter for the Toney's Brook project compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$211,940	$115,747	$327,687	$19,700,000	2%

15. Waverly

The Waverly substation scope calls for rebuilding the 26kV switchgear and transformers and building new 4kV feeder rows, which will be one foot above the flood elevation level, in addition to the demolishing of the existing 26kV yard, the over 80-year old Class A building and associated old 4kV equipment. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

Through the end of the first quarter, $459,454 was spent on the Waverly project. The major activities completed to date include:

- Kickoff meeting held;

[17] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 468, 2017

- Key drawings reviewed; and,
- Geotech services contract awarded.

Upcoming activities in the second quarter of 2020 include issuing the purchase order for major equipment (26kV and 4kV sheltered aisle switchgear), awarding the A/E contract, and locking the scope. The actual spend by quarter for the Waverly project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$103,748	$355,706	$459,454	$35,400,000	1%

16. Woodlynne

The Woodlynne substation scope calls for replacing the existing 4kV feeder rows/sheltered aisle switchgear that currently sits below the flood elevation level with new equipment to be installed one foot above the flood elevation level. This will increase the reliability and resilience of the substation against flooding impacts and increase the lifespan of the station.

The Woodlynne PEP follows the P&C PMP set of procedures discussed above in **Section C.2.** On this PEP, the IM is providing comments on risk management.

- The PMBOK provides that risk management "includes the processes of conducting risk management planning, identification, analysis, response planning, response implementation, and monitoring risk on a project. The objectives of project risk management are to increase the probability and or/impact of positive risks and to decrease the probability and/or impact of negative risks, in order to optimize the chances of project success."[18] Within the Woodlynne PEP, it notes that project risks were identified and assessed with corresponding strategies to control the risks identified. The project's risk register is attached as an attachment to the PEP and will be reviewed on a monthly basis during execution. The IM finds the risk register developed for the Woodlynne project aligns with industry standards for risk management, including quantifying the risk impacts and identifying mitigation plans, and can be effectively used to ensure project risks are identified, managed, and controlled.

Through the end of the first quarter of 2020, $351,400 was spent on the Woodlynne project. The major activities completed to date include:

- Kickoff meeting held;
- Key drawings reviewed;
- Permit compliance matrix completed;
- Scope locked;
- Major equipment (4kV sheltered aisle switchgear) purchase order issued; and,
- A/E contract awarded.

Upcoming activities in the second quarter of 2020 include preparing and issuing the licensing and permitting package and commencing detailed engineering design. The actual spend by quarter for the Woodlynne project as compared to the last approved estimate is provided below.

[18] Project Management Institute, *A Guide to the Project Management Body of Knowledge – PMBOK Guide,* Sixth Edition, p. 395, 2017

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$110,982	$240,418	$351,400	$19,400,000	2%

B. Contingency Reconfiguration

The Stipulation identified the Contingency Reconfiguration subprogram to include up to $145 million invested in increasing system resiliency through implementation of contingency reconfiguration strategies that include: increasing sections in present loop designs by utilizing reclosers; converting all existing two-section overhead 13kV circuits to three-section circuits by installing additional three-phase reclosers, and installing single-phase recloser devices on branch lines that operate with only fuses.

The Contingency Reconfiguration organization is led by Donald Gordon, supported by Bob Kirk (Senior Project Manager), Nicole Severt (PMO Manager), and with subprogram leads at each of the Divisions. Under this arrangement, the subprogram is centrally managed, with execution carried out at the Division-level following their own execution processes. As part of the management of the subprogram, monthly unit targets are established for the Divisions, with status calls held weekly with all Divisions. Additionally, direction was given to the Divisions to push engineering out ahead of execution to support maximum flexibility in carrying out the work. This flexibility has assisted in minimizing Covid-19 impacts, as the permitting process has often been extended due to the process now requiring exchange of permitting documents to take place over the mail, rather than in-person.

The selection criteria for projects under the Contingency Reconfiguration subprogram began with a pool of all overhead 13kV circuits (excluding existing three-section circuits) and the worst performing overhead 4kV circuits (excluding existing two-section circuits). The priority is based on highest customer impact and begins with 13kV circuits, then 4kV feeder reclosers, and followed by 4kV tie reclosers. Additional detail on the specific selection criteria is provided as follows:

- 13kV Circuits: each of the two sections are evaluated based on historical customer outage data, if one of the two sections has a much greater customer interruption rate, then a recloser is added to split that section; if the two sections are relatively close in their performance, the circuit is split into thirds. As a result, all 13kV circuits with overhead mileage will be upgraded from 2 to 3 section reclosers.
- 4kV Circuits: these circuits were not originally designed with sectionalizing reclosers, so a customer interruption analysis was performed and concluded there is value to sectionalizing the worst performing 4kV circuits based on the value of lost load improvement expected. This resulted in approximately 500 of the 1,200 circuits on PSE&G's network being selected for sectionalizing through adding a recloser to split the circuit into two sections. Additionally, where it is feasible, PSE&G will add a tie recloser to the tail end of the circuit to provide an additional source to the circuit in the event of a long-term outage on the first circuit section or at the originating source station.
- Branch Reclosers: three-phase branch lines were evaluated to determine the value in installing branch reclosers on the worst performing branches from a customer interruption standpoint. These branch lines are protected with fuses that when blown require a service crew to be sent out to execute the repairs and return the line to service. PSE&G's criteria included that the branch lines serve at least 1,000 customers and that there was a value of lost load improvement expected. As a result, approximately 100 branches were put into the subprogram scope.
- Fuse Savers: all one- and two-phase branch lines fed from 4kV and 13kV circuits were analyzed to determine if adding a Fuse Saver (essentially a single-phase automatic recloser) was warranted.

PSE&G's criteria included that the branch serve at least 80 customers. The result of the evaluation determined that approximately 3,282 one and two-phase branches were included in the subprogram based on the value of lost load improvement expected.

In addition, PSE&G will continue to evaluate the selected circuits through the detailed design process to ensure that they continue to be appropriate for additional reclosers.

The work performed to date includes:

- Divisions performing detailed reviews of the proposed recloser locations;
- Divisions creating work packages;
- Relay Techs testing breakers and programming recloser controls;
- Divisions overhead crews installing poles, framing poles, and completing wire work in preparation of recloser installations; and
- All four Divisions have begun installing reclosers.

Table 10 – ES 2 Program Recloser Status as of March 31, 2020 provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year end targets and current status of engineering, installation, and commissioning.

Table 10 – ES 2 Program Recloser Status as of March 31, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)	Reclosers Installed	Reclosers Commissioned
13kV	800	549	333	0
4kV	179	163	24	0
Total	979	712	357	0

As shown in **Table 10**, with engineering comfortably ahead of construction, it allows PSE&G flexibility in selecting which projects to initiate construction and allows the subprogram progress to continue.

The IM evaluated PSE&G's equipment selection decision for the single and two-phase recloser devices that are being installed as part of the Contingency Reconfiguration subprogram. Initially, PSE&G identified two potential options for this equipment, the TripSaver-II manufactured by the S&C Electric Company and the Fusesaver manufactured by Siemens. After several meetings and conference calls to review and discuss PSE&G's requirements against the capabilities of this equipment, it was identified that the TripSaver-II lacked the capability to remotely communicate via supervisory control and data acquisition (SCADA), and thus did not meet PSE&G's requirement to have the equipment able to document and capture the momentary outages on the electric distribution system. Therefore, the Siemens Fusesaver device was selected as it was capable of meeting PSE&G's operating requirements.

The single-phase recloser device installation plan contemplates 2,307 single-phase and 980 two-phase devices over the course of the ES 2 Program. Pole locations and circuits have been verified for the installation of these devices, with individual maps of all fuse saver pole locations provided to the Divisions. Initially, PSE&G anticipated 112 single-phase and 40 two-phase devices as of the end of the first quarter of 2020, however installation of the fuse savers has been delayed due to the lack of radio availability and is now expected to commence in August 2020. The cause of the delay to radio availability was related to component supply delays and certification delays related to Covid-19. In the interim, PSE&G has adjusted its commissioning strategy and is installing additional reclosers to continue to

advance the subprogram. PSE&G expects the gap between installation and commissioning will be closed by the end of the year with no overall impact to the subprogram.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2020 are presented in **Table 11 – ES 2 Program Contingency Reconfiguration Costs as of March 31, 2020**.

Table 11 – ES 2 Program Contingency Reconfiguration Costs as of March 31, 2020

Scope & Division		Q4 2019	Q1 2020	Total	Forecast	% of Actuals to Forecast
		Actuals				
Reclosers	Central	$2,737,167	$3,918,150	$6,655,317	$27,309,897	24%
	Metro	$2,231,431	$3,576,616	$5,808,047	$23,547,928	25%
	Palisades	$2,515,569	$3,353,246	$5,868,815	$27,460,493	21%
	Southern	$2,081,220	$4,003,537	$6,084,758	$29,657,985	21%
Fuse Savers	Central	$9,970	$29,667	$39,637	$969,760	4%
	Metro	$7,557	$15,498	$23,055	$675,723	3%
	Palisades	$7,468	$15,259	$22,727	$9,245,276	0%
	Southern	$9,792	$21,458	$31,250	$629,503	5%
Total		**$9,609,966**	**$14,933,431**	**$24,533,604**	**$119,496,564**	**21%**

Findings & Observations:

- PSE&G has planned and reviewed resource and installation schedules with the Divisions to ensure they are appropriately prepared to execute the work required for this subprogram.
- Recloser installations advanced ahead of target through the end of the first quarter of 2020, and while radio delays affected the installation of fuse savers and commissioning of reclosers, PSE&G expects to close this gap by the end of 2020. Additionally, by having recloser engineering consistently ahead of the installation plan, it allows PSE&G flexibility in its schedule.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

The Grid Modernization – Communication System organization is led by Al Balletto (who also leads the other Grid Modernization subprogram) and is supported by communication system leads Jim Yorke (wireless network), Lukasz Kubas (SCADA commissioning), Bob Kirk (fiber – outside plant), and Ayoola Odeyemi (fiber – inside plant), with the latter two leads also a part of the Contingency Reconfiguration subprogram due to the interconnectedness of these subprograms.

The wireless network scope specifically calls for building a robust wireless network across PSE&G's service territory that will support real-time wireless connectivity to all operational asset and redundant communication paths to network devices. Additionally, the network will have robust monitoring and multilayered security, as well as being independent of commercial carriers. PSE&G received bids from multiple vendors for the wireless network, ultimately awarding to FirstNet based on its lower overall cost and better alignment with PSE&G's objectives than other bidders offered. The FirstNet broadband

network is built through a private-public partnership between AT&T and the U.S. Federal Government and provides wireless broadband to first responders on dedicated spectrum bands. The PSE&G devices communicating on this network will benefit from overlapping coverage from multiple tower sites and multiple layers of redundancy providing increased reliability.

It is expected that approximately 2,704 routers will be installed in existing reclosers to support the broadened wireless connectivity. Through the end of the first quarter of 2020, there were no retrofitted reclosers installed with activities primarily focused on planning (reviewing resource and installation schedules with the Divisions, completing installation and commissioning procedures, etc.). The recloser retrofitting installation plan is reflected in **Table 12 – ES 2 Program Retrofitting Reclosers Schedule** and contemplates most of the 2020 work occurring during the fourth quarter.

Table 12 – ES 2 Program Retrofitting Reclosers Schedule

Division	2020	2021	2022	2023	Total
Central	33	240	236	265	774
Metro	29	175	163	129	496
Palisades	26	180	182	198	586
Southern	44	284	267	253	848
Total	***132***	***879***	***848***	***845***	***2,704***

The IM evaluated PSE&G's vendor selection decision for the wireless equipment, specifically the routers, antennas, and related accessories and mounting equipment to establish SCADA communication, in addition to the supply, configuration, and implementation a network management system capable of managing the initial deployment of 7,900 routers (with the ability to scale up to over 500,000 end points in the future). Hardware from Sierra Wireless and Nokia represented the two options for the required equipment (from different vendors), with AT&T/Nokia being selected based on the technical solutions, and specifically the IT security requirements, better suiting the needs of PSE&G.

The fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. Execution of this scope is based on a full review of all proposed projects and routes with proposed route maps created and released to engineering to design and build work packages. Asset Strategy performed the first pass in prioritizing the fiber projects, assessing the communication status and the long-term status of the facilities to ensure they are a good fit for the subprogram. The Divisions then performed preliminary review of the fiber routes to identify any potential permitting requirements.

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2020 are presented in **Table 13 – ES 2 Program Grid Modernization – Communication System Costs as of March 31, 2020**.

Table 13 – ES 2 Program Grid Modernization – Communication System Costs as of March 31, 2020

Scope & Division		Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
		Actuals				
Retrofit Reclosers	Central	$0	$50,613	$50,613	$7,819,860	1%
	Metro	$0	$44,164	$44,164	$6,629,143	1%
	Palisades	$0	$44,164	$44,164	$6,854,198	1%
	Southern	$0	$46,901	$46,901	$8,313,084	1%
Fi be	Central	$1,691	$133,115	$134,806	$4,545,000	3%
	Metro	$1,457	$109,382	$110,839	$6,330,000	2%

	Palisades	$1,582	$194,451	$196,033	$3,300,000	6%
	Southern	$4,731	$65,721	$70,452	$2,490,000	3%
	Cutovers	$0	$0	$0	$6,735,000	0%
Wireless Network		$74,306	$1,525,801	$1,600,107	$12,063,705	13%
Total		**$83,767**	**$2,214,312**	**$2,298,078**	**$65,079,990**	**4%**

Findings & Observations:

- The IM finds that selection of FirstNet for the wireless broadband network services was an appropriate selection that will achieve PSE&G's intended objectives, including superior coverage and reliability, at a competitive cost.
- Primary activities to date relate to planning and procurement, including developing detailed schedules and installation and commissioning procedures with the Divisions.
- New reclosers (as Contingency Reconfiguration subprogram) have installation priority of retrofits due to new reclosers providing segregation to the sections they are installed that improves reliability (while retrofits improve communications on the devices).
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Stipulation identified the Grid Modernization – ADMS subprogram to include up to $35 million invested to develop an ADMS that will replace the existing Outage Management System (OMS). The ADMS will incorporate data from Geographic Information System (GIS) and SCADA, intelligent fault indicators, smart meters, and other advanced metering infrastructure (AMI). This will provide enhanced storm damage management including advanced estimated time of restoration calculations and provide AMI capabilities including automated restoration verification, smart detection of nested outages, and visualization of ping results.

The Grid Modernization – ADMS organization is led by Al Balletto (as mentioned above, Mr. Balletto also leads the other Grid Modernization subprogram) and is supported by ADMS leads Steve Zinser (OMS), Francis Frank (Distributed Management System (DMS)/ Distributed Energy Resource Management System (DERMS)), and Ryan Wilson (ADMS platform), as well as Dan Thomsen (Senior Principal Technology Product Consultant) and Mary Jane Jacobson (Performance Measurement Analyst).

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, with scopes of work developed in the first quarter of 2020. The ADMS is currently forecasted to go live during the second quarter of 2022. The high-level schedule was based on hardware milestones and a goal of getting the equipment in place prior to the summer outage period in 2023. Currently, working with the vendors to incorporate more detail into the subprogram schedule.

The IM evaluated PSE&G's vendor selection decision for the ADMS, which was a sole source award to Open Systems International Inc. (OSII). The sole source decision was based on OSII being the vendor for the SCADA component of the ADMS, utilizing proprietary software of OSII, in addition to the supporting vendor for the operations technology platform. Because there is no other vendor capable of performing these services, it was reasonable and appropriate to award this scope of work to OSII.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2020 are presented in **Table 14 – ES 2 Program Grid Modernization – ADMS Costs as of March 31, 2020**.

Table 14 – ES 2 Program Grid Modernization – ADMS Costs as of March 31, 2020

Q4 2019	Q1 2020	Total	Forecast	% of Actuals to Estimate
Actuals				
$36,213	$925,689	$961,902	$40,375,128	2%

Findings & Observations:

- The primary activities to date on the subprogram are primarily planning activities, including having workshops with the software vendor and operations and finalizing the scope of work.
- Selection of OSII as a vendor through a sole source award was reasonable and appropriate given OSII's unique capabilities in providing the required services.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric life cycle subprograms described in the original ES 2 Program filing. The preliminary planning by PSE&G estimates that approximately one-third of the Stipulated Base funds will be used towards the electric life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards.

The outside plan higher design and construction standards scope of work contemplates replacing the traditional open wire and cross-arm type construction on distribution overheard circuits with spacer cable in targeted locations. PSE&G determined that spacer cable provides significant improvement in customer reliability during storm events and other tree-related events as compared to the traditional methods. At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. The final circuit selection for this effort is still being developed but will be selected from PSE&G's original proposal using historical value of lost load from reportable and major event history.

Through the first quarter of 2020, there was no spend in the electric stipulated base projects as the projects are still being identified, planned, and going through the approval process. Four stations have been identified for life cycle station upgrades and are expected to go before the URB in June 2020 for approval.

Findings & Observations:

- The electric stipulated base projects remain in the planning and approval phases, as such the IM has no additional comments on this component of the ES 2 Program at this time.

F. Gas M&R Station Upgrades

The Stipulation identified that the Gas M&R subprogram will consist of up to $50.5 million in investments through the ES 2 Program Accelerated Rate Recovery Mechanism to rebuild/modernize six gas M&R stations. An additional $50.5 million will be invested through Stipulated Base to be recovered

in PSE&G's next base rate case, bringing the total subprogram investment to $101 million. While the current estimates forecast the six identified M&R stations will utilize the full $101 million investment, an additional stipulated base project (Hillsborough M&R) was identified if the total cost of the subprogram comes in under the stipulated amount.

The Gas M&R subprogram is led by Charlie Miracola, with two senior project managers splitting five of the projects (Camden, Mt. Laurel, Westampton, East Rutherford, and Paramus) and a project manager overseeing the other project (Central). The subprogram is also supported by Sonia Zacher-Martini (PMO Manager), Tony Fuhrman (Manager Gas Asset Strategy), and John Fillman (Manager M&R).

The common scope of work at all stations in the Gas M&R subprogram is for installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. As part of the planning efforts, PSE&G's Asset Management group evaluated the equipment at each station, including performing inspections, examining O&M records, and receiving feedback from the operations personnel to determine the possibility for re-using equipment rather than replacing it. Additional scope elements for each of the specific stations is described in the following subsections on the individual stations.

The IM evaluated PSE&G's selection of the design work for the Mt. Laurel and Westampton projects, which were the first to be awarded in the Gas M&R subprogram. The evaluation included both technical and commercial components, with both projects ultimately awarded to the highest evaluated contractor with the requisite experience and capabilities, which in these cases was also the lowest price bidder. The Camden design work was also initially awarded in this period, but due to the selected contractor not agreeing to the procurement terms and conditions, the work was re-bid, with the Camden design work and the other remaining projects having design contracts awarded in May-June 2020.

Through the end of the first quarter, preliminary design had been initiated on each of the Gas M&R stations. Additionally, the contract design RFP for each station was issued, with recommendations to award completed for the Westampton, Camden, and Mt. Laurel stations. The remaining stations are expected to have recommendations to award for the design services early in the second quarter of 2020. As with other subprograms in the ES 2 Program, the primary Covid-19 related impact has been shifting in-person meetings to a virtual setting. The detailed project schedules are currently under development.

Table 15 – ES 2 Program Gas M&R Summary Status as of March 31, 2020 below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 15**, there has been minimal spend to date on the subprogram, primarily related to initial planning efforts.

Table 15 – ES 2 Program Gas M&R Summary Status as of March 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$60,017	0%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$51,917	0%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$46,757	0%	Jan 2023

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals	% of Actuals to Estimate	Forecasted In-Service
4. Mount Laurel	Office	$11,300,000	$6,100,000	$17,400,000	$33,769	0%	Jan 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$46,634	0%	Jul 2023
6. Westampton	Office	$8,300,000	$4,400,000	$12,700,000	$49,234	0%	Jul 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$288,328**	**0%**	**Jul 2023**
**-Included in the Stipulated Base.*							

Findings & Observations:

- The primary efforts to date on the subprogram are initial planning efforts, including the preparation of bid material and awarding of bids for the design services on the projects (with two awarded in the first quarter of 2020 and the remaining awarded in the second quarter of 2020).
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

The Camden M&R station scope includes construction of a new station to support buildings and critical equipment being installed one foot above the flood elevation level. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract (in June 2020), and other planning activities. The actual spend by quarter for the Camden project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$13,326	$46,691	$60,017	$15,400,000	0%

2. Central

The Central M&R station scope includes consolidating the three existing stations at this site into a new building. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Central project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$6,869	$45,048	$51,917	$19,700,000	0%

3. East Rutherford

The East Rutherford M&R station scope includes construction of a new station to support buildings and critical equipment being installed one foot above the flood elevation level. The major equipment at this station that is not near the end of life condition and operationally can be relocated will be re-installed to the appropriate elevation at the new station.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the East Rutherford project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$9,010	$37,747	$46,757	$15,900,000	0%

4. Mount Laurel

The Mount Laurel M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Mount Laurel project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$5,965	$27,804	$33,769	$17,400,000	0%

5. Paramus

The Paramus M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Paramus project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$8,842	$37,793	$46,634	$19,900,000	0%

6. Westampton

The Westampton M&R station scope includes installation of new underground piping that is rated for the full pipeline company maximum allowable operating pressure, thus eliminating the need for high pressure relief valves and enhancing safety and environmental performance. Overpressure protection will be provided through series regulators with a working regulator and monitor regulator. Downstream distribution system relief valves will also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. The major equipment at this station that is not near the end of life condition and operationally can remain in service will not be replaced.

As noted above, the primary work to date on the Gas M&R subprogram has been commencing preliminary engineering, awarding of the A/E contract, and other planning activities. The actual spend by quarter for the Westampton project as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Total	Estimate	% of Actuals to Estimate
Actuals				
$8,395	$40,839	$49,234	$12,700,000	0%

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2020 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

18 SEPTEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Appendix A – Draft Report Comments and Responses

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	Has the Company identified comparable projects base spend projects for both electric and gas?	The IM scope includes the Energy Strong 2 Program Accelerated Rate Recovery investments (the core ES 2 Program) and the Stipulated Base expenditures. The Baseline capital expenditures are outside the IM scope.	No change
RCR-INF-2	Comment: Table 2 Total Estimate should be labeled to either reflect current estimate or Stipulated amount just to clarify distinction. For example, new Academy and State Street substation estimates are not incorporated in Table 9 as well.	Both Table 2 and Table 9 reflect the current approved estimates as of the end of the first quarter of 2020. At that time, the new Academy and State Street estimates had not gone through the formal estimate approval process as the approval of the mitigation change was still pending.	No change
RCR-INF-3	Page 6, are there updates to the two projects (Academy and State)?	The IM will continue to provide updates on the Academy and State Street projects in future reports as new information is received.	No change
RCR-INF-4	Page 7, for the following substations (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley), is the A/E firm conducting the Transmission component (upgrade from 26 to 69 kV) also conducting the Energy Strong 2 A/E work?	Yes, those projects have the same A/E for the ES 2 Program and Transmission components, with the exception of State Street where PSE&G is performing the ES 2 Program A/E work.	No change
RCR-INF-5	What are the three firms selected to do the A/E work?	Black & Veatch and Burns & McDonnell have currently been assigned to Electric Station Flood Mitigation projects (based on their associated 69kV work); additionally Black & Veatch, Sargent & Lundy, and Mesa Associates were approved through the competitive bid process and may be awarded work on other projects as it is released.	Future reports will call out the A/E on each project
RCR-INF-6	Page 7, do any of the remaining seven substations have any transmission upgrade work associated? If so, which ones?	No	No change
RCR-INF-7	Page 8, please identify which stations that are not in-house and not associated with the 69kV transmission upgrade would be competitively bid for A/E services.	The 69kV-associated projects and those that were not assigned to PSE&G internal resources were all competitively bid.	No change
RCR-INF-8	With reference to Page 9, how much experience with ES 1 is there with the listed PSEG personnel and Pegasus personnel.	During the ES 1 Program, the IM interfaced with each of the individuals listed as providing overall	No change

ID #	Question/Comment	IM Response	Report Changes
		direction and oversight on the ES 2 Program except for Danny Nembhard.	
RCR-INF-9	Comment on pages 10 through 12, what is the significance of bracketed substation associated with each heading?	As indicated on page 10, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed by the IM.	No change
RCR-INF-10	Page 10, is the feasibility/turnover stage the same as the office level estimate presented in Table 9?	Yes.	Clarified in **Section II.C.2.**
RCR-INF-11	Page 13, are there current plans to perform a project audit similar to what was conducted in ES 1?	Yes, initial conversations with PSEG's Internal Audit group have indicated an audit on the Program is expected to commence early in 2021. The IM will continue to provide updates on the audit status as new information is confirmed.	No change
RCR-INF-12	Page 18, the five-year baseline level estimate would exclude Superstorm Sandy. Presumably, this should not be an issue since these stations and feeders were not damaged in Superstorm Sandy.	The five-year baseline circuit performance was intended to help establish how the current/future circuit performance can be evaluated.	No change
RCR-INF-13	Page 19, please describe how the ES 2 planning is more integrated than ES 1 and what role planning plays in the process.	On the ES 2 Program there was centralized work planning and scheduling, including a more thorough stakeholder review process (based on more robust front-end planning and design). Enhanced planning typically results in the ability to better plan and forecast work, including reducing the likelihood of unexpected issues being identified later in the process.	Added information to **Section III.A.**
RCR-INF-14	Table 8, with the scope locked, have the Company's estimates changed for the five substations, excluding Academy and State.	Each would be expected to change as the projects continue to work through detailed engineering at the different estimate phases. The locking of the scope is part of the design process that is an input to the estimating process.	No change
RCR-INF-15	Page 21, is the switchgear vendor selection process different for ES 2 than ES 1?	Same switchgear vendor selection process for the ES 1 and the ES 2 Programs– full bid event with a commercial and technical review, followed by award.	Added information to **Section III.A.**
RCR-INF-16	Page 28, do the current estimate of $30 million for the Market Street substation include cost of environmental liabilities? Was most of the $2.1 million spent for environmental cleanup?	The estimated costs for the environmental contaminated soil issue is $2.3 million and is included in the $30 million estimate. The $2.3	Added information to

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td>million includes the cost of excavation for installation of poles on the outside plant scope and certified contractor testing, sampling, soil removal, and Sonotube installations.</td><td>Section III.A.8.</td></tr>
<tr><td>RCR-INF-17</td><td>Pages 22 thru 35 provides a station-by-station summary of upcoming activities at each station. A table showing a list of all upcoming station activities listed by station rather than activity along with a note of any activities that were carried over from the prior quarter would help identify potential bottle necks in the project schedule. An example table is shown below.
<table>
<tr><th>Station</th><th>Upcoming Activity</th><th>Carry Over from Prior Q</th></tr>
<tr><td>Academy St.</td><td>Commencement of detailed design and civil, demolition, and electrical drawings issued for review.</td><td>None</td></tr>
<tr><td>Clay St.</td><td>Lock the scope and commence design on the licensing and permitting package</td><td>Lock scope</td></tr>
<tr><td>Hasbrouck Heights</td><td>Prepare and issue the licensing and permitting package and commence detailed engineering design</td><td>None</td></tr>
<tr><td>Constable Hook</td><td>In the initial planning and origination stages</td><td>In initial stages</td></tr>
</table></td><td>The IM will incorporate this concept into the 2020 Q2 report.</td><td>Will incorporate into future reports</td></tr>
<tr><td>RCR-INF-18</td><td>Page 36, what is the selection criteria for the contingency reconfiguration projects? Is there a copy available? What is the Company’s definition of customer impacts and how are they being prioritized?</td><td>Specific criteria was developed for the 13kV circuits, 4kV circuits, branch reclosers, and fuse savers. Additionally, the selected circuits go through continued evaluation as detailed design efforts proceed to ensure they remain an appropriate selection.</td><td>Additional detail in Section III.B.</td></tr>
<tr><td>RCR-INF-19</td><td>Were TripSaver-II installed as part of ES 1? Is there a cost differential between the TripSaver II and Fusesaver devices?</td><td>TripSaver II did not meet technical requirements so cost was not a factor in the decision. These devices are relatively new devices and were not installed as part of the ES 1 Program.</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-20	Page 36, please elaborate on the lack of radio availability.	The radio availability was impacted by certification and component supply delays related to Covid-19. This has now been resolved.	Added additional detail in **Section III.B.**
RCR-INF-21	Page 37, is the installed communication system compatible with current and future systems? Would the system be compatible with an AMI system if the BPU were to approve AMI?	The wireless network will provide real-time wireless connectivity to all operational assets and redundant communication paths to network devices.	No change
RCR-INF-22	Page 38, is the 500,000 endpoint the current limit to the installed communications system?	As noted, the initial deployment is for 7,900 routers with the ability to scale up to over 500,000 end points in the future.	No change
RCR-INF-23	Page 39, was the ADMS vendor selection competitively bid? Is OSII a current vendor for PSEG?	As noted, the ADMS vendor selection was a sole source award to OSII base on OSII being the existing vendor for the SCADA component of AMDS, which utilizes a proprietary software of OSII, in addition to being the supporting vendor for the operations technology platform.	No change
S-INF-1	As noted in the report, the Grid Modernization – ADMS subprogram is now forecasted to cost approximately $40 million (See Page 1, Table 1) – over its original budget of $35 million. What does the Company attribute to this cost increase, and is it related to the Company's decision to select a sole-source vendor for the ADMS? (See Page 39).	The primary variances between the initial forecast (done at the time of the ES 2 Program filing) and the current forecast (at the 70% estimate level) is related to increased levels of vendor support needed to address additional complexities identified in the application landscape (primarily related to integration of new and/or upgraded PSE&G operational technology platforms) and additional hardware (e.g. servers) required after a review of the system identified the significant growth in the number of distribution assets on the network since the time of the filing.	Added additional detail in **Section III.D.**
S-INF-2	**Contingency Reconfiguration Subprogram - COR Charges** a. Please provide additional details about the work comprising the cost of removal charges (See Page 16, Table 5) within the Contingency Reconfiguration subprogram. b. In regard to the statement "Contingency Reconfiguration COR charges reflect work on the recloser replacement efforts in all districts", is the Company replacing existing reclosers in order to facilitate the subprogram?	(a) COR charges reflect removal of existing infrastructure to install new reclosers in all districts. (b) No existing reclosers are being replaced; in some case existing reclosers are being reprogrammed as a SCADA Switch Inline in	No change

ID #	Question/Comment	IM Response	Report Changes
		instances where two reclosers are installed to balance a circuit into three sections.	
S-INF-3	Please describe any other factors (besides SCADA) considered by the Company when choosing between TripSaver-II reclosers and Fusesaver reclosers. Please indicate if the TripSaver-II reclosers have any capabilities that are not possessed by the Fusesaver reclosers selected by the Company.	Remote communications via SCADA is an operational requirement for PSE&G, this was the primary driver.	No change
S-INF-4	In regard to the Grid Modernization – Communications System subprogram, the report states that AT&T/Nokia hardware was selected over Sierra Wireless based on the technical solutions better suiting the needs of PSE&G. (See Page 38). a. Please provide additional details about these technical solutions that better suit the needs of PSE&G. b. Please describe any other factors considered by the Company, including costs, when selecting a vendor.	(a) PSE&G completed a detailed IT security architecture requirements review of both vendors and found the responses from Sierra Wireless were not in compliance with the IT security requirements of PSE&G. (b) Non-technical factors feature cost as a primary factor, typically broken out into key components for evaluation purposes; other factors include related work a vendor may have (simplifies coordination efforts compared to multiple vendors, lowers execution risk and cost).	Added additional detail in **Section III.C.**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2020 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

18 SEPTEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Appendix A – Draft Report Comments and Responses

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	Has the Company identified comparable projects base spend projects for both electric and gas?	The IM scope includes the Energy Strong 2 Program Accelerated Rate Recovery investments (the core ES 2 Program) and the Stipulated Base expenditures. The Baseline capital expenditures are outside the IM scope.	No change
RCR-INF-2	Comment: Table 2 Total Estimate should be labeled to either reflect current estimate or Stipulated amount just to clarify distinction. For example, new Academy and State Street substation estimates are not incorporated in Table 9 as well.	Both Table 2 and Table 9 reflect the current approved estimates as of the end of the first quarter of 2020. At that time, the new Academy and State Street estimates had not gone through the formal estimate approval process as the approval of the mitigation change was still pending.	No change
RCR-INF-3	Page 6, are there updates to the two projects (Academy and State)?	The IM will continue to provide updates on the Academy and State Street projects in future reports as new information is received.	No change
RCR-INF-4	Page 7, for the following substations (Woodlynne, State Street, Academy Street, Clay Street, Hasbrouck Heights, Meadow Road, Lakeside Avenue, Toney's Brook, and Orange Valley), is the A/E firm conducting the Transmission component (upgrade from 26 to 69 kV) also conducting the Energy Strong 2 A/E work?	Yes, those projects have the same A/E for the ES 2 Program and Transmission components, with the exception of State Street where PSE&G is performing the ES 2 Program A/E work.	No change
RCR-INF-5	What are the three firms selected to do the A/E work?	Black & Veatch and Burns & McDonnell have currently been assigned to Electric Station Flood Mitigation projects (based on their associated 69kV work); additionally Black & Veatch, Sargent & Lundy, and Mesa Associates were approved through the competitive bid process and may be awarded work on other projects as it is released.	Future reports will call out the A/E on each project
RCR-INF-6	Page 7, do any of the remaining seven substations have any transmission upgrade work associated? If so, which ones?	No	No change
RCR-INF-7	Page 8, please identify which stations that are not in-house and not associated with the 69kV transmission upgrade would be competitively bid for A/E services.	The 69kV-associated projects and those that were not assigned to PSE&G internal resources were all competitively bid.	No change
RCR-INF-8	With reference to Page 9, how much experience with ES 1 is there with the listed PSEG personnel and Pegasus personnel.	During the ES 1 Program, the IM interfaced with each of the individuals listed as providing overall	No change

ID #	Question/Comment	IM Response	Report Changes
		direction and oversight on the ES 2 Program except for Danny Nembhard.	
RCR-INF-9	Comment on pages 10 through 12, what is the significance of bracketed substation associated with each heading?	As indicated on page 10, the brackets next to the procedure name identify the specific project where the implementation of the procedure was reviewed and discussed by the IM.	No change
RCR-INF-10	Page 10, is the feasibility/turnover stage the same as the office level estimate presented in Table 9?	Yes.	Clarified in **Section II.C.2.**
RCR-INF-11	Page 13, are there current plans to perform a project audit similar to what was conducted in ES 1?	Yes, initial conversations with PSEG's Internal Audit group have indicated an audit on the Program is expected to commence early in 2021. The IM will continue to provide updates on the audit status as new information is confirmed.	No change
RCR-INF-12	Page 18, the five-year baseline level estimate would exclude Superstorm Sandy. Presumably, this should not be an issue since these stations and feeders were not damaged in Superstorm Sandy.	The five-year baseline circuit performance was intended to help establish how the current/future circuit performance can be evaluated.	No change
RCR-INF-13	Page 19, please describe how the ES 2 planning is more integrated than ES 1 and what role planning plays in the process.	On the ES 2 Program there was centralized work planning and scheduling, including a more thorough stakeholder review process (based on more robust front-end planning and design). Enhanced planning typically results in the ability to better plan and forecast work, including reducing the likelihood of unexpected issues being identified later in the process.	Added information to **Section III.A.**
RCR-INF-14	Table 8, with the scope locked, have the Company's estimates changed for the five substations, excluding Academy and State.	Each would be expected to change as the projects continue to work through detailed engineering at the different estimate phases. The locking of the scope is part of the design process that is an input to the estimating process.	No change
RCR-INF-15	Page 21, is the switchgear vendor selection process different for ES 2 than ES 1?	Same switchgear vendor selection process for the ES 1 and the ES 2 Programs– full bid event with a commercial and technical review, followed by award.	Added information to **Section III.A.**
RCR-INF-16	Page 28, do the current estimate of $30 million for the Market Street substation include cost of environmental liabilities? Was most of the $2.1 million spent for environmental cleanup?	The estimated costs for the environmental contaminated soil issue is $2.3 million and is included in the $30 million estimate. The $2.3	Added information to

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td>million includes the cost of excavation for installation of poles on the outside plant scope and certified contractor testing, sampling, soil removal, and Sonotube installations.</td><td>Section III.A.8.</td></tr>
<tr><td>RCR-INF-17</td><td>Pages 22 thru 35 provides a station-by-station summary of upcoming activities at each station. A table showing a list of all upcoming station activities listed by station rather than activity along with a note of any activities that were carried over from the prior quarter would help identify potential bottle necks in the project schedule. An example table is shown below.
<table>
<tr><th>Station</th><th>Upcoming Activity</th><th>Carry Over from Prior Q</th></tr>
<tr><td>Academy St.</td><td>Commencement of detailed design and civil, demolition, and electrical drawings issued for review.</td><td>None</td></tr>
<tr><td>Clay St.</td><td>Lock the scope and commence design on the licensing and permitting package</td><td>Lock scope</td></tr>
<tr><td>Hasbrouck Heights</td><td>Prepare and issue the licensing and permitting package and commence detailed engineering design</td><td>None</td></tr>
<tr><td>Constable Hook</td><td>In the initial planning and origination stages</td><td>In initial stages</td></tr>
</table></td><td>The IM will incorporate this concept into the 2020 Q2 report.</td><td>Will incorporate into future reports</td></tr>
<tr><td>RCR-INF-18</td><td>Page 36, what is the selection criteria for the contingency reconfiguration projects? Is there a copy available? What is the Company’s definition of customer impacts and how are they being prioritized?</td><td>Specific criteria was developed for the 13kV circuits, 4kV circuits, branch reclosers, and fuse savers. Additionally, the selected circuits go through continued evaluation as detailed design efforts proceed to ensure they remain an appropriate selection.</td><td>Additional detail in Section III.B.</td></tr>
<tr><td>RCR-INF-19</td><td>Were TripSaver-II installed as part of ES 1? Is there a cost differential between the TripSaver II and Fusesaver devices?</td><td>TripSaver II did not meet technical requirements so cost was not a factor in the decision. These devices are relatively new devices and were not installed as part of the ES 1 Program.</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-20	Page 36, please elaborate on the lack of radio availability.	The radio availability was impacted by certification and component supply delays related to Covid-19. This has now been resolved.	Added additional detail in **Section III.B.**
RCR-INF-21	Page 37, is the installed communication system compatible with current and future systems? Would the system be compatible with an AMI system if the BPU were to approve AMI?	The wireless network will provide real-time wireless connectivity to all operational assets and redundant communication paths to network devices.	No change
RCR-INF-22	Page 38, is the 500,000 endpoint the current limit to the installed communications system?	As noted, the initial deployment is for 7,900 routers with the ability to scale up to over 500,000 end points in the future.	No change
RCR-INF-23	Page 39, was the ADMS vendor selection competitively bid? Is OSII a current vendor for PSEG?	As noted, the ADMS vendor selection was a sole source award to OSII base on OSII being the existing vendor for the SCADA component of AMDS, which utilizes a proprietary software of OSII, in addition to being the supporting vendor for the operations technology platform.	No change
S-INF-1	As noted in the report, the Grid Modernization – ADMS subprogram is now forecasted to cost approximately $40 million (See Page 1, Table 1) – over its original budget of $35 million. What does the Company attribute to this cost increase, and is it related to the Company's decision to select a sole-source vendor for the ADMS? (See Page 39).	The primary variances between the initial forecast (done at the time of the ES 2 Program filing) and the current forecast (at the 70% estimate level) is related to increased levels of vendor support needed to address additional complexities identified in the application landscape (primarily related to integration of new and/or upgraded PSE&G operational technology platforms) and additional hardware (e.g. servers) required after a review of the system identified the significant growth in the number of distribution assets on the network since the time of the filing.	Added additional detail in **Section III.D.**
S-INF-2	**Contingency Reconfiguration Subprogram - COR Charges** a. Please provide additional details about the work comprising the cost of removal charges (See Page 16, Table 5) within the Contingency Reconfiguration subprogram. b. In regard to the statement "Contingency Reconfiguration COR charges reflect work on the recloser replacement efforts in all districts", is the Company replacing existing reclosers in order to facilitate the subprogram?	(a) COR charges reflect removal of existing infrastructure to install new reclosers in all districts. (b) No existing reclosers are being replaced; in some case existing reclosers are being reprogrammed as a SCADA Switch Inline in	No change

ID #	Question/Comment	IM Response	Report Changes
		instances where two reclosers are installed to balance a circuit into three sections.	
S-INF-3	Please describe any other factors (besides SCADA) considered by the Company when choosing between TripSaver-II reclosers and Fusesaver reclosers. Please indicate if the TripSaver-II reclosers have any capabilities that are not possessed by the Fusesaver reclosers selected by the Company.	Remote communications via SCADA is an operational requirement for PSE&G, this was the primary driver.	No change
S-INF-4	In regard to the Grid Modernization – Communications System subprogram, the report states that AT&T/Nokia hardware was selected over Sierra Wireless based on the technical solutions better suiting the needs of PSE&G. (See Page 38). a. Please provide additional details about these technical solutions that better suit the needs of PSE&G. b. Please describe any other factors considered by the Company, including costs, when selecting a vendor.	(a) PSE&G completed a detailed IT security architecture requirements review of both vendors and found the responses from Sierra Wireless were not in compliance with the IT security requirements of PSE&G. (b) Non-technical factors feature cost as a primary factor, typically broken out into key components for evaluation purposes; other factors include related work a vendor may have (simplifies coordination efforts compared to multiple vendors, lowers execution risk and cost).	Added additional detail in **Section III.C.**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
CORRECTED 2020 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Key Decisions 3
B. Program Management 4
C. Cost Assignments 4
D. System Performance 9
III. Project Status 2
A. Electric Station Flood Mitigation 2
B. Contingency Reconfiguration 10
C. Grid Modernization – Communication System 12
D. Grid Modernization – ADMS 13
E. Electric Stipulated Base 13
F. Gas M&R Station Upgrades 16

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems	ADMS
Allowance for Funds Used During Construction	AFUDC
Architectural and Engineering	A/E
Board of Public Utilities	BPU
Chief Financial Officer	CFO
Construction Work In Progress	CWIP
Costs of Removal	COR
Distribution Management System	DMS
Distributed Energy Resource Management System	DERMS
Energy Strong 2	ES 2
Gas Metering & Regulating	Gas M&R
Independent Monitor	IM
Issued for Construction	IFC
Issued for Review	IFR
Open Systems International Inc.	OSII
Outage Management System	OMS
Potential Transformer	PT
Projects & Construction	P&C
Public Service Electric & Gas	PSE&G
Public Service Enterprise Group	PSEG
PSEG Internal Audit	PSEGIA
Record of Decision	ROD
Risk and Contingency	R&C
Utility Review Board	URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019 with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station lifecycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the second quarter of 2020, the bulk of the work within the ES 2 Program continued to be in the two largest subprograms, Electric Station Flood Mitigation with three projects now in construction and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers. Within the other subprograms, the two Grid Modernization subprograms continued to advance with the Communications piece primarily focusing on readying the new network and preparing for the selected fiber projects and the ADMS piece continuing to plan and scope the platform and necessary hardware equipment, while the Gas M&R subprogram largely remains in preliminary planning and early engineering activities. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020

Subprogram	2019 Spend	Q1 2020 Spend	Q2 2020 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$1,977,398	$5,118,886	$10,325,107	$17,421,391	$332,662,596	5%	Dec 2023	$389M
Contingency Reconfiguration	$9,600,174	$14,933,431	$8,662,536	$33,196,141	$150,876,803	22%	Jul 2023	$145M
Grid Modernization – Communications	$83,766	$2,214,312	$4,159,420	$6,457,497	$64,863,452	10%	Dec 2023	$72M
Grid Modernization – ADMS	$36,213	$925,689	$4,430,542	$5,392,444	$39,707,462	14%	Oct 2022	$35M
Electric Stipulated Base	$0	$0	$0	$0	$100,000,000	N/A	Under Development	$100M
Gas M&R Station Upgrades^	$52,406	$235,922	$651,513	$939,841	$65,600,000	1%	Jul 2023	$110M
Total*	$11,749,957	$23,428,239	$28,229,119	$63,407,315	$746,975,315	8%	Dec 2023	$851M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 17** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

As shown in **Table 1**, the Electric Stipulated Base component remained largely in the planning stage as of the end of the second quarter of 2020. However, the four stations comprising the lifecycle upgrades

portion of the Electric Stipulated Base were approved at a Study level estimate in a Utility Review Board (URB) meeting in June 2020 with a total current estimate of $79.7 million.[1] Additionally, the Contingency Reconfiguration subprogram saw its forecast increase from $119.5 million at the end of the first quarter of 2020 to $150.9 million at the end of the second quarter of 2020 as the Fuse Saver scope was fully forecasted during this quarter. It is expected that the forecast will continue to fluctuate as the scope is refined. Similarly, the forecasted completion date for the Grid Modernization – ADMS subprogram advanced from December 2023 as of the end of the first quarter of 2020 to October 2022 as of the end of the second quarter. This advancement was driven by additional schedule detail and development from what the high-level milestone schedule in place during the first quarter.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$17,000,000	$650,226	4%	10/25/2021
2. Clay Street	$42,000,000	$619,335	1%	12/27/2022
3. Constable Hook	$5,300,000	$101,960	2%	TBD
4. Hasbrouck Heights	$18,000,000	$531,773	3%	11/18/2022
5. Kingsland	$10,000,000	$255,665	3%	10/4/2023
6. Lakeside Avenue	$36,100,000	$442,176	1%	TBD
7. Leonia	$32,200,000	$713,897	2%	11/30/2022
8. Market Street	$30,000,000	$7,334,176	24%	9/22/2021
9. Meadow Road	$9,000,000	$310,637	3%	9/21/2023
10. Orange Valley	$26,600,000	$294,300	1%	TBD
11. Ridgefield 13kV	$25,500,000	$1,023,746	4%	10/19/2022
12. Ridgefield 4kV	$21,100,000	$2,971,169	14%	6/30/2021
13. State Street	$28,600,000	$378,656	1%	9/23/2023
14. Toney's Brook	$19,700,000	$414,002	2%	4/21/2023
15. Waverly	$35,400,000	$814,790	2%	12/4/2023
16. Woodlynne	$19,400,000	$564,882	3%	9/26/2023
**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*				

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects continue to have the highest percentage of spend, which is reflective of these two projects advancing further into construction. Additionally, three of the stations (Academy Street, Kingsland, and State Street) had internally approved new estimates at the end of June 2020 that went to approval before the URB in July 2020 and as such will be reported in the 2020 third quarter Independent Monitor (IM) report.

While early in the subprogram, the IM has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On November 16, 2020, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and, rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Second Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*

There were no formal RODs issued during the second quarter of 2020, however, PSE&G has proposed mitigation method changes driven by transmission project upgrade needs at three additional substations in the Electric Station Flood Mitigation subprogram, these are the Lakeside Avenue, Orange Valley, and Constable Hook substations. The IM is still in discussion with PSE&G with respect to these proposed mitigation methods and has not yet completed its evaluation, which will be discussed in the IM's next quarterly report.

The IM will continue to monitor the status of these proposed changes and include additional discussions on these projects as new information is available.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Costs of Removal as of June 30, 2020 below itemizes the charges to COR for the second and first quarters of 2020, the fourth quarter of 2019 and total ES 2 COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through June 30, 2020.

Table 4 – ES 2 Costs of Removal as of June 30, 2020

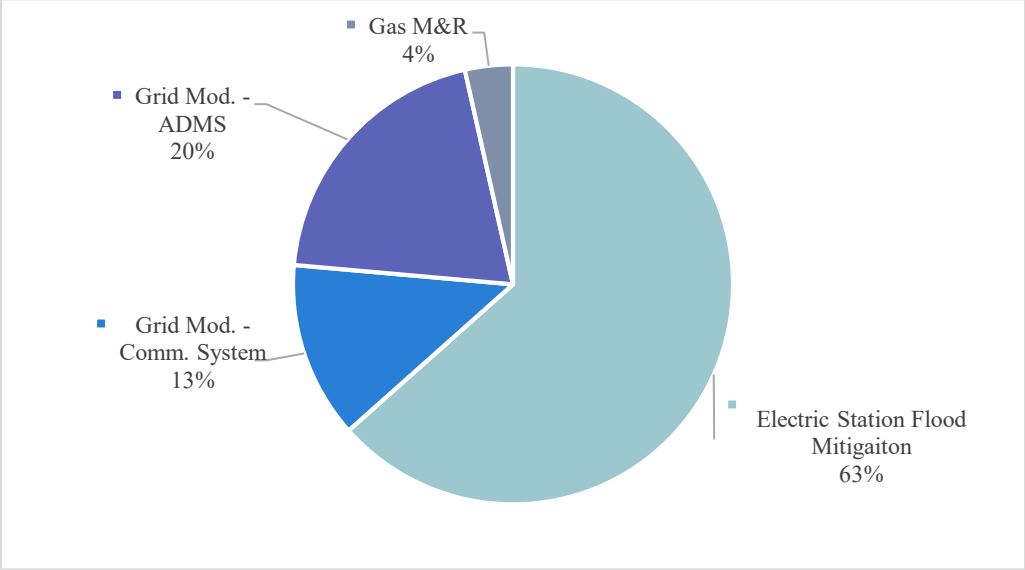
Subprogram	Q4 2019 COR	Q1 2020 COR	Q2 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$468,989**	**$536,321**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$624,595**	**$1,672,377**
Grid Modernization – Communications	**$0**	**$0**	**$1,495**	**$1,495**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,095,079**	**$2,210,193**

For the second quarter of 2020, the increase in COR charges is attributed to the removal of poles, insulators and transformers at Ridgefield and Market Street for the conversion of the 4kV circuits to 13kV. Contingency Reconfiguration COR charges reflect continued work involving removal of pole fixtures and conductors for the installation of new reclosers.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

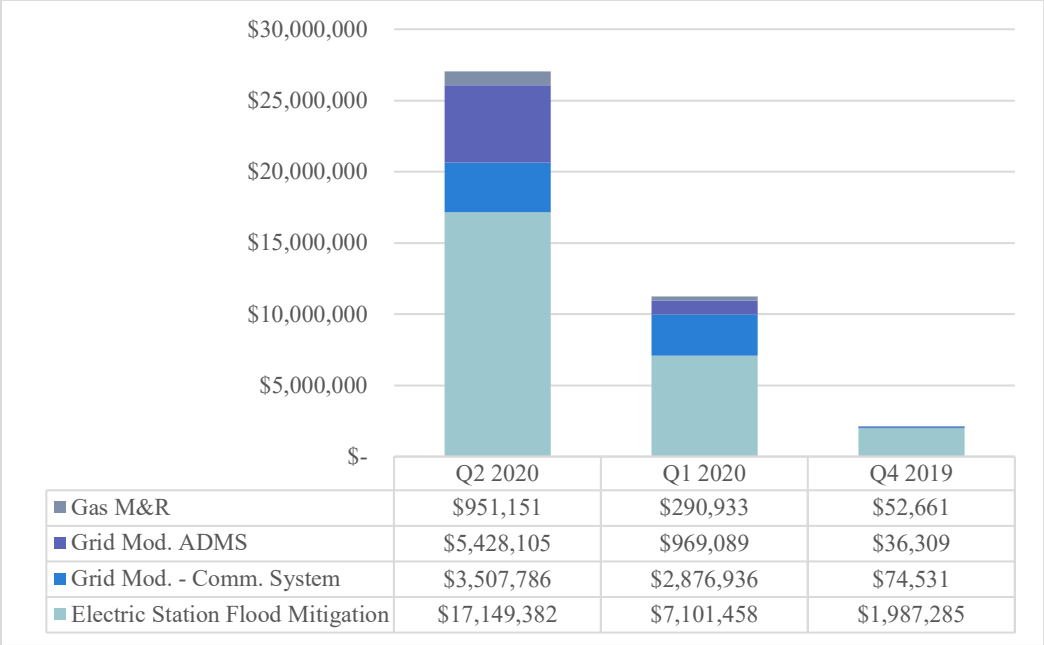
As of June 30, 2020, the Energy Strong CWIP balance was $27.0 million, compared to $10.3 million as of March 30, 2020. The largest components of June 30, 2020 CWIP were the elimination and conversion of the 4kV circuits at Market Street and Ridgefield substations, and work associated with the Advanced Distribution and Management System. The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2020** below.

Figure 1 – ES 2 CWIP as of June 30, 2020



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second and first quarters of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2020



Transfers from CWIP to plant in service have totaled $1.8 million as of June 30, 2020, which was comprised of Grid Modernization computer hardware. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. The changes to CWIP from the first quarter to the second quarter of 2020 are shown in **Table 5 – ES 2 CWIP Q1 to Q2 2020**.

Table 5 – ES 2 CWIP Q1 to Q2 2020

	Electric Station Flood Mitigation	Grid Modernization – Communication System	Grid Modernization – ADMS	Gas M&R
CWIP Balance as of Q1 2020	$7,101,458	$1,907,846	$969,089	$290,933
CWIP Additions during Q2 2020	$10,047,924	$3,427,230	$4,459,016	$660,218
CWIP Transfers to Plant In-Service during Q2 2020	$0	$1,827,290	$0	$0
CWIP Balance as of Q2 2020	$17,149,382	$3,507,786	$5,428,105	$951,151

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the second and first quarters of 2020, the fourth quarter of 2019, and total ES 2 AFUDC accrued to date, is shown below in **Table 6 – ES 2 AFUDC as of June 30, 2020**.

Table 6 – ES 2 AFUDC as of June 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Total AFUDC
Electric Station Flood Mitigation	**$9,887**	**$62,618**	**$191,807**	**$264,312**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$225**	**$14,752**	**$60,073**	**$75,050**
Grid Modernization - ADMS	**$96**	**$7,092**	**$28,474**	**$35,662**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$254**	**$2,590**	**$8,465**	**$11,309**
Total	**$10,462**	**$87,052**	**$288,819**	**$386,333**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. This rate is higher than the 2019 rate of 6.34%, primarily due to a significantly lower average short-term debt balance during the first quarter of 2020, with its lower associated component cost relative to cost of equity and embedded cost of long-term debt. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2020, based on data as of June 30, 2020, the recalculated weighted average AFUDC accrual rate (6.93%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the first quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 projects during the second quarter of 2020 increased significantly over AFUDC accrued during the first quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2020 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity

receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed pursuant to the methodology, as revised in the Company's December 15, 2008 notice to the Board, which included one multi-factor formula that equally weights the PSEG Operating Company values of Net Fixed Assets, Headcount, and Operations & Maintenance.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Overhead Allocations as of June 30, 2020** are the allocated overhead costs charged to ES 2 projects for the second and first quarters of 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 7 – ES 2 Overhead Allocations as of June 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Total Overhead Allocations
Electric Station Flood Mitigation	**$286,953**	**$1,648,117**	**$3,560,216**	**$5,495,286**
Contingency Reconfiguration	**$3,415,460**	**$4,692,085**	**$3,055,700**	**$11,163,245**
Grid Modernization – Communications	**$12,074**	**$345,720**	**$548,017**	**$905,811**
Grid Modernization – ADMS	**$10,603**	**$116,442**	**$91,786**	**$218,831**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$15,287**	**$52,836**	**$68,257**	**$136,380**
Total	**$3,740,376**	**$6,855,199**	**$7,323,975**	**$17,919,550**

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2020 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

5. ES 2 Program Internal Audit

In large companies such as Public Service Enterprise Group (PESG), parent company of PSE&G, the Internal Audit department's objective is to systematically evaluate the firm's management control and governing processes, specifically as they relate to the integrity of financial reporting and compliance with applicable regulations.

PSEG's Internal Audit (PSEGIA) department reports functionally to the Audit Committee of the Board of Directors and administratively to the Chief Financial Officer (CFO), which is to ensure both an atmosphere of independence and a degree of objectivity and prominence, such that its findings and recommendations can be fully vetted with the appropriate corporate audience.

Shortly after its engagement as monitor for the ES 2 Program, the IM held preliminary discussions with PSEGIA personnel regarding a potential audit of the ES 2 Program, similar to the audits it conducted during the first Energy Strong Program. Following these discussions, PSEGIA has indicated that it intends to: (i) conduct a full-scope audit, likely of the Electric Station Flood Mitigation and Contingency Reconfiguration subprograms, beginning in the second quarter of 2021, (ii) in 2022, conduct a full-scope audit of the ES 2 subprograms not covered in the first audit, and (iii) conduct a review of the ES 2 Program in 2023, the scope and depth of which will depend on the results of the previous audits. The IM and PSEGIA will have continued discussions prior to and during the audits to ensure the audits cover those areas specific to cost accumulation as required by the Stipulation. The IM will report on the progress and conclusions of the audits as information is available, and in similar fashion as it did with the audits conducted in the first Energy Strong Program.

D. System Performance

During the second quarter of 2020, PSE&G experienced a Major Event on June 3-7, 2020 stemming from a derecho and severe thunderstorms that primarily affected its Southern Division. This series of storms first entered PSE&G's service territory in the afternoon of June 3, 2020, bringing wind gusts of over 70 miles per hour. By the June 3, 2020 1:00pm operations conference call, the Southern Division reported that it experienced multiple sub-transmission and distribution circuit lockouts and crews were dispatched from the other PSE&G Divisions and from its Projects & Construction (P&C) group to aid in recovery efforts. During this afternoon call, PSE&G's weather service indicated that a second line of storms with similar wind speeds and possible tornadoes was expected that evening. Conference calls later in the day continued to analyze the outages experienced thus far and prepared for upcoming weather impacts. On the June 4, 2020 8:00am operations conference call, the Southern Division reported the evening storms on June 3, 2020 caused additional plant damage and more tree damage, while PSE&G's weather service predicted yet another round of severe thunderstorms was expected later that day and did cause additional damage.

These series of storms led to 257,209 PSE&G customers experiencing service interruptions, with 246,075 of those customers located in the Southern Division. 45% of the customers interrupted were restored within one day, 81% within two days, 97% within three days, and full restoration in just over four days. The IM calls attention specifically to the Woodlynne substation that was shut down during these storms due to both 26kV supply lines being interrupted due to tree/vegetation issues, affecting service to 11,319 customers. An emergency tie line installed under the original Energy Strong Program allowed the substation to return to service in less than three hours.

The IM received PSE&G's report on the performance of its Energy Strong 2 Program investments from this Major Event and has reproduced the results as follows:

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
ALD 8015	0.12276	
ALD 8026	0.07735	
BAO 8003	0.00096	
BAO 8006		
BEN 8012	0.15243	
BEN 8015	0.00623	
BEN 8021	0.00143	

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
BRU 8011	0.04127	0.00363
BRU 8012	0.01236	
BUS 8011	0.13129	0.04924
CED 8011	0.05594	
CED 8021	0.03575	
CED 8022	0.05071	
CIN 8032	0.32648	1.13907

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
CIN 8043	0.18459	0.16269
CLF 8012	0.00401	
CLF 8013	0.00064	
CLF 8023	0.00895	
CLK 8022	0.06677	0.21086
CLK 8024	0.01526	
CON 8001		
COR 8042	0.02723	
CRX 8003	0.07703	0.00467
DAY 8002	0.03617	
DVB 8013	0.00455	
EAT 8011	0.09890	0.01689
FAW 8014	0.21021	
FAW 8022	0.03342	
FAW 8026	0.00902	
FRA 8021		
GBK 8021	0.06208	
GBK 8023	0.02487	
GBK 8025	0.31504	
HAT 8023	0.01869	
HAT 8035	0.04291	
HAW 8032	0.07658	0.00000
HID 8043	0.06432	
HID 8044	0.08229	
HNC 8015	0.10285	
HNC 8021	0.02280	
HNC 8024	0.21727	
HOE 8047	0.05561	
HOM 8001	0.06027	
HOM 8012	0.00000	
HOM 8014	0.00115	
HOM 8041	0.00000	
JAC 8021	0.00318	
JAC 8023	0.05394	
JAC 8043	0.04897	
KIL 8023		
KIL 8024	0.01504	
KIL 8041	0.02511	
KIL 8044	0.03622	
KIN 8015	0.00194	
KUL 8012	0.02022	
KUL 8022	0.00186	0.00206
KUL 8023	0.00582	
KUS 8004	0.00500	0.03236
KUS 8042	0.07830	0.02334
KUS 8045	0.02505	
LAF 8013	0.00125	0.00126
LAF 8015	0.00354	
LAU 8021	0.22050	
LAU 8023	0.82844	
LAU 8034	0.40130	
LAU 8035	0.29567	
LAW 8014	0.03705	1.01225
LCE 8003	0.15926	0.01544
LCE 8032	0.30801	0.03039
LCE 8043	0.10606	
LCE 8046	0.01692	
LEO 8042		
LEV 8006	0.23842	
LOC 8012		0.04313
LOC 8033		
MAD 8015	0.15514	0.95230
MAD 8031	0.45221	0.01856
MAI 8013	0.05318	
MAR 8004	0.02404	
MAR 8017	0.45014	
MAY 8014	0.03470	0.00505
MAY 8024	0.00558	
MDF 8012	0.58371	0.18948
MDF 8023	0.26488	0.54601
MEA 8013	0.04040	0.00365
MIN 8024		
MON 8003	0.27132	
NBS 8011	0.01516	
NBS 8013	0.00000	
NBS 8023	0.00057	
NED 8022	0.02419	0.00773
NEW 8014	0.01839	
NIT 8007	0.00000	
NRB 8014	0.03116	
PIE 8011		
PIE 8023	0.04636	
PLI 8003	0.00215	
PLI 8005	0.16440	0.01832
POH 8024	0.12643	
RFL 8034	0.02787	
RVR 8031	0.02752	
SAD 8045	0.00284	
SDH 8034	0.00000	
SMV 8013	0.00000	

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
SMV 8021		
SMV 8022	0.01681	
SMV 8023	0.01943	
SPF 8012	0.52501	
SUN 8021		
SWT 8001		

Circuit	5 Year Baseline SAIDI	Report Quarter SAIDI
SWT 8002		
WEW 8011	0.18034	
WEW 8033	0.03506	
WEW 8041		
WFL 8041	0.07197	
WOR 8021		

Following receipt of this data, the IM has followed-up with requests for additional information on this data to establish additional context for these results. This additional information has yet to be received as of the date of this final IM 2020 Second Quarter Report and will be discussed in the next IM report following receipt of that information.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of June 30, 2020 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2020**.

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Jun. 2020		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO							C				IS					CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Jun. 2020		KO						C						IS		CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Jun. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS	CO (Q2)
	Jun. 2020	*Schedule Under Development**																		
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO		C									IS				CO	
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Jun. 2020			KO					OS/C				CO							
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO											C			IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020	*Schedule Under Development*																		

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Jun. 2020			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Jun. 2020			KO	C				OS				CO							
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Jun. 2020		KO						C					IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Jun. 2020			KO										C			IS			CO (Q4)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Jun. 2020			KO			C												IS	CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Jun. 2020		KO												C			IS		CO (Q2)

Dec. 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Lakeside Avenue project had a schedule previously developed, but due to the proposed mitigation method change that contemplates relocating the substation, the schedule is now being revised and updated.**

A summary of the subprogram status as of the end of the second quarter of 2020 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment POs	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	14	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Lakeside Avenue[3]; Leonia[2]; Kingsland[2]; Market Street[2]; Meadow Road[2]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start	3	Academy Street; Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2020** summarizes the planned activities for each project during the third quarter of 2020, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2020

Station	Upcoming Activities for Q3 2020	Carryover Activities from Q2 2020
1. Academy Street	• 70% estimate completion • Electrical contractor purchase order issued • Major license and permit issued	• None
2. Clay Street	• License and permit package submitted • Design freeze on switchgear arrangement and controls	• None
3. Constable Hook	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
4. Hasbrouck Heights	• Design freeze on switchgear arrangement and controls • Civil and electrical drawings Issued For Review (IFR)	• License and permit package submitted
5. Kingsland	• 50% estimate submittal (revised)	• None
6. Lakeside Avenue	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
7. Leonia	• Major licenses and permits issued • Civil construction start	• None
8. Market Street	• 70% estimate completion • License and permit package submitted	• None
9. Meadow Road	• License and permit package submitted	• None
10. Orange Valley	• Remains in planning/origination stages	• Planning/origination stages with property acquisition still being reviewed for 69kV project at same site
11. Ridgefield 13kV	• Civil contingency construction completion • Major equipment (13kV contingency switchgear) delivered • Start electrical construction (temporary switchgear)	• Civil mechanical and duct bank construction
12. Ridgefield 4kV	• 70% estimate completed	• Civil underground construction
13. State Street	• Major license and permit received (site plan) • Civil and electrical drawings Issued For Construction (IFC)	• License and permit package submitted
14. Toney's Brook	• Civil and electrical drawings IFR • Vendor submittal of final arrangement mechanical drawings to PSE&G for controls IFR	• None

Station	Upcoming Activities for Q3 2020	Carryover Activities from Q2 2020
15. Waverly	• Phase 1 civil and layout drawings IFC • Phase 2 civil and electrical drawings IFR • Major permits submitted • Phase 2 constructability review	• License and permit package submitted
16. Woodlynne	• Major regional licenses and permits received • Contingency drawings IFR and IFC • Civil and electrical drawings IFC •	• License and permit package submitted

The current project estimates, including base and R&C amounts, is shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020**. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend and percentage of actuals to estimate as of the end of the second quarter of 2020, and the forecasted in-service date.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Office	$12,600,000	$4,400,000	$17,000,000	$650,226	4%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$619,335	1%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$101,960	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$531,773	3%
5. Kingsland	Study	$7,100,000	$2,900,000	$10,000,000	$255,665	3%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	442,176	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$713,897	2%
8. Market Street	Study	$24,200,000	$5,800,000	$30,000,000	$7,334,176	24%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$310,637	3%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$294,300	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$1,023,746	4%
12. Ridgefield 4kV	Study	$16,800,000	$4,300,000	$21,100,000	$2,971,169	14%
13. State Street	Office	$21,200,000	$7,400,000	$28,600,000	$378,656	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$414,002	2%

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$814,790	2%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$564,882	3%
Subprogram Total		**$309,000,000**	**$80,000,000**	**$389,000,000**	**$17,421,931**	**4%**

Findings & Observations

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with three projects in construction as of the end of the second quarter of 2020, three projects remaining in the planning/origination phases (the three with proposed mitigation changes discussed in **Section II.A.**), and the remaining projects continuing to advance in design and pre-construction activities.
- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Academy Street

During the second quarter of 2020, approximately $400,000 was spent on the Academy Street project towards its revised mitigation method compared to a forecast of approximately $435,000, which brought the total spend to approximately $650,000. Notable activities completed during the second quarter of 2020 include:

- Civil and electrical drawings IFR and IFC;
- Inside plant constructability review;
- Civil construction purchase order issued;
- Study level estimate internally approved and prepared for URB approval.

The actual spend by quarter for Academy Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$150,398	$99,893	$399,935	$650,226	$17,000,000	4%

As mentioned in the Executive Summary, Academy Street had its Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $12,800,000, or $4.2 million lower than the prior estimate and driven by the change in mitigation method from raise and rebuild to relocate.

2. Clay Street

During the second quarter of 2020, approximately $283,000 was spent on the Clay Street project compared to a forecast of approximately $344,000, which brought the total spend to approximately $619,000. Notable activities completed during the second quarter of 2020 include:

- Preliminary engineering design freeze;
- License and permit package design commencement;
- Scope document signed off; and

- 4kV sheltered aisle switchgear purchase order issued.

The actual spend by quarter for Clay Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$116,409	$219,707	$283,219	$619,335	$42,000,000	1%

3. Constable Hook

Through the end of the second quarter of 2020, the Constable Hook project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Constable Hook as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$17,889	$51,758	$32,313	$101,690	$5,300,000	2%

4. Hasbrouck Heights

During the second quarter of 2020, approximately $188,000 was spent on the Hasbrouck Heights project compared to a forecast of approximately $179,000, which brought the total spend to approximately $532,000. Notable activities completed during the second quarter of 2020 include:

- Detailed design started; and,
- License and permit package submitted.

The actual spend by quarter for Hasbrouck Heights as compared to the URB last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$149,848	$193,879	$188,045	$531,773	$18,000,000	3%

5. Kingsland

During the second quarter of 2020, approximately $43,000 was spent on the Kingsland project compared to a forecast of approximately $23,000, which brought the total spend to approximately $256,000. Notable activities completed during the second quarter of 2020 include:

- Final vendor switchgear arrangement, mechanical, and control drawings were submitted to PSE&G.

The actual spend by quarter for Kingsland as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$104,112	$108,286	$43,268	$255,665	$10,000,000	3%

As mentioned in the Executive Summary, Kingsland had a revised Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $8,300,000, or $1.7 million lower than the prior estimate and driven by a reduction in the switchgear procurement commitment.

6. Lakeside Avenue

Through the end of the second quarter of 2020, the Lakeside Avenue project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Lakeside Avenue as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$148,943	$172,224	$121,009	$442,176	$36,100,000	1%

7. Leonia

During the second quarter of 2020, approximately $425,000 was spent on the Leonia project compared to a forecast of approximately $405,000, which brought the total spend to approximately $714,000. Notable activities completed during the second quarter of 2020 include:

- Preliminary design frozen and commencement of detail design;
- Scope document signed off;
- License and permit package submitted; and,
- Contingency plan civil and temporary switchgear drawings IFC.

The actual spend by quarter for Leonia as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$44,792	$244,323	$424,783	$713,897	$32,200,000	2%

8. Market Street

During the second quarter of 2020, approximately $5,144,000 was spent on the Market Street project compared to a forecast of approximately $5 million, which brought the total spend to approximately $7.3 million. Notable activities completed during the second quarter of 2020 include:

- Outside plant construction on overhead poles and 4kV associated pole top equipment to upgrade to 13kV.
- Civil demolition/yard work drawings, control drawings, and electrical demolition drawings IFC.

The actual spend by quarter for Market Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$251,193	$1,938,713	$5,144,270	$7,334,176	$30,000,000	24%

9. Meadow Road

During the second quarter of 2020, approximately $105,000 was spent on the Meadow Road project compared to a forecast of approximately $108,000, which brought the total spend to approximately $311,000. Notable activities completed during the second quarter of 2020 include:

- Design freeze on switchgear arrangement, mechanical, and controls;
- Scope document signed off; and,
- License and permit package design commencement.

The actual spend by quarter for Meadow Road as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$63,128	$142,946	$104,563	$310,637	$9,000,000	3%

10. Orange Valley

Through the end of the second quarter of 2020, the Orange Valley project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed. The actual spend by quarter for Orange Valley as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$77,029	$96,582	$120,690	$294,300	$26,600,000	1%

11. Ridgefield 13kV

During the second quarter of 2020, approximately $500,000 was spent on the Ridgefield 13kV project compared to a forecast of approximately $483,000, which brought the total spend to approximately $1.02 million. Notable activities completed during the second quarter of 2020 include:

- Civil and electrical drawings for contingency switchgear IFC;
- License and permit package submitted;
- Major county licenses and permits received;
- Pre-work performed (138kV monopole relocated and foundation removed);
- Civil mechanical and duct bank construction start.

The actual spend by quarter for Ridgefield 13kV as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$205,982	$317,289	$500,475	$1,023,476	$25,500,000	4%

12. Ridgefield 4kV

During the second quarter of 2020, approximately $2.1 million was spent on the Ridgefield 4kV project compared to a forecast of approximately $2.9 million. The variance in actual versus forecasted spend for the second quarter was predominantly the result of less test pit work required (originally expected to have to dig 12 feet to verify conditions for manhole expansions, however in some place only had to dig three feet deep). This brought the total spend to approximately $3.0 million. Notable activities completed during the second quarter of 2020 include:

- Scope document signed off;
- Railroad agreement received; and,
- Outside plant underground manholes/duct bank civil construction start.

The actual spend by quarter for Ridgefield 4kV as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$143,414	$693,128	$2,134,627	$2,971,169	$21,100,000	14%

13. State Street

During the second quarter of 2020, approximately $173,000 was spent on the State Street project towards its revised mitigation method compared to a forecast of approximately $245,000, which brought the total spend to approximately $379,000. Notable activities completed during the second quarter of 2020 include:

- License and permit package submitted; and,
- Detailed engineering commenced.

Additionally, the property purchase for this project was completed (which is funded and executed under the associated 69kv project). The actual spend by quarter for State Street as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$77,950	$128,288	$172,777	$378,656	$28,600,000	1%

As mentioned in the Executive Summary, State Street had its Study level estimate internally approved at the end of June 2020, which went to the URB for approval in July 2020. The new estimate, which will be detailed in the IM 2020 Third Quarter Report, is $45,100,000, or $16.5 million higher than the prior estimate and driven by the change in mitigation strategy from raise and rebuild to relocate.

14. Toney's Brook

During the second quarter of 2020, approximately $86,000 was spent on the Toney's Brook project compared to a forecast of approximately $128,000, which brought the total spend to approximately $414,000. Notable activities completed during the second quarter of 2020 include:

- Design freeze on switchgear arrangement, mechanical, and controls; and,

Additionally, two of the three property parcels for this project closed during the second quarter of 2020 (which is funded and executed under the associated 69kv project), with the third parcel closing in the third quarter of 2020.The actual spend by quarter for Toney's Brook as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$211,940	$115,747	$86,315	$414,002	$19,700,000	2%

15. Waverly

During the second quarter of 2020, approximately $355,000 was spent on the Waverly project compared to a forecast of approximately $270,000, which brought the total spend to approximately $815,000. Notable activities completed during the second quarter of 2020 include:

- Major equipment (switchgear) purchase order issued;
- Detailed engineering commenced;
- Scope document signed off; and,
- Phase 1 constructability review.

The actual spend by quarter for Waverly as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$103,748	$355,706	$355,335	$814,790	$35,400,000	2%

16. Woodlynne

During the second quarter of 2020, approximately $213,000 was spent on the Woodlynne project compared to a forecast of approximately $284,000, which brought the total spend to approximately $565,000. Notable activities completed during the second quarter of 2020 include:

- License and permit package submitted;
- Site plan approved (county); and,
- Detailed engineering commenced.

The actual spend by quarter for Woodlynne as compared to the last URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$110,982	$240,418	$213,482	$564,882	$19,400,000	3%

B. Contingency Reconfiguration

During the second quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions installing reclosers. However, due to failure of a B-phase potential transformer (PT) on a recloser being energized, all recloser installations were temporarily suspended on May 7, 2020 to allow PSE&G to conduct a root cause analysis of the issue. The root cause analysis, conducted by a third party, determined a pinched wire in the PT junction box caused a secondary fault

that led to the PT failure. The short was grounded before the fuse, which meant the fuse was not blown and could not provide protection to the PT. PSE&G revised its testing procedures to limit the number of times required to be in the PT junction box and to test for ground faults before going to the field. Recloser installations resumed the week of June 22, 2020. While the recloser installation suspension caused the second quarter target of 204 installed reclosers to be missed, during this suspension pole installations continued, and PSE&G also shifted resources to install Hm radios and commission reclosers that were already installed without radios to allow other work in the subprogram to continue to advance. **Table 12 – ES 2 Recloser Status as of June 30, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 yearend targets and current status of engineering, installation, and commissioning.

Table 12 – ES 2 Recloser Status as of June 30, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
		Q2 Qty.	*Total*	*Q2 Qty.*	*Total*	*Q2 Qty.*	*Total*
13kV	800	45	594	84	417	130	130
4kV	179	100	263	14	38	11	11
Total	979	145	857	98	455	141	141

As shown in **Table 12**, engineering continues to stay comfortably ahead of construction, allowing PSE&G flexibility in selecting which projects to initiate construction on and allows the subprogram progress to continue.

The Fuse Saver installations is planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units. The pilot program is expected to be completed by the end of 2020.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2020 are presented in **Table 13 – ES 2 Contingency Reconfiguration Costs as of June 30, 2020**.

Table 13 – Contingency Reconfiguration Costs as of June 30, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$8,893,449	$25,257,404	35%
	Metro	$2,231,431	$3,576,616	$1,946,751	$7,754,798	$21,745,230	36%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$8,132,118	$29,244,631	28%
	Southern	$2,081,220	$4,003,537	$2,098,258	$8,183,015	$27,398,087	30%
Fuse Savers	Central	$9,970	$29,667	$48,444	$88,081	$13,694,230	1%
	Metro	$7,557	$15,498	$28,339	$51,394	$10,537,153	0%
	Palisades	$7,468	$15,259	$16,336	$39,063	$10,834,460	0%
	Southern	$9,792	$21,458	22,973	$54,223	$12,165,607	0%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$33,196,141**	**$150,876,803**	**22%**

Findings & Observations:

- Recloser installations fell behind the second quarter target due to the suspension of installations following the PT failure and corresponding root cause analysis. However, PSE&G continued to advance work particularly through pole installations and commissioning of recloser installed earlier with Hm radios.
- It was appropriate for PSE&G to suspend installations in order to determine the cause of the PT failure so it could determine the cause of the failure and protect the safety of the workers.
- It was reasonable for PSE&G to introduce a pilot program on the Fuse Saver/Hmc radio installations to ensure the devices work as intended prior to commencement of the full scope.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

In June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. Also during the second quarter of 2020, the first shipment of field routers and accessory hardware and Hm radios were delivered to the Divisions and installation commenced. By the end of the second quarter, six retrofit reclosers had been installed, in line with the target quantity for the quarter. PSE&G has made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers.

On the fiber scope, which includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network, 41 installation projects and 12 cutover have been identified, with the first batch of installations expected to be placed in-service during the fourth quarter of 2020 and the cutovers to be completed early in 2021.

The Grid Modernization – Communication System subprogram costs through the end of the second quarter of 2020 are presented in **Table 14 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2020**.

Table 14 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2020

Scope & Division		Q1 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Retrofit Reclosers	Central	$0	$50,613	$150,958	$201,571	$7,389,617	3%
	Metro	$0	$44,164	$139,069	$183,233	$6,357,784	3%
	Palisades	$0	$44,164	$138,485	$182,649	$6,445,616	3%
	Southern	$0	$46,901	$145,479	$192,380	$7,953,623	2%
Fiber	Central	$1,691	$133,115	$272,307	$407,113	$6,990,081	6%
	Metro	$1,457	$109,382	$299,876	$410,715	$4,544,079	8%
	Palisades	$1,582	$194,451	$520,068	$716,101	$3,148,835	23%
	Southern	$4,731	$65,721	$139,575	$210,027	$3,233,586	6%
	Cutovers	$0	$0	$0	$0	$6,735,000	0%
Wireless Network		$74,306	$1,525,801	$2,353,604	$3,953,710	$12,065,231	33%
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$6,457,500**	**$64,863,452**	**10%**

Findings & Observations:

- Retrofit recloser installations began in the second quarter of 2020, but PSE&G made a strategic decision for new reclosers (as part of the Contingency Reconfiguration subprogram) continue to have installation priority of retrofits due to new reclosers providing segregation to the sections they are installed that improves reliability (while retrofits improve communications on the devices, but no segregation).
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, with the notable milestone completed in the second quarter of 2020 being the signing of the Open Systems International Inc. (OSII) contract (with the vendor selection discussed in the IM 2020 First Quarter Report). The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application. The final ADMS release is currently forecasted to go live during the fourth quarter of 2022.

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2020 are presented in **Table 15 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2020**.

Table 15 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2020

Q4 2019	Q1 2020	Q2 2020	Total to Date	Forecast	% of Actuals to Forecast
Actuals					
$36,213	$925,689	$4,430,542	$5,392,444	$39,707,462	14%

Findings & Observations:

- The activities to date on the subprogram continue to be primarily planning activities, including continuing to have workshops with the software vendor and operations.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] As reported in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and

[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

the remaining two-thirds towards outside plant higher design and construction standards. Based on the current study level estimate for the life cycle upgrades (detailed below), the current view shows that approximately 80% of these funds will be applied towards life cycle upgrades, with the remainder going towards the electric outside plant higher design and construction standards. This current ratio is driven by the approval of the four life cycle stations, including risk and contingency funds, to allow their completion within the ES 2 Program window. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction schedules. In accordance with what the Stipulation provides, PSE&G plans to fund some of the lifecycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

The outside plan higher design and construction standards scope of work contemplates replacing the traditional open wire and cross-arm type construction on distribution overheard circuits with spacer cable in targeted locations. PSE&G determined that spacer cable provides significant improvement in customer reliability during storm events and other tree-related events as compared to the traditional methods. At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. As reported in the IM 2020 First Quarter Report, the final circuit selection for this effort was still being developed but has now been completed and was selected from PSE&G's original proposal using historical value of lost load from reportable and major event history. The value of lost load was based on tree-related outages for reportable results and all outages for storm events. The rationale for using all outages in storms was that tree-related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds. This work is currently anticipated to commence in January 2022.

The projects identified from the pool of eligible substations are generally located in congested urban/suburban areas with a small property footprint that makes replacing the equipment while maintaining service a challenge. PSE&G has developed a standardized approach for these life cycle upgrades that should result in efficiencies in design, equipment standardization, and construction, as well as eliminating the need for additional property. Essentially, the approach calls for setting concrete footings and columns between and next to existing feeder rows to support new breaker buildings and switchgear being installed on elevated platforms above the existing feeder rows. Following installation of the new equipment, the service is transferred from the old equipment and the old equipment is demolished.

To prioritize and select the stations receiving investments through the life cycle upgrades efforts, PSE&G performed a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets. PSE&G's ES 2 filing indicated it proposed to replace or retire substations with 4kV assets that are either at or close to end-of-life, with 96 stations identified with these assets. PSE&G evaluated each identified station to determine if the station is still required or if its circuits can be cost effectively converted to 13kV operation (generally those with low customer counts and/or peak loads are best candidates to eliminate with a 13kV circuit upgrade). For remaining stations, Class C stations are prioritized due to the significantly higher risk scores present compared with Class A/B stations, in part due to the fact that the 4kV equipment is in outdoor switchgear and exposed to the elements. The prioritization noted in the ES 2 filing was:

1. Class C stations located where 69kV upgrades are completed or in progress. (15 stations)
2. Class C stations identified for elimination. (13 stations)
3. Class C stations where a full station upgrade is required. (10 stations)

4. Class A & B stations where 69kV upgrades are completed or are in progress or 26kV upgrades are planned. (26 stations)
5. Remaining Class A, B, & C stations not candidates to be completed within the proposed 5-year subprogram. (21 stations)

Of those 15 stations in the top priority, Plainfield, Hamilton, Paramus, and Woodbury were initially selected. These four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate are provided in **Table 16 – ES 2 Life Cycle Station Upgrade Projects**.

Table 16 – ES 2 Life Cycle Station Upgrade Projects

Project	Estimate Level	Base	Risk & Contingency	Total
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000

Additional information on each of these life cycle stations is provided as follows:

1. Hamilton: The Hamilton substation was originally constructed in 1953 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines, two 69/4kV transformers, and eight 4kV feeders. From 2008-2017, the 4kV supply circuits at Hamilton have experienced 67 extended outages and seven momentary outages, for a total duration of nearly 308 hours. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

2. Paramus: The Paramus substation was originally constructed in 1958 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines supplying a six-breaker ring bus, with three 69/4kV transformers, and 12 4kV feeder rows. From 2008-2017, the 4kV supply circuits at Paramus have experienced 116 extended outages and 20 momentary outages, for a total duration of nearly 1,044 hours. Black & Veatch was awarded the A/E scope for this project. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

3. Plainfield: The 4-kV Switchgear at the Plainfield substation is in poor condition. A significant portion of the 4-kV equipment at the station is still original and the metal clad switchgear has rusted and must be addressed. In addition, all of the 4-kV distribution feeders and Tie Feeder currently run through the same manhole and conduit system, which presents the possibility of extended outages to the customers supplied from Plainfield Substation in the event of a cable or splice failure that results in collateral damage to adjacent feeders. This station currently consists of three (3) 69-kV lines supplying a Six (6) - Breaker GIS Ring Bus, with three (3) 69 / 4-kV transformers, twelve (12) 4-kV feeders, one (1) 4-kV Tie Feeder, and two (2) 2.7MVA. Black & Veatch was awarded the A/E scope for this project.

4. Woodbury: The Woodbury substation was originally constructed in 1954 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of four 26kV lines, three 26kV bus section breakers, three 26/4kV transformers, three transformer 4kV breakers, and 12 4kV feeders with voltage regulators and reactors. From 2008-2017, the 4kV supply circuits at Woodbury have experienced 153 extended outages and eight momentary outages, for a total duration of nearly 883 hours. Burns & McDonnell was awarded the A/E scope for this project. The life cycle upgrades contemplate replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation.

The four life cycle stations identified above also completed their key drawing review and initiated the major equipment procurement bid events in June 2020.

Findings & Observations:

- The four selected life cycle stations appears to be following a process consistent with how PSE&G has planned and managed the projects within the Electric Stations Flood Mitigation subprogram.
- The standardized approach PSE&G developed for these life cycle stations is an appropriate approach based on the common aspects of these substations (e.g. small footprint, common scope, etc.) and should provide an effective method for updating these substations while also benefiting from efficiencies through using a standardized approach across the projects.
- The IM agrees with the rationale applied by PSE&G for its circuit prioritization for the outside plant higher design standards, including the value of lost load for tree-related outages on reportable events and all outages for storm events, particularly given that tree/vegetation damage accounts for a majority of the outages during storm events and that the criteria also included tree-related outages for reportable results, further emphasizing this prioritization.
- The electric stipulated base projects remain largely in the planning phase, as such the IM has no additional comments on this component of the ES 2 Program at this time.

F. Gas M&R Station Upgrades

Through the end of the second quarter of 2020, preliminary design continued on each of the Gas M&R stations. **Table 17 – ES 2 Gas M&R Summary Status as of June 30, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 16**, there continues to have been minimal spend to date on the subprogram, with the actual spend primarily related to initial planning efforts.

Table 17 – ES 2 Gas M&R Summary Status as of June 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total to Date	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$143,516	1%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$161,474	1%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$158,283	1%	Jan 2023
4. Mount Laurel	Office	$11,300,000	$6,100,000	$17,400,000	$108,507	1%	Jan 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$137,881	1%	Jul 2023

Project	Estimate Level	Base	Risk & Contingency	Total to Date	Actuals	% of Actuals to Estimate	Forecasted In-Service
6. Westampton	Office	$8,300,000	$4,400,000	$12,700,000	$230,181	2%	Jul 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$939,841**	**1%**	**Jul 2023**
**-Included in the Stipulated Base.*							

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the preparation of bid material and awarding of bids for the design services on the projects (with all now awarded).
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering and other planning activities. For the remainder of 2020, planned activities include continued engineering development, with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in November 2020, and the issuance of purchase orders for the major equipment (building, heaters, pipes, scrubber, valves and regulators) in December 2020. Construction is currently anticipated to begin in September 2021 and be completed in July 2022 (with demolition work continuing through October 2022).

The actual spend by quarter for Camden as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$13,326	$46,691	$83,499	$143,516	$15,400,000	1%

2. Central

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering, including the prior award of the A/E contract to Odin EPC, LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with electrical and instrumentation drawings being IFR in November 2020 (and civil and mechanical in January 2021). Construction is currently anticipated to begin in February 2022 and be completed in September 2022 (with demolition work continuing through January 2023).

The actual spend by quarter for Central as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$6,869	$45,048	$109,557	$161,474	$19,700,000	1%

3. East Rutherford

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning

activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in January 2021. Construction is currently anticipated to begin in February 2022 and be completed in December 2022 (with demolition activities planned for completion in June 2022).

The actual spend by quarter for East Rutherford as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$9,010	$37,747	$111,526	$158,283	$15,900,000	1%

4. Mount Laurel

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to J.F. Kiely Service Co., LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in September 2020, followed by the issuance of purchase orders for major equipment (building, instrumentation, pipes, scrubber, valves and regulators) in October 2020. Construction is currently anticipated to begin in May 2021 and be completed in October 2021 (with demolition activities continuing through January 2022).

The actual spend by quarter for Mount Laurel as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$5,965	$27,804	$74,737	$108,507	$17,400,000	1%

5. Paramus

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with electrical and instrumentation drawings being IFR in November 2020 (followed by civil and mechanical in January 2021). Construction is currently anticipated to begin in August 2022 and be completed in June 2023 (with demolition activities continuing through September 2023).

The actual spend by quarter for Paramus as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$8,842	$37,793	$91,247	$137,881	$19,900,000	1%

6. Westampton

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to NVS, Inc., and other planning activities. For the remainder of 2020, engineering efforts are planned to continue with all drawings (civil, electrical, instrumentation, and mechanical) expected to be IFR in August 2020, followed by the issuance of purchase orders for major equipment (building, instrumentation, pipes, pipe fittings, scrubber, valves and

regulators) in September 2020. Construction is currently anticipated to begin in December 2020 and be completed in March 2021 (with demolition activities continuing through May 2021).

The actual spend by quarter for Westampton as compared to the last approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals					
$8,395	$40,839	$180,947	$230,181	$12,700,000	1%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2020 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

30 DECEMBER 2020

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	With reference to page 9 of the ES2 Q2 2020 Report, please provide any additional details regarding the outage at the Woodlynne substation.	The Woodlyne substation experienced 26kV supply line interruptions, similar to other 26kV outages during this Major Event. Each of these interruptions stemmed from tree/vegetation issues.	**Section D.**
RCR-INF-2	With reference to page 9 of the ES2 Q2 2020 Report, did the Company experience any outages with respect to the other ES 1 or ES 2 substations?	As noted in PSE&G's Major Event report, Bordentown, Collingswood, Ewing, and Woodlynne substations were each shut down during the June 2020 Major Event. Each shut down stemmed from interruptions to the 26kV or 69kV supply lines to the substations. The Ewing substation was part of Energy Strong 1 and Woodlynne is part of Energy Strong 2, however, the nature of these outages was not a water intrusion event, but tree/vegetation interruptions to the supply lines.	No change
RCR-INF-3	With reference to page 9 of the ES2 Q2 2020 Report, when does the Company plan to have preliminary results of the performance of ES 2 circuits relative to unimproved circuits impacted by the June 3-7, 2020 thunderstorms?	The initial information was provided to the IM in early December, which is reflected through the new material added to **Section D** of this IM 2020 Second Quarter Report. The IM has also requested additional information from PSE&G based on its review of the initial data provided, which is expected to be discussed in the next IM report.	**Section D.**
RCR-INF-4	With reference to page 9 of the ES2 Q2 2020 Report, does the Company have results of the performance of ES 1 circuits relative to unimproved circuits impacted by the June 3-7, 2020 thunderstorms?	The initial information was provided to the IM in early December, which is reflected through the new material added to **Section D** of this IM 2020 Second Quarter Report. The IM has also requested additional information from PSE&G based on its review of the initial data provided, which is expected to be discussed in the next IM report.	**Section D.**
RCR-INF-5	With reference to Table 9 of the ES2 Q2 2020 Report, is the Company getting pricing discounts or preferential deliveries with suppliers for equipment given the scope of the substation work?	PSE&G has indicated to the IM that it has not received discounts or preferential deliveries relating to the substation work. All pricing and delivery dates originated from the competitive bid process.	No change
RCR-INF-6	With reference to page 13 of the ES2 Q2 2020 Report, please confirm that the $399,935 spent on the Academy Street substation was associated with the change in design strategy discussed during the 2nd quarter.	These funds were spent entirely on the new/current mitigation method.	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-7	With reference to page 17 of the ES2 Q2 2020 Report, please confirm that the $172,777 spent on the State Street substation was associated with the change in design strategy discussed during the 2nd quarter.	These funds were spent entirely on the new/current mitigation method.	**Section III.A.13.**
RCR-INF-8	With reference to page 18 of the ES2 Q2 2020 Report, please provide an update on the status of the root cause analysis. Has the Company experienced equipment failures associated with earlier recloser installations?	The root cause analysis from the May 2020 PT failure was provided to the IM in December 2020. Based on the IM's review of this analysis, additional information has been provided on this event in **Section III.B.** of this IM 2020 Second Quarter Report. PSE&G has informed the IM there has been one other recloser PT failure that occurred in October 2019.	**Section III.B.**
RCR-INF-9	With reference to page 21 of the ES2 Q2 2020 Report, has the ongoing remote working sessions impacted the schedule of ADMS implementation?	The Covid-19 protocols including the remote working sessions with the ADMS vendor, while not the original plan, this approach has not impacted the ADMS implementation schedule.	No change
RCR-INF-10	With reference to page 22 of the ES2 Q2 2020 Report, has the Company developed evaluation criteria to identify spacer cable installations?	Circuit selection has been completed. The value of lost load was based on tree related outages for reportable results and all outages for storm events. The rationale for using all outages in storms was that tree related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds.	**Section III.E.**
RCR-INF-11	With reference to page 22 of the ES2 Q2 2020 Report, please provide details of the four lifecycle upgrade projects for the Electric Stipulated Base component.	Additional information on these four lifecycle upgrade projects has been incorporated into this report.	**Section III.E.**
S-INF-1	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020 What can be attributed to the significant increase in the forecasted cost of the Contingency Reconfiguration subprogram from the Q1 2020 Update ($119,496,564) to the Q2 2020 Update ($150,876,803)?	Driven in part by the full forecasting of the Fuse Saver scope of the subprogram, which as of Q1 2020 had only been partially forecasted. The IM further notes that while this is report covers the second quarter, as of the third quarter of 2020 the Contingency Reconfiguration subprogram forecast decreased to $131.9 million.	**Section I.**
S-INF-2	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2020 What can be attributed to the change in the forecasted completion date of the Grid Modernization – ADMS subprogram from the Q1 2020 Update (Dec. 2023) to the Q2 2020 Update (Oct. 2022)?	Primarily attributed to additional schedule development from the initial high-level schedule that was in place as of Q1 2020 to a more detailed schedule in place as of Q2 2020.	**Section I.**
S-INF-3	Reference Page 10, Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2020 a. Regarding the Electric Station Flood Mitigation projects, please confirm that all A/E contracts were awarded based on bid price.	a. All A/E contracts were awarded through a competitive bid process. b. Driven by the capabilities and availability of in-house resources.	No change

ID #	Question/Comment	IM Response	Report Changes
	b. Please describe the circumstances under which PSE&G internal resources would serve as the A/E.		
S-INF-4	Reference Page 13 (Academy Street) Regarding the statement "Academy Street had its Study level estimate internally approved at the end of June 2020, which went to the [Utility Review Board] for approval in July 2020", please confirm that construction began on Academy Street in Q2 2020 (See Page 9, Table 8), before approval was received from the Utility Review Board.	The civil construction PO was issued in June 2020, along with the release of civil IFC drawings and a constructability review. Actual construction commenced in July 2020. The Office level estimate for Academy Street (and all other Electric Station Flood Mitigation projects) was approved before the URB in September 2019. The July 2020 URB approval for Academy Street related to the project transitioning from an Office level to a Study level estimate.	No change
S-INF-5	Reference Page 19 (Contingency Reconfiguration) Regarding the statement "The Fuse Saver installations is planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units." a. What is the approximate timeline of the pilot program? b. Will the pilot program delay the anticipated completion date of the Contingency Reconfiguration subprogram?	a. November-December b. No expected impact to the overall completion of the subprogram; in fact, intent of pilot program is to identify potential equipment/installations issues to avoid impacts during full implementation of the Fuse Saver devices.	**Section III.B.**
S-INF-6	Reference Page 21 (Electric Stipulated Base) Please provide additional details describing the Company's decision to now spend approximately 80% of the Electric Stipulated Base on life cycle upgrades, rather than approximately 33% as previously estimated in the IM 2020 Q1 Report.	While the Stipulation provided that the $100M in electric stipulated base "will be spent at the Company's discretion toward electric outside plant higher design and construction standards ('outside plant') and/or electric life cycle subprograms identified in the June 8, 2018 ES II filing." PSE&G's intent remains to allocate approximately 1/3 of the Electric Stipulated Based funding to lifecycle station upgrades. The current ratio roughly allocates 4/5 of this funding to the lifecycle station upgrades is reflective of the funding approval for the initial four substations (Hamilton, Plainfield, Paramus, and Woodbury) including the risk and contingency allowance for each substation. The funding approval allows these projects to be initiated in alignment with the ES 2 Program duration. In accordance with what the Stipulation provides, PSE&G plans to fund some of the lifecycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-7	Reference Page 22 (Electric Stipulated Base) Regarding the statement "At present, approximately 45% of PSE&G's 4kV and 13kV overhead distribution system uses spacer cable. As reported in the IM 2020 First Quarter Report, the final circuit selection for this effort is still being developed but will be selected from PSE&G's original proposal using historical value of lost load from reportable and major event history." a. Please confirm that the historical value of lost load reflects all outages, rather than only tree-related outages. b. If so, please discuss if the IM believes it is appropriate to select circuits for spacer cable installation based on the historical value of lost load, rather than the circuit's tree-related outage history.	The value of lost load utilized by PSE&G was based on tree related outages for reportable results and all outages for storm events. PSE&G's rationale for using all outages in storms was that tree related damage represents the large majority of outages during storms and the stronger poles, metal hardware and steel messenger cable all provide higher strength to resist high winds. The IM agrees with this rationale, particularly given that tree/vegetation damage accounts for a majority of the outages during storm events and that the criteria also included tree-related outages for reportable results, further emphasizing this prioritization.	**Section III.E.**
S-INF-8	Reference Page 22, Table 16 – ES 2 Life Cycle Station Upgrade Projects Please describe the factors considered by the Company in selecting the four (4) life cycle station projects in Table 16 for inclusion within the Program.	PSE&G performed a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets. PSE&G's filing indicated it proposed to replace or retire substations with 4kV assets that are either at or close to end-of-life, with 96 stations identified with these assets. PSE&G evaluated each identified station to determine if the station is still required or if its circuits can be cost effectively converted to 13kV operation (generally those with low customer counts and/or peak loads are best candidates to eliminate with a 13kV circuit upgrade). For remaining stations, Class C stations are prioritized due to the significantly higher risk scores present compared with Class A/B stations, in part due to the fact that the 4kV equipment is in outdoor switchgear and exposed to the elements. The prioritization noted in the ES 2 filing was: 1. Class C stations located where 69kV upgrades are completed or in progress. (15 stations) 2. Class C stations identified for elimination. (13 stations) 3. Class C stations where a full station upgrade is required. (10 stations) 4. Class A & B stations where 69kV upgrades are completed or are in progress or 26kV upgrades are planned. (26 stations)	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
		5. Remaining Class A, B, & C stations not candidates to be completed within the proposed 5-year subprogram. (21 stations) Of those 15 stations in the top priority, Plainfield, Hamilton, Paramus, and Woodbury were initially selected.	
S-INF-9	Reference Page 23 (Gas M&R Station Upgrades) Regarding the Gas M&R Station Upgrades: a. Please confirm that all A/E contracts were awarded based on bid price. b. Please identify the entity that was awarded the A/E contract for the Camden M&R project.	a. All awarded on bid pricing. b. Burns & McDonnell was awarded the contract in July 2020 after the work was re-bid following the initially selected firm not agreeing to PSE&G's terms and conditions regarding material procurement.	No change
PSE&G-1	Table 6, Grid Modification – Communications Total AFUDC should be $38,148.	The correct total has been added to **Table 6.**	**Table 6**
PSE&G-2	Table 6, Grid Modification – ADMS Total AFUDC should be $22,926.	The correct total has been added to **Table 6**.	**Table 6**
PSE&G-3	Academy and State were at Study estimates though URB approval was pending. The estimate phase and numbers should be updated to Study data. Academy Base - $9,900,000 R&C - $2,900,000 State Street Base - $39,000,000 R&C - $6,100,000 Kingsland – Phase shows Study phase which is right but the number is office data. Number should be updated to Study numbers Kingsland Base - $5,400,000 R&C - $2,900,000	As noted in the discussion on the estimates for these projects, the values displayed are reflective of the current estimate approved by the URB. While Academy Street, State Street, and Kingsland had updated estimates approved internally in June, these estimates were not approved by the URB until July, as such, the IM reported the previously approved URB estimates for these projects (while also noting the URB approval was pending).	No change
Rate Counsel 12/7/2020 Letter to IM	Rate Counsel also notes that the budget for Electric stipulated base has been set to $100 million, but that Pegasus states that the subprogram's projects "remained largely in the planning stage."	The $100 million budget for the electric component of the Stipulated Based was established by the Stipulation. This component of the ES 2 Program has largely remained in the planning stage, as evidenced by the selection of the initial life cycle stations reported in this report and the establishment of criteria for higher design standards.	No change
Rate Counsel 12/7/2020 Letter to IM	The Electric Flood mitigation program increased from $309,160,283 in the First Quarter Report to $332,662,596 in the Second Quarter Report, not including risk and contingency estimates. However, Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2020, states that the base spending amount for the subprogram is $309,000,000 in budgeted base project costs and $80,000,000 allocated to risk and contingency.	The $309,160,283 figure reported in the IM 2020 First Quarter Report and the $332,662,596 figure reported in this IM 2020 Second Quarter Report reflect PSE&G's <u>current forecasted</u> spend for the Electric Station Flood Mitigation subprogram. The figures presented in Table 11 depict the <u>latest estimate</u> for each of the substations within this subprogram, including designation of the current estimate level.	No change

ID #	Question/Comment	IM Response	Report Changes
		It is common for the current forecast to differ from the latest estimate based on the forecast including trends and other more current metrics (which would be captured by the next revision to the project estimate).	
Rate Counsel 12/7/2020 Letter to IM	The Independent Monitor notes that no formal RODs were issued during the second quarter of 2020, however, PSE&G has proposed additional mitigation method changes at three substations in the Electric Station Flood Mitigation subprogram: the Lakeside Avenue, Orange Valley, and Constable Hook substations.	The IM concurs that no formal RODs were issued during the second quarter of 2020. The IM also notes that while these mitigation changes were raised during the second quarter, as noted in this IM 2020 Second Quarter Report, the formal notification was not submitted by PSE&G until the third quarter of 2020 and will be discussed in more detail in the IM 2020 Third Quarter Report.	No change
Rate Counsel 12/7/2020 Letter to IM	Similarly, the Contingency Reconfiguration subprogram total forecast increased to $150,876,803 from $119,496,564 in the First Quarter Report. The stipulated budget for the subprogram is $145 million. Nonetheless. Pegasus concludes that "[w]hile still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget."	The IM notes that it is still early in the subprogram and as the planning and forecasting becomes more solidified based on the initial efforts it is expected the forecast will be less volatile. This second quarter forecast increase to the Contingency Reconfiguration subprogram was driven in part by the full forecasting of the Fuse Saver scope of the subprogram, which as of Q1 2020 had only been partially forecasted. The IM further notes that while this is report covers the second quarter, as of the third quarter of 2020 the contingency reconfiguration subprogram forecast decreased to $131.9 million.	**Section I.**
Rate Counsel 12/7/2020 Letter to IM	The amounts set forth in the Second Quarter Report Tables should be amended so that the stipulated amounts for the ESII program are clearly stated.	This information has been added to **Table 1**.	**Table 1**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2020 THIRD QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

11 MAY 2021

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Key Decisions 3
B. Program Management 13
C. Cost Assignments 14
D. System Performance 17
III. Project Status 25
A. Electric Station Flood Mitigation 25
B. Contingency Reconfiguration 35
C. Grid Modernization – Communication System 37
D. Grid Modernization – ADMS 38
E. Electric Stipulated Base 39
F. Gas M&R Station Upgrades 42
IV. Additional Information Following the End of the Third Quarter of 2020 46
A. Decisions Recorded After the Third Quarter of 2020 46
B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes 47

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS

Air Insulated Substation..... AIS

Allowance for Funds Used During Construction ..... AFUDC

Architectural and Engineering ..... A/E

Board of Public Utilities ..... BPU

Construction Work In Progress..... CWIP

Costs of Removal..... COR

Distribution Management System..... DMS

Distributed Energy Resource Management System ..... DERMS

Energy Strong 2 ..... ES 2

Gas Insulated Substation..... GIS

Gas Metering & Regulating ..... Gas M&R

Independent Monitor..... IM

Infrastructure Investment Program..... IIP

Issued for Construction ..... IFC

Issued for Review ..... IFR

Open Systems International Inc. ..... OSII

Operations & Maintenance ..... O&M

Outage Management System..... OMS

Plain Old Telephone Service..... POTS

Public Service Electric & Gas ..... PSE&G

Record of Decision ..... ROD

Risk and Contingency ..... R&C

State of New Jersey Division of Rate Counsel..... Rate Counsel

Supervisory Control And Data Acquisition..... SCADA

System Average Interruption Duration Index ..... SAIDI

Underground Storage Tanks ..... USTs

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019 with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the third quarter of 2020, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects now in construction, up from three in the prior quarter; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers, despite encountering weather-related impacts and minor inventory issues. Within the other subprograms, the two Grid Modernization subprograms continued to advance with the Communications piece primarily focusing on readying the new network and preparing for the selected 2020 fiber projects that were initiated in the fourth quarter of 2020 and the ADMS piece continuing to plan and scope the platform and necessary hardware equipment, while the Gas M&R subprogram largely remains in preliminary planning and early engineering activities. As noted in the Independent Monitor's (IM's) 2020 Second Quarter Report, four stations within the life cycle upgrades portion of the Electric Stipulated Base were approved by the Utility Review Board (URB) in July 2020, which initiated the initial spend on these projects during the third quarter of 2020 as design and permitting efforts began. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020

Subprogram	Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	**$16,058,679**	**$33,480,071**	**$327,092,250**	**10%**	**Jan 2024**	**$389M**
Contingency Reconfiguration	**$10,289,616**	**$43,485,758**	**$131,898,033**	**33%**	**Jul 2023**	**$145M**
Grid Modernization – Communications	**$5,106,396**	**$11,563,893**	**$59,120,939**	**20%**	**Dec 2023**	**$72M**
Grid Modernization – ADMS	**$6,970,572**	**$12,363,016**	**$40,374,822**	**31%**	**Oct 2022**	**$35M**
Electric Stipulated Base	**$1,473,779**	**$1,473,779**	**$100,103,160**	**1%**	**Under Development**	**$100M**
Gas M&R Station Upgrades^	**$1,178,542**	**$2,118,383**	**$76,200,001**	**3%**	**Jul 2023**	**$101M**
Total*	**$41,077,584**	**$104,484,899**	**$734,789,205**	**14%**	**Dec 2023**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 20 and **Table 19** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

From the second quarter of 2020, the overall ES 2 Program forecast decreased from approximately $747 million to $734.8 million. This was largely driven by an approximate $18 million decrease in the Contingency Reconfiguration subprogram forecast, which was slightly offset by an approximate $10.6 million increase in the Gas M&R subprogram forecast. The change in the Contingency Reconfiguration subprogram forecast from the second to third quarter of 2020 was predominantly driven by the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing. The change in the Gas M&R forecast was predominantly driven by an increase to the forecast for the Central M&R project from $12.8 million as of the second quarter of 2020 to $23.9 million as of the third quarter of 2020. This forecast was validated and incorporated into the project's Study level estimate that was approved at $30.0 million (including R&C) in December 2020. The increase was driven by higher construction costs based on the engineer's 50% estimate, additional buildings and equipment required for the refined design, and additional project management, engineering, and licensing and permitting support not included in the prior estimate.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$11,800,000	$1,962,997	17%	10/25/2021
2. Clay Street	$42,000,000	$853,506	2%	1/12/2023 (↓)
3. Constable Hook	$5,300,000	$110,380	2%	TBD
4. Hasbrouck Heights	$18,000,000	$857,466	5%	12/2/2022 (↓)
5. Kingsland	$8,300,000	$283,143	3%	10/4/2023
6. Lakeside Avenue	$36,100,000	$529,588	1%	12/29/2023 (↓)
7. Leonia	$32,200,000	$1,785,365	6%	12/2/2022 (↓)
8. Market Street	$30,000,000	$12,273,747	41%	9/22/2021
9. Meadow Road	$9,000,000	$483,601	5%	9/21/2023
10. Orange Valley	$26,600,000	$358,732	1%	1/22/2024
11. Ridgefield 13kV	$25,500,000	$3,997,876	16%	10/7/2022 (↑)
12. Ridgefield 4kV	$20,200,000	$6,745,564	33%	6/30/2021
13. State Street	$45,100,000	$596,495	1%	9/23/2022
14. Toney's Brook	$19,700,000	$510,253	3%	4/21/2023
15. Waverly	$35,400,000	$1,465,452	4%	11/16/2023 (↑)
16. Woodlynne	$19,400,000	$665,906	3%	9/26/2023

**-Reflects the in-service date of the last major asset (e.g., switchgear), certain activities may take place after this date to support the final in-service date (i.e., when all customers are cutover).*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As indicated in **Table 2**, the Market Street and Ridgefield 4kV projects continue to have the highest percentage of spend, which is reflective of these two projects advancing further into construction. Additionally, three of the stations (Academy Street, Kingsland, and State Street) had new estimates approved by the URB in July 2020. **Table 2** also shows that six of the sixteen projects in this subprogram had movement in the forecasted in-service date, with two advancing and four slipping. Of these six projects, only one (Lakeside Avenue) had movement more than 60 days, which is the threshold the IM applied during the original Energy Strong Program for evaluating the project schedules. Lakeside Avenue's delay is driven by the original property purchase location for the corresponding 69kV project falling through while a new potential property purchase is underway.

While early in the subprogram, the IM has found nothing to date that would jeopardize the ES 2 Program being completed on time and/or on budget.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On March 11, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their rationale and any impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section II.B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section II.B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See **Section II.A.1**. below)*
Grid Modernization – Communication System	Substation Communication Cutover	Reasonable and appropriate *(See **Section II.A.2**. below)*

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Pending review of additional information *(See **Section II.A.3.** below and **Section IV.B.**)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See **Section IV.A.** below)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-2 Units	Under initial review

1. Grid Modernization – Wireless Communication Network

The initial proposal for a wireless network solution included a self-contained network not reliant on any third-party carriers. On July 6, 2020, PSE&G recorded a ROD to detail why this was not a component of the selected FirstNet solution (this selection was initially discussed in the IM 2020 First Quarter Report).

One of the major components of the Grid Modernization subprogram is to create a high-speed wireless network across the PSE&G service territory. The network will be leveraged to communicate with a broad range of electric distribution field assets. PSE&G considers reliability, redundancy, and resilience to be key characteristics required for the communication platform. In order to achieve these objectives, required capabilities of the network include high-bandwidth transmission, minimal latency, industry standard encryption and authentication, and the ability to prioritize traffic based on hierarchical classification. In addition, PSE&G has determined that the communication network must communicate wirelessly with PSE&G's underground electric distribution network through manholes and vaults. PSE&G has further noted to the IM that full coverage in underground residential developments where there is no overhead electric construction is also required.

Alternatives considered include:

1. ABB Mesh Network – operating in unlicensed public spectrum;
2. Nokia LTE Network – operating based on a 2.5 GHz spectrum band;
3. AT&T LTE Network – operating based on a 2.3 GHz spectrum band;
4. Hybrid Solution: Multiple Vendors – proposing operating on proposed re-banding of 900 MHz spectrum; and
5. FirstNet: Public/Private Partnership with the Federal Government – operating on a 700 MHz spectrum band.

The initial proposal for how to create a high-speed wireless network across the PSE&G territory stated that the network would be completely self-contained and not reliant on any third-party public commercial communication carriers. The decision as discussed herein, determined this not to be a component of the selected alternative.

The total vendor costs including the network construct and the cost to purchase the spectrum (and not including the annual operating and maintenance costs) ranged from $28.7 million to $238 million, with the FirstNet being the lowest cost.

FirstNet is a nationwide wireless broadband network for first responders being built and deployed through a public-private partnership between the federal government and AT&T. FirstNet offers first responders a dedicated communications network built and customized to meet their needs. As a corporation in the utility industry that works with public safety and first responders during emergency responses, PSE&G qualifies as an Extended Primary FirstNet User.

As the Federal Government's choice to be the exclusive FirstNet network provider, AT&T is uniquely positioned to provide these services. AT&T is the only vendor that can properly configure, provision, and optimize the routers for use on their FirstNet network. Utilizing another vendor for these services was not considered due to AT&T's exclusive agreement with the Federal Government for management and oversight of the FirstNet network.

In its decision-making process, PSE&G, after an evaluation and analysis, determined that building a solely owned and operated communication network would not be prudent. The evaluation and analysis concluded that the cost to construct a privately owned network and the purchase of the required spectrum for LTE solutions was much higher than anticipated (with an estimated cost of $87 million to purchase spectrum up front or an estimated cost of $156 million to lease spectrum over 20 years). In addition, PSE&G's evaluation found that the time to obtain the proper permitting and network construction would add risk to the project timelines. While the ABB mesh solution operated on unlicensed frequencies the total number of network devices (30k), the cost to construct and maintain were determined by PSE&G not to be practical or easily maintainable.

Findings and Observations

- The IM finds that PSE&G conducted the appropriate due diligence, evaluation, and analysis in determining its solution to create a high-speed wireless network across the PSE&G electric service territory.
- While the FirstNet is the lowest cost solution, the solution also provides a network that is already being used by First Responders nationwide and was already vetted and chosen by the Federal Government.
- The decision will provide the required reliability, redundancy, and resiliency for the communication platform.

2. Grid Modernization – Substation Communication Cutover

On October 29, 2020, PSE&G recorded a ROD to cutover primary SCADA communications at substations where PSE&G's fiber backbone is installed but not yet connected and to install Nokia Hmc radios and cutover backup Substation communications to the new FirstNet Wireless Network (see related discussion in **Section II.A.1**).

Alternatives were considered which included:

1. Do nothing and maintain 3rd party fiber, "plain old telephone service" (POTS) lines and/or Verizon 4G as the primary and backup communication for SCADA at PSE&G's substations, and
2. Cutover primary SCADA communications to existing PSE&G fiber and backup communications to the new FirstNet Wireless Network.

The PSE&G 2018 filing included provisions to effectively eliminate PSE&G's reliance on POTS or Verizon 4G for critical operational communications. POTS lines were predominately provided by copper wire, which is unreliable during major weather events. In addition, Verizon no longer maintains POTS lines and is in the process of upgrading its network to fiber. PSE&G has noted that while the Verizon upgrade is expected to improve reliability, PSE&G would incur costs to connect the communication equipment and would still be reliant on a third-party provider.

The primary communication for the SCADA system at substations will be PSE&G's Fiber Backbone. Twelve substations that currently have the fiber backbone but have not yet been connected to the network will be cutover. The backup communication inside approximately 218 substations will have Nokia Hmc

radios installed and will be cutover to the FirstNet solution, a public safety network dedicated, built, and customized for First Responders.

12 substations are currently included in the Fiber Cutover initiative including: Delair, East Riverton 2, Elizabeth Sub, Fairview, Henry Street, Mount Holly, Polk Street, Riverside-13kV, Spring Valley Rd, Tonnelle Avenue, Union City and West Orange Sub. The substation division where FirstNet wireless communication will be leveraged include: Central (61), Metro (61), Palisades (21) and Southern (75).

The IM inquired with PSE&G as to whether there is an estimate of the anticipated operational cost savings from the elimination of POTS lines and 4G. PSE&G responded that the estimated savings from the Substation Cutover program from disconnecting third party POTS lines and 4G are as follows:

- Annual O&M Communication Plan savings (218 substations): $17,668/year.
- One-time avoided O&M costs from eliminating the requirement of transitioning existing POTS lines over to Verizon Fiber (205 Substations): $773,670.

Findings and Observations

- By leveraging the existing PSE&G Fiber Backbone for primary communication to substations with SCADA will effectively eliminate PSE&G's reliance on POTS lines or Verizon 4G for any critical operational communications inside substations that contain SCADA.
- Transitioning all backup SCADA communications for 218 substation RTUs to the new FirstNet Wireless Network will ensure ruggedized communication redundancy to PSE&G substations in the event of a hardware or infrastructure failure.
- By making the changes, PSE&G will incur lower operational costs achieved by the elimination of the POTS lines and 4G and improved reliability of communication during storm events.
- The IM finds that PSE&G appropriately investigated the alternatives and making its decision focusing on the long-term reliability for customers while at the same time evaluating the operational cost for that long-term reliability.
- The IM further finds that PSE&G's decision will have both a one-time cost benefit as well as an annual savings benefit to customers.

3. Electric Station Flood Mitigation – Lakeside Avenue, Orange Valley, and Constable Hook Change in Mitigation Method

Following the previous change in mitigation method to the Academy Street and State Street substations (discussed in the IM 2020 First Quarter Report), PSE&G indicated that it continuously assesses and reassess it transmission and distribution projects to consider overall systems needs and scheduled improvements. From these reviews, PSE&G determined that the Lakeside Avenue, Orange Valley, and Constable Hook projects in the Electric Station Flood Mitigation subprogram presented opportunities to combine transmission and distribution work to gain project and cost efficiencies. On September 24, 2020, PSE&G formally notified the BPU and other parties of the proposed change in mitigation method for certain the Lakeside Avenue, Orange Valley and Constable Hook projects. The information presented within this **Section II.A.3.** is intended to convey the status of this decision as of the end of the third quarter of 2020, additional information reviewed by the IM as of the date of this report, but outside of the third quarter of 2020, is provided in **Section IV** and will also be discussed as appropriate in the next IM report.

In regard to the proposed mitigation changes at Lakeside and Orange Valley, from an overall perspective, PSE&G is upgrading network supply to Lakeside, Orange Valley, Toney's Brook, and South Orange

(future) by establishing a 69kV transmission path in Essex County. PSE&G identified that it could combine transmission and distribution work at Lakeside and Orange Valley to gain project efficiencies and reduce the costs of these projects compared to if they were performed separately. The proposed change at Constable Hook is similar in regard to combining the project with other work, but instead of combining the flood mitigation distribution work with a transmission project, the distribution work is being combined with new capacity needs in the area and life cycle replacement needs at the neighboring Bergen Point substation.

Lakeside Avenue

For Lakeside Avenue, PSE&G originally contemplated constructing the distribution and transmission projects at the Lakeside Avenue location noted in the ES 2 filing, which included a rebuild at the existing location. Since the ES 2 filing, PSE&G determined that moving sites to a new property is a better option for several reasons as discussed below including that it would be more costly to perform the ES 2 project and the 69kV transmission project separately.

PSE&G learned in March 2018 that the adjacent property planned for purchase was not available, thus requiring a more complicated construction sequence and the need to temporarily relocate the 4kV switchgear. Further, due to the size of the Lakeside site, a customized design to accommodate both the distribution and transmission facilities on the property would be required as well as the use of contingencies and cutovers to increase safety, environmental and reliability risks.

Prior to the 101 N. Park alternative, PSE&G first considered a property at 338 Washington Street. However, in October 2019, PSE&G deemed that the Washington Street site was not viable due to environmental conditions. PSE&G continued to also consider the existing Lakeside Substation and at this time began to consider 101 N. Park as an option. PSE&G has noted that it expects to acquire the property at 101 N. Park Street in December 2021.

PSE&G has determined that since there is no existing utility operation on the new property located at 101 N. Park Street, the use of contingencies is not required and would allow the substation to be build based on a standard PSE&G design, which PSE&G notes would be better from an operational and maintenance standpoint.

The initial cost estimate of ES 2 project and the 69kV project were $36.1 million and $106 million, respectively. The current estimate, based on the refined study level estimates at the 101 N. Park Street location are $47.9 million and $93.6 million respectively, or an estimated combined savings on the projects of approximately $0.6 million.

PSE&G, in its response to RCR-INF-0001, provided the estimates for the ES 2 and 69kV Lakeside Avenue projects, including the estimate at filing, the Office Level estimate, and the current Study Level estimate, which has been reproduced below in **Table 4 – Lakeside Avenue Project Estimates**.

Table 4 – Lakeside Avenue Project Estimates

Estimate	69kV Project	ES 2 Project	Total
Initial Filing Estimate	$106.0 million	$36.1 million	$142.1 million
Office Level (existing site)	$120.4 million	$47.9 million	$168.3 million
Study Level (101 N. Park Street site)	$93.6 million	$47.9 million	$141.5 million

As shown in **Table 4**, while the combined total is a slight decrease of $0.6 million from the total authorized, the Lakeside Avenue Office Level estimate at the existing site showed an estimate of $47.9 million versus a Stipulation Filing estimate of $36.1 million. The updated Study Level estimate does not change the prior Office Level estimate for the Lakeside Avenue, thus resulting in an $11.8 million increase from the initial estimate for the ES 2 project regardless of site location.

PSE&G described the existing location design noting that the 4kV in the building is a unique design resulting in higher construction and operating costs. The proposed location at 101 N. Park would result in a 4kV standard switchgear arrangements that would have lower construction and operating costs. PSE&G in its response to RCR-INF-0001 described the design of the 101 N. Park Street substation and noted that it would not incorporate loads from other PSE&G substations.

While there is an approximate $11 million increase in the ES 2 Lakeside project estimate from the filing estimate, this increase is not directly tied to the change in mitigation method as it also was realized in the Office Level estimate for the original site. The bulk of the anticipated cost savings are in the 69kV transmission project, which shows a cost reduction of approximately $26 million to perform the work at 101 N. Park versus the original site.

Findings and Observations

- The IM finds that the proposed mitigation mitigates the impacts stemming from the unavailability of the adjacent property as originally planned (complexities to design and construction sequencing due to small site.)
- Construction risk (i.e., no buildings to remove or abatement necessary at new site) is reduced.
- The need for service contingencies is eliminated.
- The new substation at 101 N. Park Street would be a traditional design, thus improving operations and maintenance aspects of the station.
- While there is only marginal cost savings of approximately $0.6 million from the filing estimate by the joint execution of distribution and transmission projects, the mitigation measure avoids costlier option of performing these projects at the existing site-$168.3 million combined estimate at existing site versus $141.5 million combined estimate at the new site.

Orange Valley

With respect to Orange Valley, as with Lakeside Avenue, PSE&G identified transmission upgrades in the same area and determined that it would be less costly to perform both the ES 2 project and the transmission project jointly.

In the ES 2 filing, PSE&G contemplated rebuilding the substation on the existing location. PSE&G proposes to move from the existing Orange Valley site to a larger property approximately 120 feet from the existing station. The adjacent property is a larger property, close to the 230kV and will result in less operational risks as no service contingencies are required. By combining the work, PSE&G has determined that it will be able to avoid the need for a 7-Breaker 69 kV Ring Bus Switchgear that would be required if PSE&G proceeded with the construction at two separate stations. The proposed change thus consolidates the 230kV/69/4kV on a single property.

PSE&G, in its response to S-INF-0002, provided the estimates at filing and the current Office Level estimate for the ES 2 and 69kV Orange Valley projects, which has been reproduced below in **Table 5 – Orange Valley Project Estimates**.

Table 5 – Orange Valley Project Estimates

Estimate	69kV Project	ES 2 Project	Total
Initial Filing Estimate (original site)	$328.0 million	$26.6 million	$354.6 million
Office Level (new site)	$205.3 million	$21.0 million	$226.3 million

Due to the close proximity of the new Orange Valley Substation site and a simpler construction concept, PSE&G expects to complete the ES 2 project work with an expected savings of approximately $5 million from the original estimate. The original concept was based on an over/under design, where the new equipment needed to be constructed at the existing Orange Valley substation site, around and over the old equipment, while the old equipment remained in service. PSE&G noted that this required an intricate design of the foundations, additional steel, and also a detailed, possibly daily, outage schedule for the existing circuits during construction that greatly added to the cost and timing of the construction. The contemplated project and involves construction of the standard sheltered aisle switchgear on a previously cleared property. The cost of the switchgear is purported by PSE&G to be more accurate because it is based on recent switchgear purchases. Further, that recent information reduces the R&C estimate as the only outages will be for the cutover of the circuits, reducing the time spent coordinating construction. PSE&G noted that the common site costs (drainage, security, grading, fencing, etc.) are being shared, with 15% going towards the ES 2 project and 85% towards the larger transmission project. This ratio of common site costs between the ES 2 and 69kV Orange Valley projects was determined by PSE&G based on the ratio of each project's Study level estimated cost of station equipment and structures to the total estimate cost of station equipment and structures for both projects, which was then rounded to the nearest 5%.

PSE&G explained that in order to construct the 69kV network, PSE&G needs a 230/69kV switching station as a source station for the 69kV system. PSE&G discussed the alternatives considered including building Orange Valley on the existing property at 69/4kV and a separate 230/69kV switching station to supply the 69kV network. However, that alternative would require the construction of two separate stations as well as 69kV ring bus at Orange Valley. Building the two stations independently was noted to also require the construction of three new transmission circuits from the 230/69kV switching station to the 69/4kV station at Orange Valley. The elimination of the 69kV ring bus and the extension of three 69kV lines was further noted to be conservatively estimated at savings of $15-$20 million by consolidating the Orange Valley site.

PSE&G responded to RCR-INF-0002 providing a description of the design proposed for the new Orange Valley substation. Further, the Company noted in response to S-INF-0002 that it expected to acquire the nearby property in April 2021, and as of the date of this report PSE&G is still in purchase negotiations regarding the new property. PSE&G confirmed that the Orange Valley substation will not incorporate loads from other PSE&G substations and that the ES 2 distribution work is included in the $26.6 million estimate for the substation. Further, the land costs are also included in the Company's estimate of the combined cost savings of these transmission and distribution projects.

In response to RCR-INF-5 asking for an explanation as to whether the preliminary and/or phase 1 environmental assessment(s) have identified the presence of Underground Storage Tanks (USTs) associated with the current property owners, PSE&G responded that the Phase 1 assessment did identify USTs and that the seller will be responsible to remove all USTs present at the property.

Findings and Observations

- The IM finds that PSE&G conducted its due diligence in its evaluation of whether there would be benefits to customers in combing both the transmission and distribution projects with both consolidation of 230kV/69/4kV on a single property and less operational risk.
- The proposed mitigation also eliminates the need for service contingencies.
- PSE&G has identified savings of approximately $5 million to the Orange Valley ES 2 project resulting from this mitigation change from what was originally contemplated in the ES 2 filing.

Constable Hook

The original ES 2 filing contemplated rebuilding the substation on the existing location. The original project did not have associated transmission costs. Existing units were to be raised above the flood zone under the original project. PSE&G identified an opportunity to combine the flood mitigation work at Constable Hook with new capacity needed in the area based on ongoing development. The proposed change further would eliminate the existing station and construct at new station in the area of Constable Hook and supply the new load at the former Military Ocean Terminal. The new station would serve the existing Constable Hook customers with a storm-hardened facility. By consolidating into a single location, PSE&G determined there would be a better source of 69kV vs. 26kV for storms as well as lower long term operating costs. The existing circuits are very close to the new site and rearrangements can improve reliability at low cost.

The need for additional capacity in the area served by Constable Hook was determined in the spring of 2020 when new residential and electric vehicle growth was identified. The estimated load growth on the Bayonne Peninsula in the areas served by Constable Hook is 25-30MW.

In response to RCR-INF-0003, PSE&G described the design of the new Bergen Point substation noting that Bergen Point is an existing 26/4kV station and that there is no plan for a new station at that location. PSE&G discussed the alternative which was to upgrade the station to 69/13kV but that after evaluation, the alternative had higher costs versus the option of constructing a new Constable Hook station and retiring Bergen Point (approximately $203 million to upgrade the existing Bergen Point station versus approximately $187 million under the new Constable Hook option). The new Constable Hook proposed station to be located on Route 440 was noted to be a 69/13kV station including a 69kV ring bus, two 69/13kV transformers and 13kV sheltered isle switchgear and will eventually allow for the retirement of the Bergen Point substation at some point in the future. However, PSE&G noted that the new Route 440 property has not yet been acquired. Once acquired and upon completion of the new Constable Hook Station, the load will be gradually transferred over by approximately 2028.

PSE&G's Life Cycle subprogram in the ES 2 filing identified Class C stations as a priority over Class A/B stations due to Class C stations being outdoor facilities with metal-clad switchgear, which results in a higher associated risk and poorer performance. The Bergen Point substation is a Class A station where the 4kV equipment is enclosed in a masonry building and thus is a lower risk station per the Company's risk model assessment. However, the station was constructed in 1929 and thus is considered a lifecycle station as PSE&G noted in its ES 2 filing that the majority of the 4kV equipment at these facilities is the original equipment.

The Bergen Point substation and the new Constable Hook substation proposed to be built at the Route 440 property have the same electrical configuration. However, the primary cost difference in the projects is the requirement for a Gas Insulated Substation (GIS) at Bergen Point compared to an Air Insulated Substation (AIS) at the Route 440 property. The GIS station has a much smaller footprint required at the

Bergen Point location but is more expensive while the Route 440 property has the land needed to support an AIS configuration. This proposed change results in approximately $16 million in cost savings compared to upgrading the existing Bergen Point substation to a 69/13kV station ($202.9 million at original site versus $186.9 million at the new Route 440 site, including land and retirement at Bergen Point).

The IM sent a document request to PSE&G requesting 1) the detail of the new identified growth as compared to the prior capacity assumptions, 2) what prompted the review of the area capacity in the spring of 2020 and 3) were the PJM presentations planned for December 2020 and January 2021 conducted. While outside this IM 2020 Third Quarter Report, PSE&G's response to the IM's request confirmed that the new load growth is for the ongoing development on the Bayonne Military Ocean Terminal peninsula. PSE&G further stated that the new load expected to be served on the new substation is estimated at 20-30MW. The review of the area capacity and the new load identified was based on published information regarding development in the area. Regarding PJM, PSE&G noted that the December 2020 Needs Presentation was actually presented in November 2020 although the PJM Solutions presentation planned for January 2021 had not yet been presented as of the date of the response to the IM's questions.

PSE&G has also indicated that the proposed change also offers a planning system for future needs. The proposed change will also support the life cycle replacement needs at the neighboring Bergen Point. As discussed above, PSE&G found in its evaluation that the future elimination of Bergen Point would provide significant cost savings for both transmission and distribution upgrades.

PSE&G, in its response to S-INF-0002, provided the estimates at filing and the new estimate for the proposed new Constable Hook project, which has been reproduced below in **Table 6 – Constable Hook Project Estimates**.

Table 6 – Constable Hook Project Estimates

Estimate	Transmission Cost	Distribution Cost	Total
Initial Filing Estimate (original site)	N/A	$5.3 million	$5.3 million
Proposed Mitigation Change (new site)	$110.77 million	$11.1 million*	$121.87 million*
**-Includes $5.3 million related to the ES 2 flood mitigation project and $5.8 million associated with new substation load growth that is outside the ES 2 Program.*			

Findings and Observations

- The proposed relocation has several benefits including:
  - No change to the planned ES 2 costs in the original filing.
  - Reduction in long term costs of approximately $16 million.
  - Building for the future.
  - Reduced project risk as there is no need for service contingencies.
  - Flood risk is mitigated for Constable Hook Customers.
- The new station addresses identified new load growth, station age/condition at Bergen Point, and flood risk.
- As the existing Constable Hook circuits are very close to the new site, rearrangements can improve reliability at low cost.

- The IM Finds that PSE&G conducted the appropriate due diligence once it determined that by combing both the transmission and distribution projects that there would be multiple benefits to customers in addition to no change in the ES 2 proposed cost for Constable Hook and a reduction in the transmission project cost along with long term operating cost reductions.

Overall Initial Findings and Observations for the Mitigation Changes at Lakeside, Orange Valley, and Constable Hook

While additional information on these mitigation changes has been requested by the IM, based on the current available information the IM identified the pros and cons for each of these three substation mitigation changes in **Table 7 – Evaluation of Substation Mitigation Methods for Lakeside, Orange Valley, and Constable Hook ES 2 Projects** below.

Table 7 – Evaluation of Substation Mitigation Methods for Lakeside, Orange Valley, and Constable Hook ES 2 Projects

Substation & Mitigation Method	Pros	Cons
Lakeside Original Proposal: Raise & rebuild at existing location New Proposal: Relocate to new site	• Mitigates impacts stemming from unavailability of adjacent property as originally planned (complexities to design and construction sequencing due to small site). • Reduces construction risk (no buildings to remove or abatement necessary at new site). • Eliminates need for service contingencies. • New substation at 101 N. Park Street would be a traditional design, improving operations and maintenance aspects of the station. • Marginal cost savings from filing estimate with joint execution of distribution and transmission projects (approx. $0.6M), however avoids costlier option of performing these projects at existing site ($168.3M combined estimate at existing site vs. $141.5M combined estimate at new site).	• Adds some complexity due to integration of distribution and transmission projects.
Orange Valley Original Proposal: Raise & rebuild at existing location New Proposal: Relocate and consolidate 69kV/4kV on a single property	• ES 2 Project cost decreased from initial estimate of $26.6M to $21M. • Eliminates need for 69kV ring bus and 69kV transmission lines by consolidating to single site, resulting in savings of $15M-$20M. • Eliminates need for service contingencies.	• Adds some complexity due to integration of distribution and transmission projects.

Substation & Mitigation Method	Pros	Cons
	• Sharing of common site costs (fencing, grading, etc.) split between ES 2 Project (15%) and 69kV Project (85%) results in cost efficiencies.	
Constable Hook Original Proposal: Raise & rebuild at existing location New Proposal: Eliminate existing station and construct new station that supports new capacity needs in area and allows future elimination of Bergen Point substation	• New station addresses identified new load growth, station age/condition at Bergen Point, and flood risk at Constable Hook. • Existing Constable Hook circuits are very close to the new site, rearrangements can improve reliability at low cost. • No service contingencies required. • For Bergen Point, saves an estimated $16.2M compared with alternative of rebuilding and converting the existing Bergen Point substation from 26/4kV to 69/13kV.	• Adds some complexity due to integration of distribution and transmission projects.

As indicated in **Table 7**, there are multiple benefits identified for each of the mitigation changes proposed at Lakeside, Orange Valley, and Constable Hook, including offering cost efficiencies by combining work and reducing the risk of execution for each project by eliminating the requirement for service contingencies. The common downside to the mitigation changes across these projects was the marginal increase of complexity encountered with projects that have both distribution and transmission components. While having jointly executed transmission and distribution projects can gain cost efficiencies (e.g., having a common project management team for both projects, cost sharing among common site costs, etc.), it naturally adds a layer of complexity from the interdependencies on the separate projects (e.g., if work on the transmission project must be completed prior to certain distribution project work, or vice-versa, it presents the risk to the latter activities that the predecessor activities are not completed in time to support the overall project schedule). A well-planned project with a capable project management team can avoid or mitigate these risks associated with executing two interrelated projects, while also realizing the cost efficiency opportunities available.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g., installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 8 – ES 2 Costs of Removal as of September 30, 2020 below itemizes the charges to COR for the third, second and first quarters of 2020, the fourth quarter of 2019 and total Energy Strong COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the Energy Strong program through September 30, 2020.

Table 8 – ES 2 Costs of Removal as of September 30, 2020

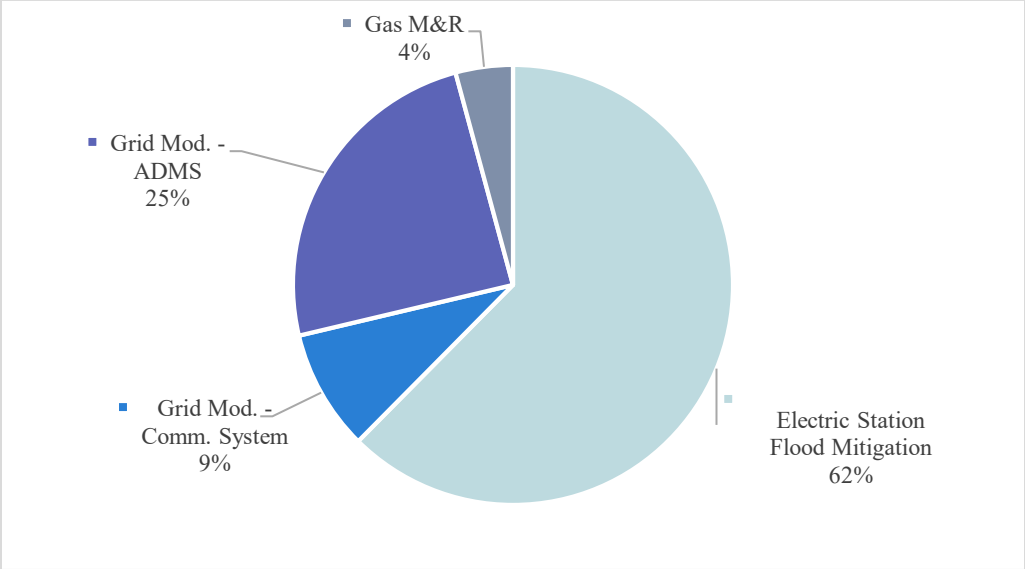
Subprogram	Q4 2019 COR	Q1 2020 COR	Q2 2020 COR	Q3 2020 COR	Total COR
Electric Station Flood Mitigation	**$0**	**$67,332**	**$468,989**	**$294,089**	**$830,410**
Contingency Reconfiguration	**$431,030**	**$616,752**	**$624,595**	**$250,228**	**$1,922,605**
Grid Modernization – Communications	**$0**	**$0**	**$1,495**	**$3,384**	**$4,879**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$431,030**	**$684,084**	**$1,095,079**	**$547,701**	**$2,757,894**

COR charges during the third quarter of 2020 decreased from the second quarter by 50%. Electric Station Flood Mitigation COR decreased by 37% due to the removal of a significant portion of the wiring for the Market Street project during the second quarter. Contingency Reconfiguration COR for the third quarter decreased 60% from the second quarter as a result of correspondingly more preparation work (removing poles, conductors, etc.) done in the second quarter than in the third quarter in support of recloser installation and commissioning.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

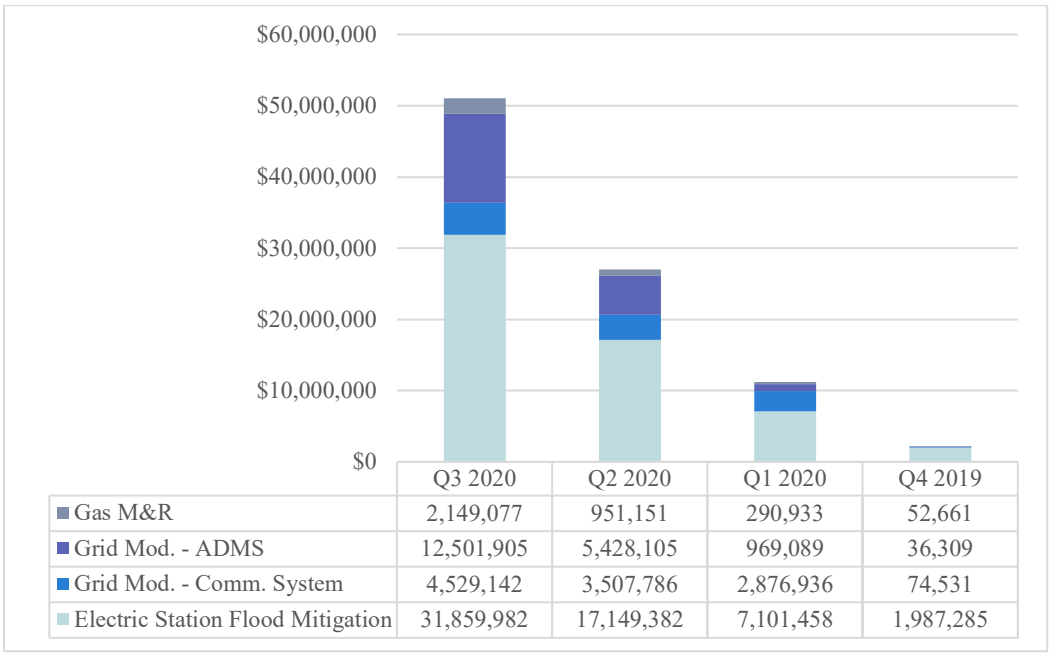
As of September 30, 2020, the Energy Strong CWIP balance was $51.0 million, compared to $27.0 million as of June 30, 2020. The largest components of September 30, 2020 CWIP were the elimination and conversion of the 4kV circuits at Market Street ($10.7 million) and Ridgefield substations ($6.5 million), and work associated with the ADMS ($12.5 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2020** below.

Figure 1 – ES 2 CWIP as of September 30, 2020



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2020



	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas M&R	2,149,077	951,151	290,933	52,661
Grid Mod. - ADMS	12,501,905	5,428,105	969,089	36,309
Grid Mod. - Comm. System	4,529,142	3,507,786	2,876,936	74,531
Electric Station Flood Mitigation	31,859,982	17,149,382	7,101,458	1,987,285

Transfers from CWIP to plant in service have totaled $3.6 million as of September 30, 2020, which came from Grid Modernization projects. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the third, second and first quarters of 2020, the fourth quarter of 2019, and total Energy Strong AFUDC accrued to date, is shown below in **Table 9 – ES 2 AFUDC as of September 30, 2020**.

Table 9 – ES 2 AFUDC as of September 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total AFUDC
Electric Station Flood Mitigation	$9,887	$62,618	$191,807	$377,009	$641,321
Contingency Reconfiguration	$0	$0	$0	$0	$0
Grid Modernization – Communications	$225	$14,752	$60,073	$43,496	$118,546
Grid Modernization - ADMS	$96	$7,092	$28,474	$103,228	$138,890
Electric Stipulated Base	$0	$0	$0	$11,413	$11,413
Gas M&R Station Upgrades	$254	$2,590	$8,465	$19,385	$30,694
Total	$10,462	$87,052	$288,819	$554,531	$940,864

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2020, based on data as of September 30, 2020, the recalculated weighted average AFUDC accrual rate (6.96%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the third quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for Energy Strong projects during the third quarter of 2020 increased significantly over AFUDC accrued during the second quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2020 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 10 – ES 2 Overhead Allocations as of September 30, 2020** are the allocated overhead costs charged to ES 2 projects for the third, second and first quarters of 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 10 – ES 2 Overhead Allocations as of September 30, 2020

Subprogram	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total Overhead Allocations
Electric Station Flood Mitigation	$286,953	$1,648,117	$3,560,216	$3,890,087	$9,385,373
Contingency Reconfiguration	$3,415,460	$4,692,085	$3,055,700	$3,350,239	$14,513,484
Grid Modernization – Communications	$12,074	$345,720	$548,017	$561,011	$1,466,822
Grid Modernization – ADMS	$10,603	$116,442	$91,786	$105,563	$324,394
Electric Stipulated Base	$0	$0	$0	$155,112	$155,112
Gas M&R Station Upgrades	$15,287	$52,836	$68,257	$78,452	$214,832
*Total**	$3,740,376	$6,855,199	$7,323,975	$8,140,465	$26,060,015

**-Note: total figures may not fully align due to rounding.*

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2020 were costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2020, PSE&G experienced a Major Event on August 4-13, 2020 stemming from a State of Emergency that was declared immediately ahead of Tropical Storm Isaias crossing the

region and bringing heavy winds and rain to the area. Tropical Storm Isaias resulted in significant impacts to PSE&G's service territory, including over 800,000 customers experiencing extended service interruptions. **Table 11 – August 4-13, 2020 Major Event** indicates the restoration progress made on these service interruptions during the recovery efforts.

Table 11 – August 4-13, 2020 Major Event

Date (status as of 9AM)	Cumulative Customers Restored	Percentage of Customers Restored
August 5, 2020	377,709	49%
August 6, 2020	576,615	72%
August 7, 2020	666,990	83%
August 8, 2020	727,780	91%
August 9, 2020	751,464	94%
August 10, 2020	757,633	94%
August 11, 2020	766,748	96%
August 12, 2020	778,584	97%
August 13, 2020	797,077	99%
Total	803,026	100%

The outside plant damage resulting from Tropical Storm Isaias included over 12,000 locations comprised of tree damage, pole damage, transformer damage, line damage, and related impacts. This Major Event also resulted in 10 substations being shut down (one of which was shut down a second time during restoration efforts), none of these substations is part of the Electric Station Flood Mitigation subprogram of either the original Energy Strong Program or the current ES 2 Program, additionally none of these substations experienced damage or flood intrusions as a result of Tropical Storm Isaias. The IM received PSE&G's report on the performance of its Energy Strong and ES 2 Program investments from this Major Event, which shows the System Average Interruption Duration Index (SAIDI) for the affected circuits. This information is reproduced as follows in **Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments**.

Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	**0.53760**
ALD 8026	0.07735	0.05740
BAO 8003	0.00193	**0.24119**
BEF 8013	0.02065	**0.75490**
BEF 8015	0.00433	**0.10078**
BEF 8016	0.01430	**0.79704**
BEM 8001	0.00675	**0.01779**
BEN 8012	0.22864	0.15087
BEN 8015	0.01246	**0.09879**
BEN 8016	0.01934	0.00153
BRU 8011	0.04127	**0.17136**
BRU 8012	0.01648	**0.29860**
CAS 8001	0.02438	**0.83779**
CED 8011	0.05594	**2.00873**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
CED 8016	0.07119	**2.65822**
CED 8021	0.10724	**0.25793**
CIN 8005	0.04256	**0.15680**
CIN 8032	0.32648	**1.21326**
CIN 8033	0.14578	0.06644
CIN 8043	0.18459	0.00432
CLF 8012	0.00401	**0.29500**
CLF 8013	0.00064	**0.18687**
CLF 8023	0.00895	**0.10659**
CLK 8022	0.06677	**0.20949**
CLK 8024	0.01526	**0.26509**
CON 8001		0.00000
CRX 8003	0.07703	0.02497
CUT 8006	0.59550	0.06186

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
CUT 8010	0.49117	0.00000
DAY 8002	0.03617	**0.24408**
DFD 8041	0.20440	**0.28663**
DVB 8013	0.00455	0.00016
EAT 8011	0.09890	**2.20796**
EAT 8022	0.08703	**0.14950**
FAW 8022	0.03342	0.02998
FAW 8026	0.00902	**0.83953**
FED 4004		**0.00577**
GBK 8021	0.06208	0.02153
GBK 8022	0.01054	**0.27631**
GET 4009	0.08973	**0.09359**
HAT 8012		**0.10390**
HAT 8023	0.01869	**0.09183**
HAT 8035	0.04291	**0.11367**
HAW 8032	0.22973	**0.33843**
HID 8043	0.06432	**0.11773**
HID 8044	0.08229	**1.21633**
HNC 8015	0.15427	**0.09234**
HNC 8021	0.02280	0.00358
HNC 8024	0.43454	0.01301
HOM 8001	0.06027	0.01298
JAC 8021	0.00477	**0.08572**
JAC 8023	0.05394	**0.65765**
JAC 8043	0.09794	**0.15996**
KIL 8023		0.00000
KIL 8024	0.01504	0.00244
KIL 8031		**0.11829**
KIL 8034	0.44870	0.03134
KIL 8041	0.02511	0.00000
KIL 8044	0.03622	**0.04250**
KIN 8015	0.00194	**1.39884**
KIN 8022	0.01206	**0.56080**
KUL 8022	0.00371	**1.84145**
KUL 8023	0.00582	**0.23170**
KUS 8004	0.00500	**0.32039**
KUS 8042	0.07830	**0.15411**
KUS 8045	0.02505	**0.06255**
LAF 8013	0.00125	**0.07663**
LAU 8021	0.44101	0.13512
LAU 8023	0.82844	0.01479
LAU 8025	0.02009	0.01410
LAU 8034	0.60195	0.04268
LAU 8035	0.29567	0.14706
LAW 8014	0.03705	**0.48862**
LAW 8016	0.14895	0.01929
LCE 8003	0.15926	0.05434
LCE 8032	0.30801	0.13079
LCE 8043	0.10606	**0.45190**
LCE 8046	0.01692	0.00753
LEO 8006	0.07368	**0.14976**
LEO 8032	0.00287	**0.72771**
LEO 8043	0.07891	**2.20942**
LEV 8002	0.06064	0.05044
LEV 8006	0.23842	**0.57946**
LEV 8012	0.25318	**0.32241**
MAD 8015	0.15514	0.00167
MAD 8031	0.45221	0.08238
MAI 8013	0.05318	**0.84551**
MAR 8006	0.06359	0.00000
MAR 8017	0.45014	**0.68220**
MAY 8024	0.00558	**0.09533**
MDF 8012	0.58371	**0.88377**
MDF 8023	0.26488	0.09510
MEA 8012		**0.04784**
MON 8003	0.27132	0.10203
MTL 8013	0.02134	**0.24147**
NBS 8011	0.01516	0.08749
NED 8015	0.09467	**0.13141**
NED 8024		0.00000
NEW 8014	0.01839	**0.05537**
OAK 4004	0.05636	**0.20790**
OAK 4008		**0.24635**
PLI 8003	0.00215	**1.26948**
POH 8021	0.07655	0.00619
RFL 8032	0.12446	**0.15639**
RFL 8034	0.04180	**0.97069**
SDH 8023	0.00860	**0.03903**
SDH 8026	0.01685	**0.15920**
SDH 8031	0.01726	0.01387
SDH 8034		**0.07454**
SMV 8013		**0.00592**
SMV 8021		0.00000
SMV 8023	0.01943	0.00120
SPF 8012	0.78752	**1.81747**
SUN 8022		**0.02479**
TNY 4001	0.02964	0.00638
TUR 8015	0.00704	**0.33184**
WAV 4018	0.02277	**0.79233**
WEW 8011	0.18034	**3.48139**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
WEW 8025	0.00255	**0.00665**
WEW 8033	0.03506	**0.08274**
WFL 8041	0.14394	**0.76889**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
WOR 8021		0.00000
**-SAIDI calculations are in minutes.*		

In the circuit data above, the bolded figures designate the circuits where performance during this Major Event was worse than the 5-year Major Event average SAIDI for the circuit; in addition, blank cells indicate no outage in the 5-year window, while "0.00000" indicates an outage, but the value is beyond five decimal points. As indicated above, a substantial amount of the affected circuits experienced outages beyond the 5-year Major Event average. This performance is reflective of the severity of the storm, which in terms of the 803,026 customers impacted was the third largest storm in PSE&G's history (behind only Hurricane Sandy, with 2,012,612 customers impacted, and Hurricane Irene with 872,942 customers impacted).

In response to comments received on the IM's draft 2020 Third Quarter Report, a comparison of the average CAIDI and SAIFI of circuits impacted by Tropical Storm Isaias is provided in **Table 13 – Tropical Storm Isaias Average Circuit Performance**. This **Table 13** compares the affected circuits from this Major Event by circuits improved during the original Energy Strong Program, circuits improved during ES 2 prior to this Major Event, and circuits not improved by either the original Energy Strong Program or ES 2.

Table 13 – Tropical Storm Isaias Average Circuit Performance

	Average SAIFI during Tropical Storm Isaias	Average CAIDI during Tropical Storm Isaias
Circuits Improved as part of the original Energy Strong Program	0.0005	1,231.47
Circuits Improved as part of the ES 2 Program*	0.0004	1,633.75
Other Circuits not part of either Energy Strong Program	0.0004	1,550.23
**-Circuits improved prior to the start of this Major Event on August 4, 2020*		

This Tropical Storm Isaias Major Event is compared to prior Major Events with similar numbers of customers impacted in **Table 14 – Tropical Storm Isaias Comparable Major Events**.

Table 14 – Tropical Storm Isaias Comparable Major Events

Storm End Date	Major Event Description	Customers Impacted	SAIDI*
9/3/2011	Hurricane Irene	872,492	454.51
8/13/2020	Tropical Storm Isaias	803,026	313.01
11/6/2011	Wet Snowstorm	636,898	380.52
3/19/2010	Nor'easter Storm	607,403	300.01
**-SAIDI calculations are in minutes.*			

As shown in **Table 14**, the SAIDI results from Tropical Storm Isaias compared to similar pre-Energy Strong Major Events demonstrate improved restoration times. This is particularly evident in the relatively close SAIDI results from Tropical Storm Isaias and the March 2010 Nor'easter Storm, despite Tropical Storm Isaias affecting nearly 200,000, or 32%, more customers.

In response to comments received on the IM's draft 2020 Third Quarter Report, additional information on the circuit-level performance of Energy Strong/ES 2 investments in the Major Events compared in **Table 14** has been included in **Table 15 – Tropical Storm Isaias Comparable Major Events Circuit-Level Performance**. Note that many of the circuits listed in **Table 15** were not impacted by each of these four Major Events, with the blanks in the table reflect no outage for a given circuit in the corresponding Major Event.

Table 15 – Tropical Storm Isaias Comparable Major Events Circuit-Level Performance

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	*Major Event SAIDI**			
ALD 8015	0.0004	0.1056	0.0963	0.53760
ALD 8026	-	0.8265	0.9628	0.05740
BEM 8001	-	0.0555	-	0.01779
BEN 8012	0.0344	1.7619	0.0252	0.15087
BEN 8015	0.0326	0.9115	-	0.09879
BRU 8011	-	-	0.012	0.17136
BRU 8012	0.4574	0.2228	0.2629	0.29860
CAS 8001	-	1.4604	-	0.83779
CED 8011	0.8668	0.0379	1.754	2.00873
CED 8016	0.8873	0.029	0.4095	2.65822
CED 8021	0.3964	-	-	0.25793
CIN 8032	0.0007	-	-	1.21326
CIN 8043	0.1052	0.0618	-	0.00432
CLF 8012	-	0.0838	0.3021	0.29500
CLF 8013	0.048	0.0198	0.0482	0.18687
CLF 8023	-	0.048	-	0.10659
CLK 8022	-	0.2108	-	0.20949
CON 8001	0.0052	-	-	0.00000
CRX 8003	0.0041	-	-	0.02497
CUT 8006	0.0069	-	-	0.06186
DAY 8002	0.0753	0.2237	-	0.24408
DFD 8041	-	0.5275	-	0.28663
EAO 4023	-	0.0585	0.2581	0.81003
EAT 8011	0.2677	0.1536	0.5189	2.20796
EAT 8022	0.0859	-	0.1279	0.14950
FAR 4006	-	-	0.8247	0.12767
FAW 8022	-	0.0459	0.4234	0.02998
GBK 8021	-	1.4263	-	0.02153
GBK 8022	-	0.0252	0.0432	0.27631
HAT 8012	0.4581	0.1317	0.1638	0.10390
HAT 8023	0.0733	-	0.0219	0.09183

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	*Major Event SAIDI**			
HAT 8035	0.255	1.7015	0.0885	0.11367
HAW 8032	0.0171	0.1088	0.245	0.33843
HNC 8015	-	0.0174	-	0.09234
HNC 8021	-	-	0.0172	0.00358
HNC 8024	-	0.21	0.8303	0.01301
HOM 8032	-	0.2088	0.3644	0.01298
JAC 8021	0.0357	-	-	0.08572
JAC 8023	0.0288	0.0072	0.1368	0.65765
JAC 8043	-	-	0.4851	0.15996
KIL 8023	-	0.0872	-	0.00000
KIL 8024	0.0538	0.0618	-	0.00244
KIL 8034	-	0.0799	-	0.03134
KIL 8041	-	0.0676	-	0.00000
KIL 8044	-	0.1195	-	0.04250
KIN 8015	-	1.3535	0.178	1.39884
KIN 8022	2.0138	0.1997	1.2249	0.56080
KUL 8023	0.0014	-	0.0884	0.23170
KUS 8004	-	0.1003	0.0199	0.32039
KUS 8042	0.0002	0.8528	-	0.15411
KUS 8045	1.6032	0.3397	0.1158	0.06255
LAU 8021	0.0046	0.0114	4.3783	0.13512
LAU 8023	-	-	0.7065	0.01479
LAU 8025	0.0257	1.2566	0.1612	0.01410
LAU 8034	-	0.1055	0.9157	0.04268
LAU 8035	-	-	0.2887	0.14706
LAW 8016	0.0998	1.266	0.0014	0.01929
LCE 8003	0.0213	0.0657	-	0.05434
LCE 8032	0.1052	0.1621	0.0438	0.13079
LCE 8043	-	0.0231	0.0206	0.45190
LCE 8046	-	0.9558	-	0.00753
LEO 8006	0.0848	0.1848	0.2159	0.14976
LEO 8032	0.6277	0.6999	2.0718	0.72771
LEO 8043	0.1952	0.6377	2.5768	2.20942
LEV 8002	0.0811	-	-	0.05044
LEV 8006	0.2888	0.2704	0.0043	0.57946
LEV 8012	0.0929	0.1373	-	0.32241
MAD 8015	0.0864	-	-	0.00167
MAD 8031	0.0014	-	-	0.08238
MAI 8013	0.9225	0.1033	0.4569	0.84551

Circuit	Mar. 2020 Nor'Easter	Sep. 2011 Hurricane Irene	Nov. 2011 Wet Snow Storm	Aug. 2020 Tropical Storm Isaias
	*Major Event SAIDI**			
MAR 8017	-	1.6707	-	0.68220
MAY 8024	0.2847	-	0.15	0.09533
MDF 8012	-	0.125	-	0.88377
MDF 8023	-	0.3549	-	0.09510
MEA 8012	0.0045	0.0672	-	0.04784
MNT 4010	0.0232	0.7827	1.0713	0.06828
MON 8003	-	0.364	-	0.10203
MTL 8013	-	0.0339	0.0073	0.24147
NBS 8011	-	0.5399	0.1007	0.08749
NED 8015	0.0822	0.7023	0.5621	0.13141
NED 8024	-	1.1162	0.3146	0.00000
NEW 8014	0.2358	0.8618	2.0776	0.05537
OAK 4004	0.0052	-	0.4166	0.20790
OAK 4008	-	-	0.5203	0.24635
PLI 8003	-	-	0.0094	1.26948
RFL 8032	0.0134	0.0158	0.7329	0.15639
RFL 8034	-	-	0.0482	0.97069
SDH 8023	-	0.3303	-	0.03903
SDH 8026	1.8938	1.8557	0.0426	0.15920
SDH 8031	0.0135	0.4626	-	0.01387
SDH 8034	0.0008	0.3125	-	0.07454
SMV 8013	-	1.7671	0.0198	0.00592
SMV 8021	-	0.4698	-	0.00000
SMV 8024	-	2.0881	-	0.00120
SPF 8012	-	1.527	0.1048	1.81747
SPF 8022	0.0522	0.0842	2.4832	0.02479
TNY 4001	-	-	0.0968	0.00638
TUR 8015	-	0.0522	2.606	0.33184
WAV 4018	-	0.3968	-	0.79233
WEW 8011	-	2.5084	2.4866	3.48139
WEW 8025	0.0264	0.1207	-	0.00665
WEW 8033	1.6317	-	2.5859	0.08274
WFL 8041	-	-	0.1619	0.76889
WOR 8021	0.0163	-	-	0.00000
**-SAIDI calculations are in minutes.*				

2. Prior Major Events

As noted in the IM's 2020 Second Quarter Report, PSE&G experienced a Major Event on June 3-7, 2020 stemming from a derecho and severe thunderstorms that primarily affected its Southern Division. These

series of storms led to 257,209 PSE&G customers experiencing service interruptions, with 246,075 of those customers located in the Southern Division. The IM 2020 Second Quarter Report provided the detailed circuit-level performance during this Major Event and in response to questions raised by the IM, PSE&G has provided the IM with additional information on the performance of Energy Strong/ES 2 investments. **Table 16 – Performance of Energy Strong/ES 2 Investments in Q2 2020 Major Event** below reproduces parts of the information originally provided in the IM 2020 Second Quarter Report, specifically identifying those circuits involved in the Major Event that were improved through investments made in either the original Energy Strong Program or the current ES 2 Program.

Table 16 – Performance of Energy Strong/ES 2 Investments in Q2 2020 Major Event

Circuit	5-Year Major Event Average SAIDI*	Q2 2020 Major Event SAIDI*	Q2 2020 Major Event SAIDI Explanation
CIN 8032	0.32648	1.13907	The history for CIN 8032 is spread over eight different events with an average storm SAIDI (34) approximately one-third of the June 2020 event (90). As such, response to these individual events on average would be shorter. In addition to the significantly larger scale of the June 2020 event, the outage was caused by a whole tree failure, which takes longer to restore due to the tree clearing required before service can be restored.
CLK 8022	0.06677	0.21086	The history for CLF 8022 is three low customer count fuse jobs (<70 customers) along with one tree related outage. The June 2020 event SAIDI was driven by a tree related outage on the mainline (578 customers) which required a tree crew to remove the tree before restoration.
KUS 8004	0.00500	0.03236	KUS 8004 experienced three fuse events (average customers of 60) over the course of three smaller storm events. The June 2020 outage was a fuse event (110 customers) caused by a tree failure. Given the scale of the event, this 110-customer job would have been lower priority as compared to jobs with higher customer counts, and thus the outage would have a longer duration. Tree removal would have increased restoration time as well.
LAW 8014	0.03705	1.01225	The history for LAW 8014 is based primarily on a tree limb on the mainline during a much smaller storm event. June 2020 event had five different tree damage locations including one with a broken pole. Scale of the damage significantly higher when compared to history.
MAD 8015	0.15514	0.95230	The history for MAD 8015 includes eight events, five lower count fuse jobs and three mainline jobs of various causes. The June 2020 event SAIDI was primarily due to a section three outage. The scale of the storm event would have delayed this restoration as jobs with higher customer counts (i.e., full circuit lockouts) would have gone first.
MDF 8023	0.26488	0.54601	The history for MDF 8023 is comprised of seven events over three different storms with tree issues being the primary outage driver. The June 2020 events was two whole tree failures. The five-year average history lowers the SAIDI result compared to the single event.
**-SAIDI calculations are in minutes.*			

As indicated in **Table 16**, the circuits with Major Event performance worse than the five-year average from the June 2020 Major Event were primarily the result of lengthier outages during this Major Event resulting from downed trees along with a couple of the circuits having low customer counts and thus had lower priority in the restoration efforts over higher customer circuits that were impacted.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of September 30, 2020 is provided below in **Table 17 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2020**.

Table 17 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Sep. 2020		KO		C						IS		CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020			KO							C					IS				CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Sep. 2020		KO							C					IS		CO			
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Sep. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019				KO				C										IS	CO (Q2)
	Sep. 2020	*Schedule Under Development**																		
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020			KO		C									IS			CO		
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Sep. 2020			KO					C	OS		CO								
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020			KO											C			IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020					KO										C				IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Sep. 2020			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Sep. 2020			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Sep. 2020		KO						C					IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Sep. 2020			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Sep. 2020			KO			C												IS	CO (Q2)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Sep. 2020		KO												C			IS		CO (Q2)

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Lakeside Avenue project had a schedule previously developed, but due to the proposed mitigation method change that contemplates relocating the substation, the schedule is now being revised and updated.**

A summary of the subprogram status as of the end of the third quarter of 2020 is provided below **Table 18 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2020**.

Table 18 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	13	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia; Market Street; Meadow Road; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment POs	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	14	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 18** above, **Table 19 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2020** summarizes the planned activities for each project during the fourth quarter of 2020, including any carryover of activities from earlier periods.

Table 19 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2020

Station	Upcoming Activities for Q4 2020	Carryover Activities from Q3 2020
1. Academy Street	• Electrical construction start • Switchgear delivery to site • 90% estimate completion	• None
2. Clay Street	• Vendor drawings received for final switchgear arrangement • Detailed engineering start	• License and permit package submitted

Station	Upcoming Activities for Q4 2020	Carryover Activities from Q3 2020
3. Constable Hook	• Remains in planning/origination stages	• Remains in planning/origination stages
4. Hasbrouck Heights	• Constructability review • Civil and electrical drawings issued for construction (IFC)	• None
5. Kingsland	• Switchgear delivery to Ridgefield 13kV site (as contingency switchgear, planned to be used for Kingsland following Ridgefield 13kV completion)	• None
6. Lakeside Avenue	• Project kickoff • A/E purchase order issued • License and permit design start	• Transitioning from planning/origination stages
7. Leonia	• Switchgear delivery to site • Phase 1/contingency electrical purchase order issued • Phase 3 civil and electrical drawings IFC	• None
8. Market Street	• Civil demolition construction purchase order issued • 90% estimate completion	• License and permit package submitted
9. Meadow Road	• No major activities	• None
10. Orange Valley	• Release key drawings for detailed engineering design	• Transitioning from planning/origination stages
11. Ridgefield 13kV	• Phase 1 civil, controls, and electrical drawings IFC	• Civil contingency construction completion
12. Ridgefield 4kV	• Railroad permission to proceed received • Complete outside plant underground civil construction	• None
13. State Street	• Civil construction purchase order issued	• None
14. Toney's Brook	• 70% estimate completion • Civil construction purchase order issued	• None
15. Waverly	• Civil and electrical drawings IFC • Vendor drawings received for final switchgear controls • Civil construction out for bid • Major licenses and permits issued	• None
16. Woodlynne	• Constructability review • Civil and electrical construction purchase orders issued	• Civil and electrical drawings IFC

The current project estimates, including base and R&C amounts, is shown below in **Table 20 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020**. **Table 20** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend and percentage of actuals to estimate as of the end of the third quarter of 2020, and the forecasted in-service date.

Table 20 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Conceptual	$9,900,000	$1,900,000	$11,800,000	$9,972,315	$1,962,997	17%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$36,589,865	$853,505	2%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$3,894,313	$110,379	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$17,894,211	$857,466	5%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$283,143	3%
6. Lakeside Avenue	Office	$26,800,000	$9,400,000	$36,100,000	$26,800,000	$529,587	2%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$30,442,204	$1,785,366	6%
8. Market Street	Conceptual	$26,700,000	$3,300,000	$30,000,000	$26,658,817	$12,273,747	41%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,298,686	$483,601	5%
10. Orange Valley	Office	$19,700,000	$6,900,000	$26,600,000	$15,967,714	$358,732	1%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$23,086,520	$3,997,875	16%
12. Ridgefield 4kV	Study	$17,600,000	$2,600,000	$20,200,000	$17,320,551	$6,745,565	33%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$596,494	1%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$15,256,600	$510,253	3%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$32,274,121	$1,465,452	4%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$665,906	3%
Subprogram Total		**$311,900,000**	**$73,700,000**	**$385,500,000**	**$327,092,250**	**$33,480,069**	**9%**

Findings & Observations

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with six projects now in construction as of the end of the third quarter of 2020 (up from three at the end of the second quarter of 2020), and the remaining projects

continuing to advance in design and pre-construction activities with the exception of Constable Hook which largely remains in the planning/origination stage.

- While early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on budget. The status of the later projects in this subprogram, and in particular Orange Valley and Constable Hook, will have to closely be followed to ensure the projects are completed within the ES 2 Program window. At this time, the Orange Valley project shows an in-service date of January 2024, however subsequent to the third quarter of 2020, PSE&G has informed the IM that the project team will be examining the potential to shorten durations and/or work activities concurrently to pull the in-service date back into 2023.

1. Academy Street

During the third quarter of 2020, approximately $1.3 million was spent on the Academy Street project compared to a forecast of approximately $860,000, which brought the total spend to approximately $2 million. The variance in third quarter spend was largely driven by earlier permit approval and land clearing that supported construction starting earlier than forecasted. Notable activities completed during the third quarter of 2020 include:

- State permits received;
- Controls drawings IFC; and,
- Electrical construction purchase order issued.

As noted in the IM 2020 Second Quarter Report, the Study level estimate was approved internally at the end of June 2020 with $9.9 million in base, $2.9 million in R&C, for a total estimate of $12.8 million. The prior Office level estimate for Academy Street was $17.0 million in total, with the majority of the $4.2 million reduction to the current estimate attributed to the change in mitigation method from raise and rebuild to relocate. In July 2020, this Study level estimate was approved before the URB.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate lowered the total Academy Street project estimate from the previously approved $12.8 million to $11.8 million, with the reduction driven by a $1.0 million reduction to R&C based on the current risk register for the project.

Construction at Academy Street, which started in July 2020 for non-permit work, has advanced to 25% complete inside plant (100% complete outside plant) as of the end of the third quarter of 2020. The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$150,398	$99,893	$399,935	$1,312,771	$1,962,997	$11,800,000	17%

2. Clay Street

During the third quarter of 2020, approximately $234,000 was spent on the Clay Street project compared to a forecast of approximately $248,000, which brought the total spend to approximately $854,000. Notable activities completed during the third quarter of 2020 include:

- License and permit package issued;
- Project execution plan completed; and,
- Civil and electrical inside plant construction POs issued.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$116,409	$219,707	$283,219	$234,171	$853,505	$42,000,000	2%

3. Constable Hook

Through the end of the third quarter of 2020, the Constable Hook project continued to remain in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed (see related discussion in **Section II.A.3.** and **Section IV.B.**). The actual spend by quarter for Constable Hook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$17,889	$51,758	$32,313	$8,419	$110,379	$5,300,000	2%

4. Hasbrouck Heights

During the third quarter of 2020, approximately $326,000 was spent on the Hasbrouck Heights project compared to a forecast of approximately $346,000, which brought the total spend to approximately $532,000. Notable activities completed during the third quarter of 2020 include:

- Site plan administrative approval received;
- NJDEP approval received; and,
- Vendor drawings received (final switchgear arrangement).

A Covid-19 related delay on the associated Hasbrouck Heights 69kV project has resulted in a delay to the Hasbrouck Heights ES 2 project. This delay shifts the planned start of construction from June to August 2021 and the forecasted in-service date from November to December 2022. The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$149,848	$193,879	$188,045	$325,694	$857,466	$18,000,000	5%

5. Kingsland

During the third quarter of 2020, approximately $27,000 was spent on the Kingsland project compared to a forecast of approximately $42,000, which brought the total spend to approximately $283,000. There were minimal activities performed on this project during the third quarter of 2020.

As noted in the IM 2020 Second Quarter Report, a revised Study level estimate was approved internally at the end of June 2020 with $5.4 million in base, $2.9 million in R&C, for a total estimate of $8.3 million. The prior Study level estimate for Kingsland was $10.0 million in total, with the $1.7 million reduction to the current estimate attributed to a reduction in the switchgear commitment on the project. The current plan and estimate are based on Kingsland utilizing a contingency switchgear from another project that will be available once construction is completed. In July 2020, this revised Study level estimate was

approved before the URB. The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$104,112	$108,286	$43,268	$27,477	$283,143	$8,300,000	3%

6. Lakeside Avenue

The Lakeside Avenue project continued to advance the planning efforts, with the key plans and conceptual drawings progressing during the third quarter of 2020. The forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the original property location for the 69kV and ES 2 projects having contamination risks that resulted in a new potential property location, for which the purchase process is underway (see related discussion in **Section II.A.3.** and **Section IV.B.**). The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$148,943	$172,224	$121,009	$87,411	$529,587	$36,100,000	2%

7. Leonia

During the third quarter of 2020, approximately $1.07 million was spent on the Leonia project compared to a forecast of approximately $1.02 million, which brought the total spend to approximately $$1.8 million. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear controls for switchgear 1 and 2);
- Civil construction commenced; and,
- Electrical construction (contingency) out for bid.

Construction at Leonia, which started in August 2020, has advanced to 15% complete inside plant as of the end of the third quarter of 2020. The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$44,792	$244,323	$424,783	$1,071,468	$1,785,366	$32,200,000	6%

8. Market Street

During the third quarter of 2020, approximately $4.9 million was spent on the Market Street project compared to a forecast of approximately $5 million, which brought the total spend to approximately $12.2 million. Notable activities completed during the third quarter of 2020 include:

- County road crossing permit received;
- Outside plant construction advanced to 45% complete.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate did not change the total Market Street project estimate from the previously approved $30.0 million, however, it did result in an increase to the base estimate (from $24.2 million to $26.7 million) with the primary changes to the base estimate being attributed to:

- Change in T&D surcharge methodology, approved by PSE&G Accounting, +$2.5 million;
- Outside plant soil remediation, +$1.2 million; and,
- Estimate refinement, ($1.2 million).

This net $2.5 million increase in the base estimate was offset by a $2.5 million reduction to R&C based on the current risk register for the project.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$251,193	$1,938,713	$5,144,270	$4,939,571	$12,273,747	$30,000,000	41%

9. Meadow Road

During the third quarter of 2020, approximately $173,000 was spent on the Meadow Road project compared to a forecast of approximately $141,000, which brought the total spend to approximately $484,000. Notable activities completed during the third quarter of 2020 included the issuance of the license and permit package.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$63,128	$142,946	$104,563	$172,964	$483,601	$9,000,000	5%

10. Orange Valley

Through the end of the third quarter of 2020, the Orange Valley project advanced past the initial planning and origination stages (see related discussion in **Section II.A.3.** and **Section IV.B.**), with the kickoff meeting taking place in September 2020 and Burns & McDonnell being awarded the A/E scope. The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$77,029	$96,582	$120,690	$64,432	$358,732	$26,600,000	1%

11. Ridgefield 13kV

During the third quarter of 2020, approximately $3.0 million was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.9 million, which brought the total spend to approximately $4.0 million. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear controls for switchgear 1 and 2);
- Electrical construction purchase order issued (temporary switchgear);
- The temporary 13kV sheltered aisle switchgear was delivered to the site; and,
- The temporary switchgear was set.

Construction at Ridgefield 13kV, which started in June 2020, has advanced to 23% complete inside plant as of the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$205,982	$317,289	$500,475	$2,974,130	$3,997,875	$25,500,000	16%

12. Ridgefield 4kV

During the third quarter of 2020, approximately $3.8 million was spent on the Ridgefield 4kV project compared to a forecast of approximately $6.6 million. The variance in actual versus forecasted spend for the third quarter was predominantly the result of Division accruals not captured by the Division's accrual system in July, the postponement of jack and bore installation under the railway tracks due to not receiving CSX approval and needed permits in time (this work was performed in October 2020). This brought the total spend to approximately $6.7 million.

In September 2020, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate lowered the total Ridgefield 4kV project estimate from the previously approved $21.1 million to $20.2 million. The base estimate increased from $16.8 million to $17.6 million, largely driven by the underground work costs being higher than previously estimated, while the R&C decreased from $4.3 million to $2.6 million based on the current risk register for the project.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 47% complete. The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$143,414	$693,128	$2,134,627	$3,774,395	$6,745,565	$20,200,000	33%

13. State Street

During the third quarter of 2020, approximately $218,000 was spent on the State Street project compared to a forecast of approximately $190,000, which brought the total spend to approximately $596,000. Notable activities completed during the third quarter of 2020 include:

- Site plan submitted and approved by the planning board;
- Civil and electrical drawings IFC;
- State Conservation District permit approved;
- Vendor drawings received (final switchgear controls); and,
- Civil and electrical construction out for bid.

As noted in the IM 2020 Second Quarter Report, the Study level estimate was approved internally at the end of June 2020 with $39.0 million in base, $6.1 million in R&C, for a total estimate of $45.1 million.

The prior Office level estimate for Academy Street was $28.6 million in total, with the majority of the $16.5 million increase to the current estimate attributed to the change in mitigation method from raise and rebuild to relocate. In July 2020, this Study level estimate was approved before the URB. The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$77,950	$128,288	$172,777	$217,839	$596,494	$45,100,000	1%

14. Toney's Brook

During the third quarter of 2020, approximately $96,000 was spent on the Toney's Brook project compared to a forecast of approximately $151,000, which brought the total spend to approximately $510,000. Notable activities completed during the third quarter of 2020 include:

- Vendor drawings received (final switchgear arrangement); and,
- Received planning board approval for site plan.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$211,940	$115,747	$86,315	$96,251	$510,253	$19,700,000	3%

15. Waverly

During the third quarter of 2020, approximately $651,000 was spent on the Waverly project compared to a forecast of approximately $429,000, which brought the total spend to approximately $1.5 million. The third quarter forecast to actual variance was driven largely by Pre-Phase 1 construction work (place-install cast in place hand holes) starting in September to support Phase 1 construction in October 2020. Notable activities completed during the third quarter of 2020 include:

- Civil and electrical drawings IFC;
- License and permitting package submitted; and,
- Start of Pre-Phase 1 construction.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$103,748	$355,706	$355,335	$650,662	$1,465,452	$35,400,000	4%

16. Woodlynne

During the third quarter of 2020, approximately $101,000 was spent on the Woodlynne project compared to a forecast of approximately $153,000, which brought the total spend to approximately $666,000. Notable activities completed during the third quarter of 2020 include:

- Received planning board approval for the site plan;
- Contingency plan completed; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$110,982	$240,418	$213,482	$101,024	$665,906	$19,400,000	3%

B. Contingency Reconfiguration

During the third quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers. However, severe weather in July and August (including Tropical Storm Isaias) resulted in approximately half a month of work being missed. PSE&G has worked with the Divisions to identify resources to recover these delays and was able to resume work quickly after the restoration efforts were completed with the current expectation that installation and commissioning of reclosers will regain the planned progress in 2021. The third quarter of 2020 also saw minor inventory issues, with the receipt of 4kV reclosers delayed due to Covid-19 impacts to the manufacturer. To mitigate any potential impacts from that delay, PSE&G reallocated its recloser inventory such that the Metro Division (with the largest 4kV population and smallest 13kV population of the Divisions) received all the 4kV reclosers in PSE&G's inventory until additional equipment was received in September. There is no overall impact anticipated from this temporary inventory shortage as PSE&G was able to adjust its plan to continue to advance the work in the subprogram. **Table 21 – ES 2 Recloser Status as of September 30, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year-end targets and current status of engineering, installation, and commissioning.

Table 21 – ES 2 Recloser Status as of September 30, 2020

Type	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
		Q3 Qty.	*Total*	*Q3 Qty.*	*Total*	*Q3 Qty.*	*Total*
13kV	800	44	638	129	546	283	413
4kV	179	37	300	27	65	44	55
Total	979	81	938	156	611	327	468

As shown in **Table 21**, engineering continues to stay comfortably ahead of construction, allowing PSE&G flexibility in selecting which projects to initiate construction on and allows the subprogram progress to continue, while the commissioned units more than doubled during the third quarter as previously installed units were completed. Compared to the 2020 year-end targets, as of the end of the third quarter of 2020, the engineering was near the year-end target, approximately two-thirds of the targeted reclosers have been installed and approximately half have been commissioned.

The Fuse Saver installations are planned to begin later in 2020 with a pilot program that installs Hmc radios in the Fuse Savers to support communication on the device when there is an event. PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure the

devices work as intended, with the pilot program contemplating installation of 57 single-phase units and 18 two-phase units by the end of 2020. PSE&G's initial plan was to commence the pilot program in September 2020, however it encountered firmware issues from the vendor that delayed the start of this pilot program until the fourth quarter of 2020.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 22 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2020**.

Table 22 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2020

Scope & Division		Forecasted Completion Date
Reclosers	Central	11/30/2021
	Metro	11/30/2021
	Palisades	12/31/2021
	Southern	12/31/2021
Fuse Savers	Central	7/31/2023
	Metro	7/31/2023
	Palisades	7/31/2023
	Southern	7/31/2023

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2020 are presented in **Table 23 – ES 2 Contingency Reconfiguration Costs as of September 30, 2020**.

Table 23 – Contingency Reconfiguration Costs as of September 30, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$2,801,328	$11,694,777	$21,497,603	54%
	Metro	$2,231,431	$3,576,616	$1,946,751	$1,950,122	$9,704,920	$21,087,215	46%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$2,602,224	$10,734,341	$20,250,897	53%
	Southern	$2,081,220	$4,003,537	$2,098,258	$2,764,372	$10,947,387	$23,561,179	46%
Fuse Savers	Central	$9,970	$29,667	$48,444	$73,176	$161,258	$13,118,198	1%
	Metro	$7,557	$15,498	$28,339	$41,921	$93,315	$10,863,516	1%
	Palisades	$7,468	$15,259	$16,336	$20,878	$59,941	$9,243,291	1%
	Southern	$9,792	$21,458	22,973	$35,596	$89,818	$12,276,134	1%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$10,289,616**	**$43,485,758**	**$131,898,033**	**33%**

The current forecast of approximately $131.9 million shown in **Table 23** for the Contingency Reconfiguration subprogram represents an approximate $18 million reduction from the forecast as of the end of the second quarter of 2020. The change in the Contingency Reconfiguration subprogram forecast was predominantly driven by the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing.

Findings & Observations:

- Recloser installations fell behind the third quarter target primarily due to weather-related impacts. However, PSE&G continued to advance work particularly through pole installations and commissioning of recloser installed earlier with Hm radios.

- PSE&G was able to mitigate the impacts from the delayed reclosers shipment through adjusting near-term plans to reallocate the available inventory in a way that allowed the Divisions to continue to progress the installations.
- While the Fuse Saver pilot program had its start delayed due to vendor firmware issues, this is an example of why the pilot program was developed as it allows minor issues like these firmware issues to be resolved prior to commencing the full effort.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

C. Grid Modernization – Communication System

As reported in the IM 2020 Second Quarter Report, in June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. During the third quarter of 2020, PSE&G conducted a service territory coverage assessment of the network, which found less than 1/10 of 1% of the service territory to have service below the coverage threshold. This assessment also identified four of 30 in-building partitions were below the service threshold, as a result PSE&G boosted the in-building signal at these locations, which had no cost impact to the subprogram.

As also reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the third quarter of 2020, 34 retrofit installations took place against a forecast of 35 installations. The installations were specifically targeted by PSE&G and the Divisions based on a prioritization of the devices that have the most communication problems, once the majority of these identified devices are retrofitted, the prioritization will switch to by circuit. The initial retrofit reclosers prioritized also includes those that PSE&G's IT department was working with Verizon to replace existing copper lines with fiber. By prioritizing these devices, it allows PSE&G to gain cost efficiencies by retrofitting these devices in conjunction with the other work and avoids the need to return to these devices at a later time.

On the fiber scope, which includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network, 41 installation projects and 12 cutovers have been identified, with the first batch of installations expected to be placed in-service during the fourth quarter of 2020 and the cutovers to be completed early in 2021. During the third quarter of 2020, the initial six fiber projects commenced construction while an additional five had design packages issued. These 11 fiber projects represent the projects selected by PSE&G for 2020, an additional 14 projects have been preliminarily identified for the 2021 efforts.

The Grid Modernization – Communication System subprogram costs through the end of the third quarter of 2020 are presented in **Table 24 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2020**.

Table 24 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2020

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
R	Central	$0	$50,613	$150,958	$201,053	$402,264	$7,959,730	5%

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
	Metro	$0	$44,164	$139,069	$214,848	$398,081	$6,795,675	6%
	Palisades	$0	$44,164	$138,485	$216,524	$399,173	$6,943,433	6%
	Southern	$0	$46,901	$145,479	$198,307	$390,687	$8,475,961	5%
Fiber	Central	$1,691	$133,115	$272,307	$660,034	$1,067,147	$7,479,617	14%
Fiber	Metro	$1,457	$109,382	$299,876	$419,162	$829,877	$5,792,227	14%
Fiber	Palisades	$1,582	$194,451	$520,068	$403,443	$1,119,544	$4,087,557	27%
Fiber	Southern	$4,731	$65,721	$139,575	$120,011	$330,038	$3,266,163	10%
Fiber	Cutovers	$0	$0	$0	$40,869	$40,869	$930,560	4%
Wireless Network		$74,306	$1,525,801	$2,353,604	$1,508,075	$5,461,786	$7,390,016	74%
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$5,106,396**	**$11,563,896**	**$59,120,939**	**20%**

Findings & Observations:

- Retrofit recloser installations continued in the third quarter of 2020, but as previously noted PSE&G made a strategic decision for prioritizing radio installations on new reclosers (being installed as part of the Contingency Reconfiguration subprogram). PSE&G is also prioritizing the retrofit installations for locations where cost efficiencies can be gained by scheduling the radio retrofit work to be performed with related non-ES 2 work.
- The first six fiber projects commenced during the third quarter of 2020, with the other five fiber projects that comprise the 2020 scope having design underway in advance of construction starting in the fourth quarter of 2020.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, including as previously reported in the second quarter of 2020, the signing of the Open Systems International Inc. (OSII) contract. The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application. During the third quarter of 2020, kickoff meetings were held on the OMS scope and six business process workshops, 10 initial interface design workshops, and 24 requirements review workshops were conducted. Other activities during the third quarter of 2020 included the delivery of the first phase of hardware to OSII and the purchase of additional platform hardware (Dell servers and storage devices for Newark and Edison). This additional hardware has an overall cost impact of approximately $1.2 million, however, PSE&G has reviewed the current ADMS estimate and the forecast remains at $40.4 million. The final ADMS release is currently forecasted to go live during the fourth quarter of 2022.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2020 are presented in **Table 25 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2020**.

Table 25 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2020

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Forecast	% of Actuals to Forecast
Actuals						
$36,213	$925,689	$4,430,542	$6,970,572	$12,363,016	$40,374,822	31%

Findings & Observations:

- The activities to date on the subprogram continue to be primarily planning activities, including continuing to have workshops with the software vendor and operations.
- Several workshops occurred during the third quarter, which despite the challenges posed by Covid-19 restrictions, were completed without issue.
- Despite the Covid-19 related challenges, the IM has found nothing to date that would jeopardize the subprogram being completed on time. The current forecast, including the $1.2 million in additional hardware purchased during the third quarter of 2020, exceeds the Stipulation amount allocated for this subprogram by approximately $5.4 million. While this subprogram on its own would likely exceed the Stipulation budget, per the Stipulation, PSE&G has the ability to reallocate funds amongst the electric subprograms of the ES 2 Program in part to address the *"many variables associated with this type of work that make it difficult to precisely budget each subprogram project initiative."*[1] With the overall electric portion of the ES 2 Program under budget, this mechanism may be implemented by PSE&G in the future to address the currently forecasted overrun in this Grid Modernization – ADMS subprogram. The IM will continue to closely monitor the costs in this regard.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] As reported in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards. Based on the current study level estimate for the life cycle upgrades (detailed below), the current view shows that approximately 80% of these funds will be applied towards life cycle upgrades, with the remainder going towards the electric outside plant higher design and construction standards. As noted in the IM 2020 Second Quarter Report, this current ratio is driven by the approval of the four life cycle stations, including risk and contingency funds, to allow their completion within the ES 2 Program window. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction standards. The outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the

[1] Energy Strong 2 Stipulation, paragraph 22, September 11, 2019
[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 26 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2020**.

Table 26 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$177,808	1%	11/2/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$408,931	2%	9/28/2022
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$503,189	2%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$383,581	2%	12/16/2022
**-Reflects the in-service date of the last major asset (e.g., switchgear), certain activities may take place after this date to support the final in-service date (i.e., when all customers are cutover).*							

Details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

The Hamilton substation was originally constructed in 1953 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines, two 69/4kV transformers, and eight 4kV feeders. From 2008-2017, the 4kV supply circuits at Hamilton have experienced 67 extended outages and seven momentary outages, for a total duration of nearly 308 hours. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- License and permitting design commenced.
- Detailed engineering commenced.
- Major equipment purchase order issued.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$177,808	$177,808	$18,200,000	1%

2. Paramus

The Paramus substation was originally constructed in 1958 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of three 69kV lines supplying a six-breaker ring bus, with three 69/4kV transformers, and 12 4kV feeder rows. From

2008-2017, the 4kV supply circuits at Paramus have experienced 116 extended outages and 20 momentary outages, for a total duration of nearly 1,044 hours. Black & Veatch was awarded the A/E scope for this project. The life cycle upgrades contemplate upgrading equipment and protection schemes including replacing the old electromechanical relays with modern digital relays to increase the reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- Major equipment purchase order issued.
- License and permitting design commenced.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$408,931	$408,931	$20,200,000	2%

3. Plainfield

The 4-kV Switchgear at the Plainfield substation is in poor condition. A significant portion of the 4-kV equipment at the station is still original from when the substation constructed in 1958 and the metal clad switchgear has rusted and must be addressed. In addition, all of the 4-kV distribution feeders and Tie Feeder currently run through the same manhole and conduit system, which presents the possibility of extended outages to the customers supplied from Plainfield Substation in the event of a cable or splice failure that results in collateral damage to adjacent feeders. This station currently consists of three (3) 69-kV lines supplying a Six (6) - Breaker GIS Ring Bus, with three (3) 69 / 4-kV transformers, twelve (12) 4-kV feeders, one (1) 4-kV Tie Feeder, and two (2) 2.7MVA. Black & Veatch was awarded the A/E scope for this project. Notable activities conducted during the third quarter of 2020 included:

- Project kickoff meeting held.
- License and permitting design commenced.
- Detailed engineering commenced.
- Major equipment purchase order issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$503,189	$503,189	$22,600,000	2%

4. Woodbury

The Woodbury substation was originally constructed in 1954 with a significant portion of its current 4kV equipment being the original equipment at the substation. The station currently consists of four 26kV lines, three 26kV bus section breakers, three 26/4kV transformers, three transformer 4kV breakers, and 12 4kV feeders with voltage regulators and reactors. From 2008-2017, the 4kV supply circuits at Woodbury have experienced 153 extended outages and eight momentary outages, for a total duration of nearly 883 hours. Burns & McDonnell was awarded the A/E scope for this project. The life cycle upgrades contemplate replacing the old electromechanical relays with modern digital relays to increase the

reliability, resiliency, and life span of the substation. Notable activities conducted during the third quarter of 2020 included:

- Major equipment purchase order issued.
- License and permitting design commenced.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$0	$0	$0	$383,851	$383,851	$18,700,000	2%

Findings & Observations:

- The four electric stipulated base substation life cycle projects progressed in planning and preparation efforts during the third quarter of 2020 with activities such as permitting preparation and issuance of purchase orders for major equipment.
- While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards. Funding these four projects fully allows them to be completed within the ES 2 Program window, in addition PSE&G excepts excess funds from the Electric Station Flood Mitigation subprogram (currently forecasted approximately $60 million under its Stipulation amount) to be reallocated to the life cycle station upgrades as provided in the Stipulation.

F. Gas M&R Station Upgrades

Through the end of the third quarter of 2020, preliminary design continued on each of the Gas M&R stations. **Table 27 – ES 2 Gas M&R Summary Status as of September 30, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates. As indicated in **Table 16**, there continues to have been minimal spend to date on the subprogram, with the actual spend primarily related to initial planning and preliminary design efforts.

Table 27 – ES 2 Gas M&R Summary Status as of September 30, 2020

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$351,353	2%	Jan 2023
2. Central*	Office	$12,800,000	$6,900,000	$19,700,000	$356,592	2%	Jan 2023
3. East Rutherford	Office	$10,300,000	$5,600,000	$15,900,000	$317,447	2%	Jan 2023
4. Mount Laurel	Study	$9,400,000	$2,400,000	$11,800,000	$241,187	2%	Dec 2022
5. Paramus*	Office	$12,900,000	$7,000,000	$19,900,000	$307,130	2%	Jan 2022
6. Westampton	Study	$8,300,000	$2,100,000	$10,400,000	$544,675	5%	Dec 2021
Subprogram Total		**$65,600,000**	**$35,400,000**	**$101,000,000**	**$2,118,383**	**2%**	**Jan 2023**

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
*-Included in the Stipulated Base.							

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects and current activities such as preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

1. Camden

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering and other planning activities, including the award of the A/E contract to Burns & McDonnell in July 2020 following the re-bid of this scope after the original selected firm did not agree with PSE&G's terms and conditions for material procurement. For the remainder of 2020, planned activities include continued engineering development, including a 3D model review in October 2020 and preparation and issuance of the licensing and permitting package in November 2020, and the issuance of purchase orders for the major equipment (building, heaters, pipes, scrubber, valves, and regulators) in December 2020. The Study level estimate for the Camden project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$13,326	$46,691	$83,499	$207,837	$351,353	$15,400,000	2%

2. Central

As noted above, the primary work to date on the Gas M&R subprogram has been continuing with preliminary engineering, including the prior award of the A/E contract to Odin EPC, LLC, and other planning activities. During the third quarter of 2020, a site survey was completed, and a coordination meeting conducted with IT and Security. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 to support the licensing and permitting packages being submitted in January 2021. The Study level estimate for the Central project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$6,869	$45,048	$109,557	$195,119	$356,592	$19,700,000	2%

3. East Rutherford

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. During the third quarter of 2020, the conceptual design for the project was approved and a coordination meeting was held with IT and Security. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 to prepare issued for bid drawings to be issued in January 2021. The Study level estimate for the East Rutherford project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$9,010	$37,747	$111,526	$159,165	$317,447	$15,900,000	2%

4. Mount Laurel

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to J.F. Kiely Service Co., LLC, and other planning activities. During the third quarter of 2020, detailed schedule development resulted in the initially planned in-service date on the milestone schedule changing from January 2022 to October 2022. In September 2020, the Study level estimate for Mount Laurel was approved by the URB. This updated estimate decreased the total project estimate from $17.4 million to $11.8 million (including a $1.9 million reduction in the base estimate and a $3.7 million reduction in risk and contingency) and was based upon a further refined plan and scope and updated risk evaluation. For the remainder of 2020, engineering efforts are planned to continue with detailed design commencing in October 2020 and all drawings (civil, electrical, instrumentation, and mechanical) expected to be issued for review (IFR) in November 2020. Construction is currently anticipated to begin in March 2022.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$5,965	$27,804	$74,737	$132,680	$241,187	$11,800,000	2%

5. Paramus

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to EN Engineering, LLC, and other planning activities. During the third quarter of 2020, the conceptual design was approved for the project and a 3D drawing review was held in September 2020. A coordination meeting with IT and Security was also conducted during the third quarter of 2020. For the remainder of 2020, engineering efforts are planned to continue with the preparation of issued for review drawings in December 2020 to support their release in January 2021. The Study level estimate for the Paramus project is planned to be submitted to the URB in December 2020.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$8,842	$37,793	$91,247	$169,249	$307,130	$19,900,000	2%

6. Westampton

As noted above, the primary work to date on the Gas M&R subprogram has been continuing preliminary engineering, including the prior award of the A/E contract to NVS, Inc., and other planning activities. During the third quarter of 2020, detailed schedule development resulted in the initially planned in-service date on the milestone schedule changing from July 2021 to October 2021. In September 2020, geotechnical borings were completed at the site and the Study level estimate for Westampton was approved by the URB. This updated estimate reduced the total project estimate from $12.7 million to $10.4 million (including a $2.3 million reduction of risk and contingency) and was based on a further refinement of the scope and an updated risk evaluation. For the remainder of 2020, engineering efforts are planned to continue in support of the issuance of the major equipment POs in November 2020 and the submittal of the licensing and permitting package. Construction is currently anticipated to begin in January 2021 and be completed in October 2021.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Total to Date	Estimate	% of Actuals to Estimate
Actuals						
$8,395	$40,839	$180,947	$314,493	$544,675	$10,400,000	5%

IV. Additional Information Following the End of the Third Quarter of 2020

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the third quarter of 2020, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2020 Third Quarter Report.

A. Decisions Recorded After the Third Quarter of 2020

Grid Modernization – Communication System Subprogram: Fiber Scope

On October 29, 2020, PSE&G recorded a Record of Decision to perform a full review of the fiber requirements and the status of all PSE&G substations and operations centers to verify communication needs.

The ES 2 filing included the installation of fiber to approximately 31 distribution substations not currently on the PSE&G transmission fiber system, seven operations centers, and the connection of approximately 133 substations with existing fiber at the substation. PSE&G noted to the IM that as PSE&G has continued to modernize the Distribution system outside of the ES Program, the fiber needs at substations and operations centers have also changed. PSE&G has advised that some locations no longer require fiber due to being scheduled for an upgrade, rebuild, or elimination, others now require fiber, and some have been transitioned to fiber communications.

Alternatives Considered:

1. Install fiber communication to all locations identified in the filing.
2. Perform a full review of the fiber requirements and status of all PSE&G substations and operational centers to verify fiber communication needs.

As PSE&G began to undertake the ES 2 Program, PSE&G noted to the IM that as PSE&G's Distribution grid evolved so did the list of locations that require a high-speed reliable, redundant, and resilient communication network, all a major component of the Grid Modernization subprogram. The overall network will use wireless and fiber technology that will enable communications with a broad range of electric distribution field assets and customer equipment. This ROD is noted to only be for the substation fiber and operations fiber install.

The full review contemplated under this ROD is as follows:

1. Remove Substations and Operation Centers where fiber installation is no longer required or are currently communicating via PSE&G fiber backbone.
2. Place on hold any Substation or Operation Center where the future status of the station is not clearly defined. Once a final determination is made the status will be revised.
3. Identify potential candidates for inclusion in the fiber install program. To be considered, the location needs to meet the following criteria:
    a. Known future status-not subject to being eliminated/upgraded in the near-term
    b. Location is operationally enabled to expand and utilize PSE&G's Fiber Backbone
    c. Operationally Critical (key communication hub during Storm & Emergency Events)

d. Has existing or will support future SCADA [supervisory control and data acquisition] communications.

As of the date of the ROD, eight locations were removed from the scope, six were approved and added to the scope and five proposed locations were under review. Since that time, three additional locations were removed from scope, which PSE&G noted will be reported in a subsequent amendment to the first ROD document.

The IM inquired to PSE&G if the cost of the full review of all PSE&G substation fiber requirements were captured within the subprogram costs. PSE&G responded that the cost of the PSE&G substation fiber requirement review was not directly captured in the subprogram costs. PSE&G noted that these types of scope review activities are part of the standard job function of PSE&G's Asset Management Group. These employees were noted to primarily charge Surcharge or operations & maintenance (O&M) orders depending on the specific activity being performed.

The IM also inquired as to the criteria in which the stations were added or removed from the list provided within the ROD (e.g., which element listed under "Decision Made" contributed to the changes in the table). PSE&G provided the IM with a table of the approved locations, locations removed from the scope, and the reasons for inclusion or elimination.

Five of the approved proposed locations were noted as a station not subject to elimination or upgrade in the near term and is operationally driven to utilize PSE&G's fiber backbone and is SCADA-enabled. The other location was noted to also be operationally critical as a key communication hub during storm and emergency events. For the locations eliminated, nine were noted to be scheduled for upgrade in the near future and the other two noted to have an existing connection to the PSE&G fiber backbone and was moved to the cutover program.

Findings and Observations

- The review and vetting process is being put in place to maximize the value of the ES 2 Program budget allocated to fiber initiatives and to ensure the Program aligns with the current communication needs.
- The IM finds that PSE&G's decision to undertake the review is appropriate and will enable that the projects included in the fiber scope will maximize the efficiency of the network to meet the filing scope of the Grid Modernization subprogram.
- The IM finds the process for determining whether to add or eliminate the location from the scope is reasonable.
- The proposed budget for the scope of work contemplated within the 2018 filing was $24 million (fiber portion of Grid Modernization). The fiber scope to be performed at the approved selected locations is currently forecasted at approximately $21.5 million, suggesting an opportunity to potentially include additional projects.

B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes

On October 5, 2020, the State of New Jersey Division of Rate Counsel (Rate Counsel) responded to PSE&G's notice of change in mitigation method by objecting to PSE&G implementing the changes without further clarification, citing to the Stipulation at paragraph 24. Rate Counsel noted that there were remaining questions regarding these PSE&G proposed changes including whether they will likely deliver the same benefits to customers or are appropriate under the circumstances. Rate Counsel requested that all

activities cease related to these changes in mitigation until such time as additional information and clarification is provided by PSE&G.

The IM received and reviewed the discovery requests and responses relating to this issue (including BPU Staff requests S-INF-0001 through S-INF-0003 and Rate Counsel requests RCR-INF-0001 through RCR-INF-0006). The responses provide requested information concerning the original and revised transmission and distribution project costs (including whether land and demolition costs are captured in the estimates), timing of when specific factors leading to the decision to change the mitigation method at these substations were identified by PSE&G, and other related information such as the environmental status of the proposed new Orange Valley site and if the new Lakeside/101 N. Park Street substation will incorporate loads from other substations.

The IM also received a presentation on the proposed mitigation method changes at Constable Hook, Lakeside Avenue, and Orange Valley from PSE&G dated October 22, 2020. This presentation provided additional information on the proposed changes including maps of the current and newly proposed sites and the drivers and benefits offered by the proposed changes.

On January 6, 2021, PSE&G wrote to both the BPU and Rate Counsel stating that the plans and estimates provided in the Company's initial ES 2 filing were based on the "best information available at the time" noting that as projects shift into the implementation phase, changes in project estimates and "as-filed" mitigation methods may be necessary as contemplated in the Stipulation. Relative to the prior change in mitigation method at State Street, PSE&G stated that in this limited circumstance, the Company will seek recovery of additional cost over the filing estimate in its next rate case as opposed to through the ES 2 accelerated recovery mechanism. With respect to Lakeside Avenue, Orange Valley, and Constable Hook, PSE&G stated that all requested information regarding the changes have been identified and provided to both the BPU Staff and Rate Counsel. PSE&G also stated that it is moving forward with the changes as discussed in part to benefit from the identified efficiencies, which will result in savings and increased reliability for customers.

On January 19, 2021, Rate Counsel responded to PSE&G's January 6, 2021 letter indicating Rate Counsel did not oppose PSE&G's decision to seek recovery of the increased cost for State Street in its next rate case as opposed to ES 2. Rate Counsel also stated that it cautioned PSE&G that the Company would be proceeding on the changes to Constable Hook, Lakeside, and Orange Valley at its own risk in accordance with paragraph 39 of the Stipulation noting that prudency of projects undertaken in ES 2 Program "would not take place prior to or in connection with the rate adjustments established herein."

In its January 19, 2021 letter to PSE&G, Rate Counsel noted it had specific concerns regarding the changes in mitigation method to the Constable Hook substation. Rate Counsel believes that the changes to the Constable Hook project should be excluded from the ES 2 Program since based on the information provided by PSE&G, the Company's justification for the change in mitigation method at Constable Hook to accommodate the new load at the former Military Ocean Terminal appears inconsistent with the Board's requirements for an Infrastructure Investment Program (IIP) under N.J.A.C. 14:3-2A.1. Rate Counsel stated that the BPU's regulations limit the use of the IIP to "non-revenue producing utility plant and facilities that enhance safety, reliability, and/or resiliency." Rate Counsel noted that although PSE&G identified Bergen Point as a life cycle station due to its age, that it is not part of the ES2 Program since Class A Stations with indoor 4kV equipment have been classified as lower risk than the Class C outdoor stations. Although combining the substation projects to accommodate the anticipated load growth and addressing life cycle issues will result in lower costs for the Company overall, Rate Counsel believes that it should be undertaken through traditional base recovery and not the ES 2 Program.

On February 19, 2021, PSE&G, Rate Counsel, and BPU Staff participated in a conference call to discuss Rate Counsel's objections. During this call, PSE&G explained the proposed change for the Constable Hook substation as consistent with its response to discovery request S-PSEG-ENG-002, including that any costs associated with addressing load growth would be tracked separately under a base capital project and not recovered through the ES 2 accelerated recovery mechanism. However, due to the complexities associated with this project, it became apparent that PSE&G would not be able to complete the Constable Hook project within the ES 2 Program window. Accordingly, PSE&G informed the parties of its intent to remove the Constable Hook substation from the ES 2 Program and instead perform this flood mitigation work as a base capital project. PSE&G also noted its intent to use the funds allocated for Constable Hook to perform additional life cycle station work in accordance with the terms of the Stipulation.

The IM will report on the status of this change as it becomes formalized through PSE&G's processes and as the additional life cycle station work is identified and selected.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2020 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

11 MAY 2021

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	Reference Page 1, Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2020 a. What is attributed to the forecasted cost of the Contingency Reconfiguration subprogram decreasing from $150.8 million in the Independent Monitor's ("IM's") Q2 2020 Report to $131.9 million in the IM's Q3 2020 Report? b. What is attributed to the forecasted cost of the Gas Metering and Regulation ("M&R") Station Upgrades subprogram increasing from $65.6 million in the IM's Q2 2020 Report to $76.2 million in the IM's Q3 2020 Report?	a. The change in the Contingency Reconfiguration subprogram forecast from the second to third quarter of 2020 was predominantly driven by the removal the removal of 117 13kV reclosers and 109 4kV reclosers. This was the result of a detailed assessment of each circuit to determine the current status reflecting updated system plans and changes or other work done subsequent to the ES 2 filing. While outside of the third quarter of 2020, the IM also points out that the Contingency Reconfiguration subprogram forecast increased to approximately $162.8 million as of the end of 2020 based on a placeholder for additional reclosers currently being reviewed and an increase in the cost per unit of the fuse savers based on the actual cost trend of the pilot program. b. The change in the Gas M&R forecast was predominantly driven by an increase to the forecast for the Central M&R project from $12.8 million as of the second quarter of 2020 to $23.9 million as of the third quarter of 2020. This forecast was validated and incorporated into the project's Study level estimate that was approved at $30.0 million (including R&C) in December 2020. The increase was driven by higher construction costs based on the engineer's 50% estimate, additional buildings and equipment required for the refined design, and additional project management, engineering, and licensing and permitting support not included in the prior estimate.	**Sections I. and II.B.**
S-INF-2	Reference Page 2, Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2020 Please provide the total forecasted costs of each Electric Station Flood Mitigation project.	The total forecasted costs for each Electric Station Flood Mitigation project (as of the end of the third quarter of 2020) has been incorporated into **Table 2**.	**Table 2**
S-INF-3	Reference Page 8 Regarding the Orange Valley project scope change, please describe how the allocation of common site costs was	The common site costs allocation between the ES 2 and 69kV Orange Valley projects was determined by PSE&G based on the ratio of each project's Study level estimated cost of station equipment and structures	**Section II A.3.**

ID #	Question/Comment	IM Response	Report Changes
	determined (15% going towards the Energy Strong II project and 85% going towards the transmission project).	to the total estimate cost of station equipment and structures for both projects, which was then rounded to the nearest 5%.	
S-INF-4	Reference Page 15, Table 9 – ES 2 AFUDC as of September 30, 2020 Please reconcile the Allowance for Funds Used During Construction recorded within the Electric Station Flood Mitigation subprogram during Q2 2020 ($191,807) with the same value as reported in the IM's Q2 2020 Report ($83,234).	The IM 2020 Second Quarter Report incorrectly reported the AFUDC for the Electric Station Flood Mitigation subprogram as $83,234 (the June 2020 AFUDC amount) rather than the $191,807 figure shown in this report (which represents the total AFUDC for Q2 2020 on that subprogram). In the IM's review of this item, it was determined other Q2 2020 AFUDC figures had similar issues where the June 2020 amount rather than the full second quarter amount was depicted and the Q1 2020 AFUDC figures were correct for each subprogram, but did not distinguish between the two Grid Modernization subprograms and totaled slightly off the correct amount. A corrected IM 2020 First and Second Quarter Reports are being issued to address these errors in the prior reports.	**Table 9**
S-INF-5	Reference Page 18, Table 12 – Q3 2020 Major Event Performance of Energy Strong/ES 2 Investments Please provide the average System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") of circuits improved by Energy Strong and Energy Strong II projects during Tropical Storm Isaias and compare to the average SAIFI and CAIDI of unimproved circuits.	The requested comparison has been incorporated into the discussion on this Major Event in the new **Table 13**.	**Section II.D.1. / Table 13**
S-INF-6	Reference Page 19, Table 13 – Tropical Storm Isaias Comparable Major Events Please compare the System Average Interruption Duration Index ("SAIDI") of circuits improved by Energy Strong and Energy Strong II projects during Tropical Storm Isaias to the SAIDI of these same circuits during Hurricane Irene, Wet Snowstorm (11/6/2011), and the March 2020 Nor'Easter Storm.	The requested comparison has been incorporated into the discussion on this Major Event in the new **Table 14**.	**Section II.D.1. / Table 14**
S-INF-7	Reference Pages 24-25, Table 18 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2020 Please confirm that the Electrical Station Flood Mitigation subprogram base spending estimate should total $311.9 million (rather than $309.4 million) and risk and contingency should total $73.7 million (rather than $77.2 million).	Table 18 in the draft report (now **Table 20** in this final draft) had incorrect total amounts for the base and R&C figures, the correct amounts ($311.9 million base, $73.7 million R&C, and $385.5 million total) have been updated in this final report.	**Table 20**
S-INF-8	Reference Page 26, Electric Station Flood Mitigation Projects – Hasbrouck Heights	The associated Hasbrouck Heights 69kV project encountered Covid-19 related delays stemming from an equipment vendor not being able to	No change

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Hasbrouck Heights substation project, pleas provide additional details about the COVID-19 related delay which shifted construction from June 2021 to August 2021.	travel to the site, which delayed installation of equipment on the 69kV project. The Hasbrouck Heights ES 2 project requires installation of the 69kV project first, which resulted in the construction shifting on the ES 2 project from June 2021 to August 2021.	
S-INF-9	Reference Page 28, Electric Station Flood Mitigation Projects – Market Street With respect to the Market Street substation project, what is attributed to the base estimate increasing from $24.2 million in Q2 2020 to $26.7 million in Q3 2020?	As the Market Street substation project advanced from a Study level to Conceptual level estimate, the primary changes to the base estimate were: • Change in T&D surcharge methodology, approved by PSE&G Accounting, +$2.5 million • Outside plant soil remediation, +$1.2 million • Estimate refinement, ($1.2 million) The net $2.5 million increase to the base estimate was offset by a reduction in R&C, resulting in no overall change to the project's estimate.	**Section III.A.8**
S-INF-10	Reference Page 34, Table 22- ES 2 Grid Modernization – Communication System Costs as of September 30, 2020 Regarding the Grid Modernization – Communications subprogram, what is attributed to the forecasted cost of fiber cutovers decreasing from $6,735,000 in the IM's Q2 2020 Report to $930,560 in the IM's Q3 2020 Report?	The difference between the fiber cutover forecast from Q2 2020 to Q3 2020 is attributed to the Q2 2020 forecast ($6,735,000) representing the full cutover funding as approved at the onset of the ES 2 Program. As the subprogram has developed, PSE&G has identified that fiber estimates have come in higher than initially planned and with more projects available than there is funding for, PSE&G is maintaining flexibility in allocating funds within this subprogram and will continue to update its forecast based on the current cutover projects selected by the subprogram.	No change
RCR-IM-1	With reference to pages 1 and 31, please explain the "minor inventory issues" for the Contingency Reconfiguration subprogram.	The lead-time on recloser orders is typically approximately four months. The recloser manufacturer experienced Covid-19 impacts and shipping issues that delayed a shipment of additional 4kV reclosers by approximately one month. To mitigate potential impacts, PSE&G reallocated its existing recloser inventory such that Metro Division with the largest population of 4kV circuits and smallest population of 13kV circuits received all 4kV reclosers in the inventory. During this time, the subprogram was also impacted by weather that limited installations. No overall lasting impacts to the subprogram have resulted from this issue.	No change
RCR-IM-2	With reference to page 2, Table 2, please explain the anticipate slip in schedule for the Clay Street substation and whether the Company experienced permitting delays or project execution plan development delays that contributed to the slip in schedule.	The forecasted in-service date for the Clay Street project changed from December 27, 2022 as of the end of the second quarter of 2020 to January 12, 2023 as of the end of the third quarter of 2020, or a 16-day slip. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands the delay is driven by the development and approval of the	No change

ID #	Question/Comment	IM Response	Report Changes
		licensing and permitting package, including related delays in early 2021 in scheduling a meeting with the Newark planning board due to Covid-19 restrictions.	
RCR-IM-3	With reference to page 2, Table 2, please explain the anticipated slip in schedule for the Kingsland substation and whether this slip is attributable to the change in scope or related to the reduction in switchgear commitment described later on page 27.	The IM draft report incorrectly identified the Kingsland substation has having a Q2 to Q3 schedule slippage, there was no change in the forecasted in-service date for the Kingsland substation during this period. However, the Hasbrouck Heights substation listed above Kingsland in **Table 2** did have a change in the forecasted in-service date from November 18, 2022 as of the end of the second quarter of 2020 to December 2, 2022 as of the end of the third quarter of 2020. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the schedule change was the result of Covid-19 related delays to the associated Hasbrouck Heights 69kV project (see **Section III.A.4.**).	**Table 2**
RCR-IM-4	With reference to page 2, Table 2, please explain the anticipated slip in schedule for the Leonia substation and whether this slip is due to delays in construction.	The forecasted in-service date for the Leonia project changed from November 30, 2022 as of the end of the second quarter of 2020 to December 2, 2022 as of the end of the third quarter of 2020, or a 2-day slip. Because of this extremely small variance, the IM considers this to be normal schedule movement and has not performed additional analysis on the schedule.	No change
RCR-IM-5	With reference to page 2, Table 2, please explain the anticipated acceleration in schedule for Ridgefield 13kV.	The forecasted in-service date for the Ridgefield 13kV project changed from October 19, 2022 as of the end of the second quarter of 2020 to October 7, 2022 as of the end of the third quarter of 2020, or a 12-day advancement to the schedule. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands this schedule advancement is the result of PSE&G reviewing the schedule activities and durations, which resulted in a slight improvement to the overall project schedule.	No change
RCR-IM-6	With reference to page 2, Table 2, please explain the anticipated acceleration in schedule for the Waverly substation.	The forecasted in-service date for the Waverly project changed from December 4, 2023 as of the end of the second quarter of 2020 to November 16, 2023 as of the end of the third quarter of 2020, or a 18-day advancement to the schedule. While this is within the 60-day threshold the IM has used since the original Energy Strong Program to evaluate schedule changes, the IM understands this schedule advancement is primarily the result of the Phase 2 and Phase 3 construction activities advancing approximately two weeks, which also pulled the in-service date forward.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-7	With reference to page 2 and 6 through 8, please provide an explanation to the described property owner issue for the 101 N. Park Location. a. Will this issue cause a change in mitigation strategy for the substation? b. Does the company have another site if the current site location cannot be used?	The 101 N. Park location represents the proposed mitigation change from the original Lakeside Avenue location. There is no present property owner issue at the 101 N. Park site and PSE&G anticipates closing its acquisition of the property in December 2021.	No change
RCR-IM-8	With reference to page 4, please explain why the range in bids is so large for creating a wireless network across the PSE&G service territory.	The primary factor in the range of pricing is based on the spectrum requirements, with the FirstNet option not requiring the purchase of additional spectrum and other vendors having a spectrum cost of up to $156 million. The 5-year estimated O&M costs were also lower with FirstNet.	No change
RCR-IM-9	With reference to page 4, is FirstNet architecture completely separate from the AT&T LTE network also contemplated by the Company?	The FirstNet network is the result of a public-private partnership with AT&T. Essentially, AT&T is responsible for building the network using spectrum dedicated to public safety by the Federal government, which is distinct from AT&T's commercial LTE network.	No change
RCR-IM-10	With reference to page 4, is the $28.7 million the cost for the life of the project? Are there fees to be paid that are not included?	The $28.7 million figure represents the cost to construct the network and does not include operating and maintenance costs.	No change
RCR-IM-11	With reference to page 9, is the transaction still expected to close in April 2021 for the new Orange Valley substation location?	As of the date of this report, the property has not yet closed, but is expected to in April-May 2021.	No change
RCR-IM-12	With reference to page 18, which substations were impacted as a result of Tropical Storm Isaias? What was the damage to those substations?	The substations shut down during this Major Event were: Avenel, Clark, Harts Lane, Hudson Terrace (shut down a second time during restoration efforts), Bordentown, Medford, Montgomery, Mount Holly, Princeton, and, Southampton. None of these substations experienced damage or flood intrusion as a result of Tropical Storm Isaias.	**Section II.D.1.**
RCR-IM-13	With reference to pages 18 and 19, Table 12, please identify the units. Are they minutes or hours?	The SAIDI calculations presented are based on minutes.	**Table 12**
RCR-IM-14	With reference to pages 20 and 21, Table 14, please identify the units. Are they minutes or hours?	The SAIDI calculations presented are based on minutes.	**Tables 14 & 16**
RCR-IM-15	With reference to page 25, will the Orange Valley substation work be completed outside the ES2 timeframe?	As of the end of the third quarter of 2020, the Orange Valley project was forecasted to be completed in January 2024. However, as noted in the report, PSE&G is examining the potential to shorten durations and/or work activities concurrently to pull the in-service date into 2023 (as of	No change

ID #	Question/Comment	IM Response	Report Changes
		the January 2021 schedule, the most recent currently available to the IM, the forecasted in-service date has advanced to December 29, 2023).	
RCR-IM-16	With reference to page 29, please describe the underground work scope increase for Ridgefield 4kV.	There was no scope increase for the underground work; however, following the solicitation of bids from PSE&G's approved list of underground contractors and award going to the lowest bidder after analyzing the technical and commercial bid components, the award of this work was higher than PSE&G initially estimated by approximately $1.0 million.	No change
RCR-IM-17	With reference to page 36, Table 24, are these the worst performing Class A substations? Please confirm that they are all Class A substations.	As discussed in the IM 2020 Second Quarter Report, the four current life cycle station upgrade projects are all Class C substations. In addition, each is one of the 15 stations identified in PSE&G's ES 2 filing as having the highest priority for this scope of work. As part of the planning for the 15 highest priority stations, PSE&G evaluated the project complexity for each location. Given that only a limited number of projects can be completed as part of the Program, PSE&G selected three stations where standard equipment and processes could be utilized to upgrade the stations. The fourth project initially selected (Plainfield) will require special equipment to offload the station due to the property constraints. This equipment and construction process can be utilized for future life cycle projects and this project was selected to develop and refine these procedures.	No change
PSE&G-1	Stipulated Base AFUDC figures are missing from Table 9.	The Electric Stipulated Base AFUDC figures were incorporated into **Table 9**.	**Table 9**
PSE&G-2	The Ridgefield 4kV estimate in Table 18 reflects the Study Level estimate rather than the current Conceptual Level estimate.	The current Conceptual Level estimate for Ridgefield 4kV was incorporated into Table 18 (now **Table 20** in this final draft). The IM also notes that the Ridgefield 4kV discussion in **Section III.A.12.** showed the correct and current $20.2 million estimate.	**Table 20**
PSE&G-3	The Kingsland estimate on page 27 shows the prior Study level estimate rather than the revised Study level estimate.	The revised Study level estimate for Kingsland was incorporated into **Section III.A.5**. The IM also notes that the Kingsland estimate in **Table 20** showed the correct and current $8.3 million estimate.	**Section III.A.5**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2020 FOURTH QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

SEPTEMBER 24, 2021

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Key Decisions 3
B. Program Management 7
C. Cost Assignments 7
D. System Performance 11
III. Project Status 12
A. Electric Station Flood Mitigation 12
B. Contingency Reconfiguration 24
C. Grid Modernization – Communication System 27
D. Grid Modernization – ADMS 29
E. Electric Stipulated Base 30
F. Gas M&R Station Upgrades 33
IV. Additional Information Following the End of the Fourth Quarter of 2020 38
A. Decisions Recorded After the Fourth Quarter of 2020 38
B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes 39

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS

Allowance for Funds Used During Construction ..... AFUDC

Architectural and Engineering ..... A/E

Board of Public Utilities ..... BPU

Construction Work In Progress ..... CWIP

Costs of Removal ..... COR

Distribution Management System ..... DMS

Distributed Energy Resource Management System ..... DERMS

Energy Strong 2 ..... ES 2

Environmental Protection Agency ..... EPA

Gas-Insulated Switchgear ..... GIS

Gas Metering & Regulating ..... Gas M&R

Hazardous Waste Operations and Emergency Response ..... HAZWOPER

Henkels & McCoy ..... H&M

Independent Monitor ..... IM

Issued for Construction ..... IFC

Issued for Review ..... IFR

Liquid Propane Air ..... LPA

Mobile Construction Workforce ..... MCW

Open Systems International Inc. ..... OSII

Outage Management System ..... OMS

Passaic Valley Sewerage Commission ..... PVSC

Per- and Polyfluoroalkyl Substances ..... PFAS

Plain Old Telephone Service ..... POTS

Public Service Electric & Gas ..... PSE&G

Purchase Orders ..... POs

Record of Decision ..... ROD

Risk and Contingency ..... R&C

System Average Interruption Duration Index ..... SAIDI

Transmission & Distribution..... T&D

Utility Review Board..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the fourth quarter of 2020, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and, Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers. Within the other subprograms, the Grid Modernization – Communication System subprogram continued to advance with the initiation of the 2020 fiber projects during the fourth quarter and placing three of the fiber installation projects and five of the fiber cutover projects in-service before the end of the year. The Grid Modernization – ADMS subprogram continued to plan and develop the platform and necessary hardware equipment, while the Gas M&R subprogram continued engineering design and other early project activities such as developing licensing and permitting packages and identification of major equipment/long-lead items. The four stations approved within the life cycle upgrades portion of the Electric Stipulated Base initiated detailed design and continued other planning activities. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2020** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2020

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$21,896,101	$53,945,172	$339,403,267	16%	Jan 2024	$389M
Contingency Reconfiguration	$16,150,287	$59,636,044	$162,806,273	37%	Jun 2023	$145M
Grid Modernization – Communications	$7,656,612	$19,220,506	$59,306,886	32%	Dec 2023	$72M
Grid Modernization – ADMS	$4,120,822	$16,483,837	$40,374,139	41%	Oct 2022	$35M
Electric Stipulated Base	$962,284	$2,436,062	$100,000,000	2%	Dec 2023	$100M
Gas M&R Station Upgrades^	$1,843,109	$3,961,492	$76,815,837	5%	Dec 2023	$101M
Total*	$52,629,214	$155,683,114	$778,706,402	20%	Jan 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects or placeholders for potential additional projects in these subprograms. See **Table 12 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2020

Project	Total Estimate	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$4,374,948	42%	10/25/2021
2. Clay Street	$42,000,000	$995,748	2%	2/6/2023 (↓)
3. Constable Hook	$5,300,000	$115,640	2%	TBD
4. Hasbrouck Heights	$18,000,000	$1,279,782	7%	4/12/2023 (↓)
5. Kingsland	$8,300,000	$313,779	4%	10/4/2023
6. Lakeside Avenue	$47,900,000	$602,937	1%	12/13/2023 (↑)
7. Leonia	$32,200,000	$6,078,171	19%	9/30/2022 (↑)
8. Market Street	$26,900,000	$16,330,794	61%	9/22/2021
9. Meadow Road	$9,000,000	$598,209	7%	9/21/2023
10. Orange Valley	$20,200,000	$439,924	2%	1/24/2024 (↓)
11. Ridgefield 13kV	$25,500,000	$6,438,674	25%	10/13/2022 (↓)
12. Ridgefield 4kV	$20,200,000	$11,382,948	56%	5/28/2021 (↑)
13. State Street	$45,100,000	$739,738	2%	9/23/2022
14. Toney's Brook	$19,700,000	$585,036	3%	4/21/2023
15. Waverly	$35,400,000	$2,564,563	7%	11/8/2023 (↑)
16. Woodlynne	$19,400,000	$1,104,280	6%	10/11/2023 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As indicated in **Table 2**, the projects that have advanced into construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) projects continue to have the highest spend. Additionally, five of the stations (Academy Street, Constable Hook, Lakeside Avenue, Market Street, and Orange Valley) had new estimates approved by the URB in during the fourth quarter of 2020. **Table 2** also shows that nine of the sixteen projects in this subprogram had movement in the forecasted in-service date, with four advancing and five slipping. Of these nine projects, only two (Hasbrouck Heights and Leonia) had movement more than 60 days, which is the threshold the IM applied during the original Energy Strong Program for evaluating changes to the project schedules. The Hasbrouck Heights forecasted in-service date moved from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens Gas-Insulated Switchgear (GIS) installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022. The Leonia forecasted in-service date moved from early December 2022 to late September 2022 based on review of the durations for circuit cutovers and a resulting improvement in durations that allowed the in-service date to advance approximately two months.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget, while schedule challenges, particularly on the Orange Valley substation, will warrant further monitoring to ensure the Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On July 15, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2020 Fourth Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and, rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2020 Fourth Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network – ESII-GM-3	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center – ESII-GM-4	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope – ESII-GM-1	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in **Section II.A.1.** below)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – Communication System	Communication Retrofit of Replacement and non ES-II Units – ESII-GM-2	Reasonable and appropriate *(See **Section II.A.2.** below)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See **Section II.A.3.** below)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling – ESII-FM-1	Reasonable and appropriate *(See **Section IV.A** below)*

1. Electric Station Flood Mitigation – Lakeside Avenue, Orange Valley, and Constable Hook Change in Mitigation Method

As discussed within the IM 2020 Third Quarter Report (Sections II.A.3. and IV.B.), in September 2020, PSE&G formally proposed a change to the mitigation method at Lakeside Avenue, Orange Valley, and Constable Hook from raise and rebuild to relocate. Following an objection from Rate Counsel on the implementation of such mitigation methods changes without further clarification, PSE&G responded to requests from Rate Counsel and BPU Staff for additional information on these proposed changes, which continued to be discussed through the end of 2020. Additional information relative to this decision following the end of 2020 is provided in **Section IV.B.**

2. Communication Retrofit of Replacement and non ES-II Units

The Grid Modernization – Communication System subprogram features the implementation of a new wireless communication network to eliminate PSE&G's reliance on dedicated phone lines ("plain old telephone service", or "POTS") for remote communications. To address the existing reclosers that communicate via POTS lines, PSE&G is retrofitting these devices to allow communication on the new wireless network as part of this subprogram. During the normal course of operations, some of the existing reclosers fail and require replacement, the capital replacement units are budgeted and accounted for each year under Distribution Base Capital blankets and moving forward, and recloser will be commissioned via the new wireless network instead of reconnected to POTS lines. Additionally, several of the new reclosers being installed by PSE&G outside the ES 2 Program either were in stock or purchased during the period shortly after Program approval, these devices will be fitted with new wireless network radios to facilitate communication on the new wireless network.

Before reaching this decision, PSE&G considered the following alternatives:

For replacement of failed units:

1. Install replacement recloser with communication equipment required to operate on the new wireless network.
2. Install replacement recloser on POTS lines and retrofit communication to the wireless network at a later date.

For the cost application of new non-ES 2 recloser units:

1. Remove commissioning and radio costs from the ES 2 Program for any non-ES 2 reclosers installed after the filing was approved.
2. Create a cutoff point for the transitional period as year-end 2020 as to when commissioning costs can be attributed to the ES 2 retrofit initiative.
3. Apply commissioning costs for non-ES 2 reclosers to retrofit accounting for the duration of the ES 2 Program.

For both components of this decision, PSE&G's Grid Modernization – Communication System subprogram team in coordination with PSE&G's Asset Management group determined the appropriate course of action. This saves time and resources by eliminating the additional work of installing the new asset on POTS lines and later retrofitting it. It also establishes more reliable communications than existed on these units. For replacement of failed units, the decision was made to install the replacement reclosers with communication equipment required to operate on the new wireless network. For the cost application of new non-ES 2 recloser units, the decision was made to implement a cutoff deadline of year-end 2020 for when commissioning costs of these units can be applied to ES 2. This decision was based on a recognition that while some of these units were already part of an existing installation roadmap and would meet the intent of the ES 2 filing, however there was a need to establish a hard deadline rather than continue this approach indefinitely.

Both of these aspects of the Grid Modernization – Communication subprogram will be tracked as completed "existing retrofit" units and from a cost accounting standpoint, the guidance shown in **Table 4 – Retrofit Recloser Cost Treatment** will be applied to both scenarios:

Table 4 – Retrofit Recloser Cost Treatment

Scope Category	Scope Description	Accountable Project
Material	New Recloser	Distribution Base Capital Blanket
	Radio & Accessories	ES 2 Grid Modernization – Communication System
Labor	Removal of Defective Recloser	Distribution Base Capital Blanket
	Installation of New Recloser	Distribution Base Capital Blanket
	Commissioning of New Recloser	ES 2 Grid Modernization – Communication System

This cost allocation is intended to isolate the ES 2 labor and material costs that are only related to the preparation and commissioning of the asset for the new wireless network, which is consistent with the activities performed on a typical recloser retrofit in the Grid Modernization – Communication System subprogram. All other costs for these reclosers will be attributed to the appropriate Distribution Base Capital blanket or specific project.

Findings and Observations

- The IM finds that this decision reached by PSE&G appropriately addresses aspects of the Grid Modernization – Communication System subprogram that overlap with routine, non-ES 2 Program work.
- By allowing replacement reclosers not planned as part of the ES 2 Program to be connected to the new wireless network, it allows the benefits of the Program investments to be realized on these devices earlier than it otherwise would be.
- PSE&G's decision to segregate the costs elements of this type of work between ES 2 and base capital provides alignment with the standard recloser retrofits that are part of the subprogram.

3. Market Street Radioactive Soil Testing and Handling

On August 20, 2020, PSE&G recorded a ROD to utilize outside contractors/consultants Henkels & McCoy (H&M) as its OSHA Hazardous Waste Operations and Emergency Response Standard (HAZWOPER) contractor along with Kleinfelder for all spoils testing and monitoring of work areas in the Market Street Project area as part of the scope of work on the Market Street ES 2 Project.

During detailed engineering of the Outside Plant area of the Project, PSE&G discovered that the Market Street substation and a large portion of the Outside Plant area to be replaced (poles) are located within the Environmental Protection Agency (EPA) designated "Study Areas" within Gloucester City to address the potential presence of radioactive soil.

OSHA's HAZWOPER is established to protect workers at hazardous sites. To comply with the OSHA standard, PSE&G does not have appropriately trained internal resources to self-perform these tasks.

Alternatives were considered which included:

1. Provide necessary HAZWOPER training and certification to PSE&G personnel as well as provide the necessary tools, equipment, and procedures to be able to execute the work within the Study Areas with internal resources.
2. Hire suitably qualified contractors who are experienced and equipped to perform excavation and testing in the Study Areas within the required project schedule.

The PSE&G Mobile Construction Workforce (MCW) determined that the internal PSE&G resources were not available to handle excavation of radioactive material. The PSE&G Environmental Projects team also indicated that internal PSE&G resources were not available to perform testing of this type and scale. As a result, PSE&G Procurement recommended utilizing H&M to perform HAZWOPER excavations since they were already under contract for this type of work, under a previously competitive bid Master Service Agreement. PSE&G noted that conducting a new bid event for these services would likely result in higher rates than contained in the Master Agreement holding favorable rates to PSE&G and would likely delay the substation project by two to three months.

PSE&G indicated that Kleinfelder was chosen for testing and monitoring due to their experience with radioactive contamination, familiarity with associated EPA and U.S. Army Corp of Engineers projects in the Gloucester City area, along with their reliable service on recent PSE&G contamination projects.

The EPA reviewed and approved PSE&G's project plan for the work in the Study Areas and agreed to dispose of any radioactive material that is removed. PSE&G estimates the incremental cost for soil excavation, testing, and monitoring activities is approximately $1.8 million.

Findings and Observations

- The IM finds that PSE&G appropriately investigated the alternatives and making its decision to retain outside contractor/consultants did so based on obtaining the best pricing for the work to be performed and to reduce the risk of schedule delay.
- By hiring a certified HAZWOPER contractor to perform the excavations for the poles and place sonotubes within the Study Areas, PSE&G MCW crews were able to subsequently install new poles within the sonotubes, avoiding direct exposure to potentially contaminated soils.
- The EPA has already approved PSE&G's plan for the work allowing work to proceed without schedule delay.
- The IM further finds that PSE&G's decision will provide for safety of its own crews and avoid schedule delay that may have resulted if PSE&G had chosen to train its internal personnel for this specific location.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Costs of Removal as of December 31, 2020, below itemizes the charges to COR for each quarter of 2020, total 2020, the fourth quarter of 2019 and total Energy Strong COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through December 31, 2020.

Table 5 – ES 2 Costs of Removal as of December 31, 2020

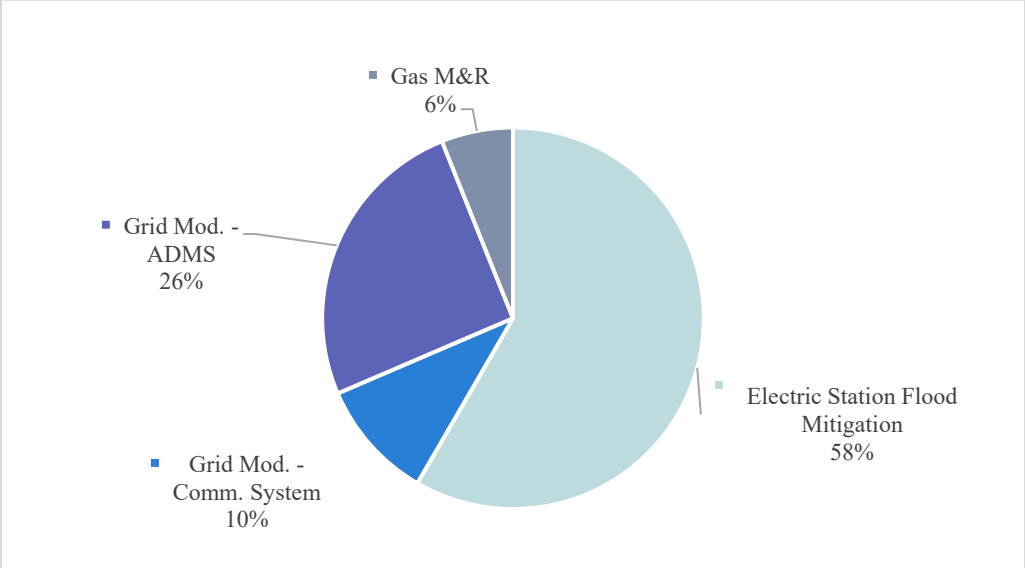
Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total COR
Electric Station Flood Mitigation	$190,735	$294,089	$468,989	$67,332	$1,021,145	$0	$1,021,145
Contingency Reconfiguration	$707,300	$250,228	$624,595	$616,752	$2,198,875	$431,030	$2,629,905
Grid Modernization – Communications	$19,564	$3,384	$1,495	$0	$24,443	$0	$24,443
Grid Modernization - ADMS	$0	$0	$0	$0	$0	$0	$0
Electric Stipulated Base	$0	$0	$0	$0	$0	$0	$0
Gas M&R Station Upgrades	$0	$0	$0	$0	$0	$0	$0
Total	$917,599	$547,701	$1,095,079	$684,084	$3,244,463	$431,030	$3,675,493

COR charges during the fourth quarter of 2020 increased from the third quarter by 68%, primarily due to a higher level of reclosers installations, with the associated pole and conductor removals, in the fourth quarter from the third. The increase in Grid Modernization COR in the fourth quarter of 2020 from the third quarter reflects the removal of existing communications equipment related to the recloser installations, and to removal of equipment in support of the fiber projects.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

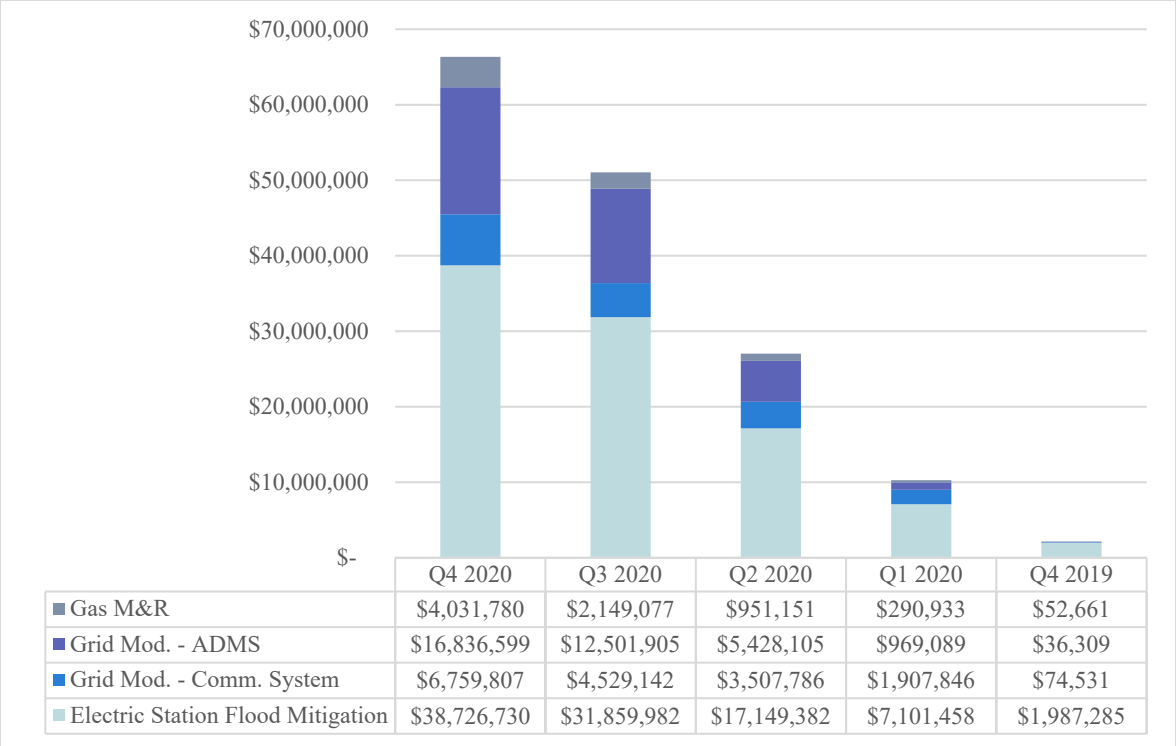
As of December 31, 2020, the ES 2 CWIP balance was $66.4 million, compared to $51.0 million as of September 30, 2020. The largest components of December 31, 2020 CWIP were the work associated with the elimination and conversion of the 4kV circuits at Ridgefield substation ($13.8 million in total), work at Leonia substation ($6.1 million), and work associated with the Advanced Distribution and Management System ($16.8 million). The Electric Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in the **Figure 1 – ES 2 CWIP as of December 31, 2020** below.

Figure 1 – ES 2 CWIP as of December 31, 2020



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2020** below depicts the composition of end-of-quarter CWIP balances by subprogram for each quarter of the year 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2020



	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas M&R	$4,031,780	$2,149,077	$951,151	$290,933	$52,661
Grid Mod. - ADMS	$16,836,599	$12,501,905	$5,428,105	$969,089	$36,309
Grid Mod. - Comm. System	$6,759,807	$4,529,142	$3,507,786	$1,907,846	$74,531
Electric Station Flood Mitigation	$38,726,730	$31,859,982	$17,149,382	$7,101,458	$1,987,285

Transfers from CWIP to plant in-service have totaled $5.2 million as of December 31, 2020, all of which was comprised of Grid Modernization projects. It should be noted that work related to certain assets, such as blanket projects and the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP, and thus, are not recorded as transfers from CWIP. During the fourth quarter of 2020, the company made an adjustment to CWIP to reflect a reversal of about $9.2 million from CWIP to direct in-service. This adjustment was to the Market Street 4kV substation elimination ($7.0 million) and Ridgefield 4kV substation elimination ($2.2 million) to recognize that certain work orders meet the definition of blanket projects and should not have been recorded as CWIP. This adjustment also affected previously recorded amounts for AFUDC (see **Section II.C.3.**).

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during each quarter of 2020, total year 2020, the fourth quarter of 2019, and total ES 2 AFUDC accrued to date, is shown below in **Table 6 – ES 2 AFUDC as of December 31, 2020**.

Table 6 – ES 2 AFUDC as of December 31, 2020

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total AFUDC
Electric Station Flood Mitigation	**$305,014**	**$377,009**	**$191,807**	**$62,618**	**$936,448**	**$9,887**	**$946,335**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total AFUDC
Grid Modernization – Communications	**$66,204**	**$43,496**	**$60,073**	**$14,572**	**$184,345**	**$225**	**$184,570**
Grid Modernization - ADMS	**$213,873**	**$103,228**	**$28,474**	**$7,092**	**$352,667**	**$96**	**$352,763**
Electric Stipulated Base	**$32,603**	**$11,413**	**$0**	**$0**	**$44,016**	**$0**	**$44,016**
Gas M&R Station Upgrades	**$39,594**	**$19,385**	**$8,465**	**$2,590**	**$70,034**	**$254**	**$70,288**
Total	**$657,288**	**$554,531**	**$288,819**	**$86,872**	**$1,587,510**	**$10,462**	**$1,597,973**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies the current year based on updated capital structure and component cost data. For the year 2020, the new AFUDC rate was calculated to be 6.95%, using the capital structure and component costs as of January 31, 2020. In calculating the 2020 AFUDC rate, the Company used (i) a 4.02% embedded cost of long-term debt, (ii) a short-term debt rate of 1.86%, and (iii) a cost of equity of 9.60%.

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the fourth quarter of 2020, based on data as of November 30, 2020, the recalculated weighted average AFUDC accrual rate (6.96%) did not meet this criterion to warrant changing from the annual rate (6.95%) in effect. Therefore, AFUDC was accrued during the fourth quarter of 2020 at the calculated rate of 6.95%.

AFUDC accrued for ES 2 projects during the fourth quarter of 2020, taking into consideration the reclassification referred to above, increased significantly over AFUDC accrued during the third quarter of 2020 as the result of the increases in total average CWIP balances across all subprograms. The reclassification adjustment related to certain work orders for the Market Street and Ridgefield 4kV substations, referred to in **Section II.C.2.**, resulted in a reduction in fourth quarter AFUDC of $186,260.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to fourth quarter 2020 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU

order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Overhead Allocations as of December 31, 2020** are the allocated overhead costs charged to ES 2 projects for all four quarters of 2020, total 2020, the fourth quarter of 2019, and total allocated overheads to date.

Table 7 – ES 2 Overhead Allocations as of December 31, 2020

Subprogram	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Total 2020	Q4 2019	Total Overhead Allocations
Electric Station Flood Mitigation	$4,924,531	$3,890,087	$3,560,216	$1,648,117	$14,022,951	$286,953	$14,309,904
Contingency Reconfiguration	$6,010,891	$3,350,239	$3,055,700	$4,692,085	$17,108,915	$3,415,460	$20,524,375
Grid Modernization – Communications	$2,170,097	$561,011	$548,017	$345,720	$3,624,845	$12,074	$3,636,919
Grid Modernization – ADMS	$111,743	$105,563	$91,786	$116,442	$425,534	$10,603	$436,137
Electric Stipulated Base	$104,386	$155,112	$0	$0	$259,498	$0	$259,498
Gas M&R Station Upgrades	$91,988	$78,452	$68,257	$52,836	$291,533	$15,287	$306,820
*Total**	$13,413,636	$8,140,465	$7,323,975	$6,855,199	$35,733,275	$3,740,376	$39,473,651
**-Note: total figures may not fully align due to rounding.*							

The overwhelming majority of overhead costs allocated to ES 2 projects during the fourth quarter of 2020 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the fourth quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The increase in overheads for the fourth quarter 2020 over the third quarter largely reflects higher ES 2 project activity, and a return to a more normal overhead surcharge pattern from the Isaias storm restoration efforts in August, during which significant bargaining unit labor costs were charged to non-ES 2 projects in connection with service restoration activity.

The IM believes these allocations represent no change in the Company's normal methodology of allocating overhead costs.

D. System Performance

1. Current Reporting Quarter Major Events

During the fourth quarter of 2020, there was one Major Event reported in PSE&G's service territory concerning a State of Emergency declared due to a snowstorm. The State of Emergency was declared by Governor Murphy on December 16, 2020 and was lifted on December 18, 2020. During this Major Event

period, 5,108 PSE&G customers experienced extended service interruptions with all returned to service within 29 hours.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 8 – Q4 2020 Major Event Performance** below.

Table 8 – Q4 2020 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
LAU 8014	0.25642	0.00000
LAU 8035	0.29567	0.00400
LAW 8025	0.16759	0.00269
LUM 8014	0.29932	0.00310
MAY 8013		0.00000
MAY 8014	0.03470	0.00000
NEW 8033	0.00571	0.00000
NOT 8013		0.00000
TNY 4001	0.02964	0.00081
**-SAIDI calculations are in minutes.*		

In the circuit data above, the "0.00000" values in the Report Quarter SAIDI data indicates an outage occurred during this Major Event, but the value is beyond five decimal points captured by PSE&G. As indicated above, there were relatively few circuits impacted by this Major Event with the majority of the affected circuits having experienced outages less the 5-year Major Event average (with the only exceptions being two circuits that had extremely minor outages during this Major Event and no other Major Event outage within the 5-year window that forms the reported Major Event average SAIDI).

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of 2020 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of December 31, 2020**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of December 31, 2020

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020	*Schedule Under Development*																		
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
*-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.

A summary of the subprogram status as of the end of 2020 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2020**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2020

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	14*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	15	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 14 switchgears at 11 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2021** summarizes the planned activities for each project during the first quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2021

Station	Upcoming Activities for Q1 2021	Carryover Activities from Q4 2020
1. Academy Street	• Continued engineering and construction	• None
2. Clay Street	• Vendor drawings received (final switchgear arrangement) • Planning Board hearing for site plan	• None
3. Constable Hook	• Being removed from the ES 2 Program and replaced with additional Life Cycle projects	• Remains in planning/origination stages
4. Hasbrouck Heights	• Contingency plan – electrical layout complete • Submittal of major state licenses and permits • Control drawings issued for construction (IFC) • Civil construction purchase order issued	• None

Station	Upcoming Activities for Q1 2021	Carryover Activities from Q4 2020
5. Kingsland	• Continued design and engineering	• None
6. Lakeside Avenue	• Major equipment (switchgear) purchase order issued • 50% estimate completion	• None
7. Leonia	• Phase 1 civil construction completed • 70% estimate completion • Phase 2-3 civil and electrical purchase orders issued	• None
8. Market Street	• Major regional and county licenses and permits issued	• None
9. Meadow Road	• Continued engineering and design	• None
10. Orange Valley	• License and permitting package issued • 50% estimate completion	• None
11. Ridgefield 13kV	• Phase 1 control drawings IFC • Phase 2 civil and electrical drawings IFC • Phase 1 electrical purchase order issued	• None
12. Ridgefield 4kV	• Civil and electrical demolition design packages IFC	• None
13. State Street	• Electrical construction purchase order issued	• Civil construction purchase order issued
14. Toney's Brook	• Continued engineering and design	• 70% estimate completion
15. Waverly	• Phase 1 civil construction completed • Planning Board hearing for site plan	• Major licenses and permits issued (Soil Conservation District, others were issued in Q4 2020)
16. Woodlynne	• Release control drawings IFC	• Civil and electrical construction purchase orders issued

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of 2020.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,217	$4,374,948	42%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$36,589,553	$995,748	2%
3. Constable Hook	Office	$3,900,000	$1,400,000	$5,300,000	$3,900,000	$115,640	2%
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$17,870,384	$1,279,782	7%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$313,779	4%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,364,023	$602,937	1%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$30,396,846	$6,078,171	19%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$25,674,480	$16,330,794	61%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,310,208	$598,209	7%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,854,669	$439,924	2%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$23,341,969	$6,438,674	25%
12. Ridgefield 4kV	Conceptual	$17,600,000	$2,600,000	$20,200,000	$17,009,752	$11,382,948	56%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$739,738	3%
14. Toney's Brook	Study	$14,300,000	$5,400,000	$19,700,000	$16,205,042	$585,036	3%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$32,525,793	$2,564,563	6%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$1,104,280	6%
Subprogram Total		**$320,000,000**	**$65,500,000**	**$386,500,000**	**$339,403,267**	**$53,945,171**	**14%**

Findings & Observations

- The projects that comprise the Electric Station Flood Mitigation subprogram continue at various phases of execution, with six projects now in construction as of the end of 2020, and the remaining projects continuing to advance in design and pre-construction activities with the exception of Constable Hook which at the end of the fourth quarter largely remained in the planning/origination stage but has since been removed from the ES 2 Program.
- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. The status of the later projects in this subprogram, and in particular Orange Valley, will have to closely be followed to ensure the projects are completed within the ES 2 Program window. As of the end of 2020, the initial project schedule for the Orange Valley project shows an in-service date of January 2024, however PSE&G has informed the IM that the project team will be examining the potential to shorten durations and/or work activities concurrently to pull the in-service date back into 2023.

1. Academy Street

During the fourth quarter of 2020, $2,411,951 was spent on the Academy Street project compared to a forecast of approximately $2.6 million, which brought the total spend to approximately $4.4 million. The variance in fourth quarter spend was largely driven by weather delays and an inability to recover time on

weekends that pushed inside plant civil work into early 2021. As noted in the IM 2020 Third Quarter Report, Academy Street had an earlier than anticipated permit approval and land clearing that supported construction starting earlier than forecasted. The earlier start to construction along with adequate float in the schedule resulted in change to the forecasted in-service date, despite some civil construction work slipping into 2021. Notable activities completed during the fourth quarter of 2020 included:

- Major equipment (switchgear) delivered to site;
- Start of electrical construction; and,
- Civil demolition drawings IFC.

Construction at Academy Street, which started in July 2020 for non-permit work, has advanced to 65% complete inside plant as of the end of 2020, up from 25% at the end of the third quarter of 2020.

In December 2020, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Academy street project estimate to $10.5 million from the previously approved $11.8 million, including a reduction to both the base estimate (-$0.1 million) and R&C (-$1.2 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Electrical construction award lower than estimated (-$0.1 million);
- Inside plant civil time and material cost reduction (-$0.1 million); and slightly offset by,
- Increase in laydown area lease ($0.1 million).

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$150,398	$99,893	$399,935	$1,312,771	$2,411,951

Actuals to Date	Estimate	% of Actuals to Estimate
$4,374,948	$10,500,000	42%

2. Clay Street

During the fourth quarter of 2020, $142,242 was spent on the Clay Street project compared to a forecast of approximately $145,000, which brought the total spend to approximately $1 million. Notable activities completed during the fourth quarter of 2020 included:

- Vendor drawings received for final switchgear arrangement; and,
- Detailed engineering commenced.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$116,409	$219,707	$283,219	$234,171	$142,242

Actuals to Date	Estimate	% of Actuals to Estimate
$995,748	$42,000,000	2%

3. Constable Hook

Through the end of 2020, the Constable Hook project remained largely in the initial planning and origination stages, with the property acquisition for associated 69kV projects planned at the same area still being reviewed (see discussion in the IM 2020 Third Quarter Report and in **Section II.A.1** in this report).

The actual spend by quarter for Constable Hook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$17,889	$51,758	$32,313	$8,419	$5,261

Actuals to Date	Estimate	% of Actuals to Estimate
$115,640	$5,300,000	2%

As this project is being removed from the ES 2 Program and replaced with additional life cycle stations under the Electric Stipulated Base, this will be the last IM report that includes Constable Hook.

4. Hasbrouck Heights

During the fourth quarter of 2020, $422,316 was spent on the Hasbrouck Heights project compared to a forecast of approximately $439,000, which brought the total spend to approximately $1.3 million. Notable activities completed during the fourth quarter of 2020 included:

- Civil and electrical drawings IFC; and,
- Major state license and permit package submitted.

As reported in the IM 2020 Third Quarter Report, a Covid-19 related delay on the associated Hasbrouck Heights 69kV project resulted in a delay to the Hasbrouck Heights ES 2 project. This delay has been extended as of the fourth quarter of 2020, with the planned start of construction shifting to January 2022 (was previously June-August 2021) and the forecasted in-service date to April 2023 (was previously November-December 2022). The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$149,848	$193,879	$188,045	$325,694	$422,316

Actuals to Date	Estimate	% of Actuals to Estimate
$1,279,782	$18,000,000	7%

5. Kingsland

During the fourth quarter of 2020, $30,636 was spent on the Kingsland project compared to a forecast of $42,000, which brought the total spend to approximately $314,000. There were minimal activities performed on this project during the fourth quarter of 2020.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$104,112	$108,286	$43,268	$27,477	$30,636

Actuals to Date	Estimate	% of Actuals to Estimate
$313,779	$8,300,000	4%

6. Lakeside Avenue

During the fourth quarter of 2020, $73,350 was spent on the Lakeside Avenue project compared to a forecast of approximately $82,000. Notable activities completed during the fourth quarter of 2020 included:

- Key drawing review completed;
- Kickoff meeting held;
- Scope document signed off;
- A&E purchase order issued to Black & Veatch; and,
- Commencement of license and permitting design.

As noted in the IM 2020 Third Quarter Report, the Lakeside Avenue forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the initial property relocation identified for the 69kV and ES 2 projects at 338 Washington Street having contamination risks that resulted in a new potential property location at 101 N. Park Street, for which the purchase process is underway. The contamination risks at the 338 Washington Street site related to per- and polyfluoroalkyl substances (PFAS) that are subject to developing federal and state regulations and under increased scrutiny by regulators, increasing the risk exposure at this site. As of the end of 2020, the forecasted in-service date has improved slightly from December 20, 2023 to December 13, 2023 as PSE&G continues to look for opportunities to advance the schedule.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$148,943	$172,224	$121,009	$87,411	$73,350

Actuals to Date	Estimate	% of Actuals to Estimate
$602,937	$47,900,000	1%

7. Leonia

During the fourth quarter of 2020, approximately $4.3 million was spent on the Leonia project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $6.1 million. Notable activities completed during the fourth quarter of 2020 included:

- Contingency switchgear delivered to site;
- Phase 3 civil and electrical drawings and phase 2 control drawings IFC;
- Leonia town council approved the developer agreement (granting permission to proceed with electrical construction of the temporary switchgear).

Construction at Leonia, which started in August 2020, has advanced to 35% complete inside plant as of the end of 2020, up from 15% complete as of the end of the third quarter of 2020. The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$44,792	$244,323	$424,783	$1,071,468	$4,292,805

Actuals to Date	Estimate	% of Actuals to Estimate
$6,078,171	$32,200,000	19%

8. Market Street

During the fourth quarter of 2020, $5,488,046 was spent on the Market Street project compared to a forecast of approximately $4 million, which brought the total spend to approximately $16.3 million. The forecast to actual variance in the fourth quarter was predominantly the result of an accounting transfer of $1.4 million from September to October. Notable activities completed during the fourth quarter of 2020 included the issuance of the civil construction (demolition) bid and award of the associated purchase order for the work. Construction at Market Street, which started in August 2020, has advanced to 60% complete outside plant as of the end of 2020, up from 45% complete as of the end of the third quarter of 2020. Inside plant construction is anticipated to begin in May 2021.

In December 2020, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Market Street project estimate to $26.9 million from the previously approved $30.0 million, including a reduction to both the base estimate (-$1.5 million) and R&C (-$1.6 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Reduced milling, paving, and dewatering (-$0.5 million);
- Civil demolition bids lower than estimated (-$1.1 million); and slightly offset by,
- Higher revised environmental abatement estimate ($0.1 million).

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$251,193	$1,938,713	$5,144,270	$3,508,572	$5,488,046

Actuals to Date	Estimate	% of Actuals to Estimate
$16,330,794	$26,900,000	61%

9. Meadow Road

During the fourth quarter of 2020, $114,608 was spent on the Meadow Road project compared to a forecast of approximately $108,000, which brought the total spend to approximately $598,000. There were minimal activities on the Meadow Road project during the fourth quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$63,128	$142,946	$104,563	$172,964	$114,608

Actuals to Date	Estimate	% of Actuals to Estimate
$598,209	$9,000,000	7%

10. Orange Valley

During the fourth quarter of 2020, $81,191 was spent on the Orange Valley project compared to a forecast of approximately $194,000, which bought the total spend to approximately $440,000. The variance in fourth quarter forecasted to actual spend was driven by lower labor efforts required versus what was forecasted. There were minimal activities on the Orange Valley project during the fourth quarter of 2020, but a couple notable milestones occurred during the quarter, including the sign off on the approved scope document for the project and the transition from Office level to Study level estimate. The first of six parcel purchases associated with this project closed in December 2020, with four more property closures expected in 2021 and the final parcel expected to close in April 2022.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate reduced the total Orange Valley project estimate to $20.2 million from the previously approved $26.6 million, including a reduction to both the base estimate (-$3.7 million) and R&C (-$2.7 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by the previously discussed change in mitigation method from raise and rebuild to relocate (see IM 2020 Third Quarter Report).

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$77,029	$96,582	$120,690	$64,432	$81,191

Actuals to Date	Estimate	% of Actuals to Estimate
$439,924	$20,200,000	2%

11. Ridgefield 13kV

During the fourth quarter of 2020, $2,440,799 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.0 million, which brought the total spend to approximately $6.4 million. Notable activities completed during the fourth quarter of 2020 included:

- Phase 1 civil and electrical drawings IFC;
- Phase 1 controls drawings IFC; and,
- Phase 1 civil construction bid issued.

Construction at Ridgefield 13kV, which started in June 2020, has advanced to 33% complete inside plant as of the end of 2020, up from 23% at the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$205,982	$317,289	$500,475	$2,974,130	$2,440,799

Actuals to Date	Estimate	% of Actuals to Estimate
$6,438,674	$25,500,000	25%

12. Ridgefield 4kV

During the fourth quarter of 2020, $4,637,383 was spent on the Ridgefield 4kV project compared to a forecast of approximately $5.5 million. This brought the total spend to approximately $11.4 million. The variance in actual versus forecasted spend for the fourth quarter was predominantly the result of the contractor losing a week due to Covid-19 quarantine and cable pulling postponed due to Division resources working on another emergent project.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 72% complete, up from 47% at the end of the third quarter of 2020. The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$143,414	$693,128	$2,134,627	$3,774,395	$4,637,383

Actuals to Date	Estimate	% of Actuals to Estimate
$11,382,948	$20,200,000	56%

13. State Street

During the fourth quarter of 2020, $143,244 was spent on the State Street project compared to a forecast of approximately $154,000, which brought the total spend to approximately $740,000. Notable activities completed during the fourth quarter of 2020 included permit approval from the State Department of Community Affairs.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$77,950	$128,288	$172,777	$217,839	$143,244

Actuals to Date	Estimate	% of Actuals to Estimate
$739,738	$45,100,000	2%

14. Toney's Brook

During the fourth quarter of 2020, $74,783 was spent on the Toney's Brook project compared to a forecast of approximately $90,000, which brought the total spend to approximately $585,000. Notable activities completed during the fourth quarter of 2020 included the release of the civil construction work for bid early the quarter and the award of the civil construction work late in the quarter.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$211,940	$115,747	$86,315	$96,251	$74,783

Actuals to Date	Estimate	% of Actuals to Estimate
$585,036	$19,700,000	3%

15. Waverly

During the fourth quarter of 2020, $1,099,112 was spent on the Waverly project compared to a forecast of approximately $1.09 million, which brought the total spend to approximately $2.6 million. Notable activities completed during the fourth quarter of 2020 included:

- Commencement of inside plant civil construction;
- Phase 2 civil and electrical drawings IFC; and
- Major county and federal license and permit packages issued.

Construction at Waverly, which started in October 2020, has advanced to 4% complete as of the end of 2020. The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$103,748	$355,706	$355,335	$650,662	$1,099,112

Actuals to Date	Estimate	% of Actuals to Estimate
$2,564,563	$35,400,000	7%

16. Woodlynne

During the fourth quarter of 2020, $438,374 was spent on the Woodlynne project compared to a forecast of approximately $468,000, which brought the total spend to approximately $1.1 million. Notable activities completed during the fourth quarter of 2020 included the release of civil and electrical drawings IFC.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$110,982	$240,418	$213,482	$101,024	$438,374

Actuals to Date	Estimate	% of Actuals to Estimate
$1,104,208	$19,400,000	6%

B. Contingency Reconfiguration

During the fourth quarter of 2020, work continued to advance in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 207 installed during the quarter and 333 commissioned. **Table 13 – ES 2 Recloser Status as of December 31, 2020** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the 2020 year-end targets and current status of engineering, installation, and commissioning.

Table 13 – ES 2 Recloser Status as of December 31, 2020

Type	Subprogram Forecast	2020 Year End Total Target	Engineering Packages Complete (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
			Q4 Qty.	*Total*	*Q4 Qty.*	*Total*	*Q4 Qty.*	*Total*
13kV	916	800	61	699	115	661	231	644
4kV	567	179	-46*	254	92	157	102	157
Total	1,483	979	15	953	207	818	333	801

*-During the fourth quarter of 2020, PSE&G's Asset Management team evaluated the reclosers planned for the subprogram and removed 102 4kV reclosers. Of these 102 reclosers, 63 were engineered prior to the decision to remove them from the subprogram, which resulted in an overall fourth quarter reduction of the number of engineering packages completed.

As shown in **Table 13**, PSE&G ended 2020 slightly below its targets for the year largely the result of weather-related impacts experienced over the course of the year that temporarily delayed installation and commissioning activities. There is no overall subprogram impact from not hitting these targets as PSE&G maintains flexibility within the subprogram, including keeping engineering comfortably ahead of construction, to allow flexibility in selecting which projects to initiate construction on based on resource or inventory availability. Additionally, as noted within **Table 13**, PSE&G revised the quantity of reclosers for the subprogram as part of a routine review of the planned investments to ensure they are still warranted. The types of criteria involved in removing a recloser from the subprogram include: the circuit may be an underground circuit or a short (one-to-two block circuit) where it is not practical to install a recloser device; the circuit may now be planned for elimination or upgrade in the next five years; or other subsequent investments established three section loops on the circuit. All of these factors contributed to

the reduction in both 4kV and 13kV reclosers. There is no expected change to the subprogram forecast at this time, as PSE&G subsequently made the decision to identify cost-effective opportunities to include additional circuits in the subprogram to improve reliability to a greater number of customers utilizing the same cost-benefit process performed for the initial selection of reclosers in the ES 2 Program filing.

The Fuse Saver pilot program commenced in November 2020 and was completed in January 2021. In total, this Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). A comparison of the Fuse Saver costs estimated at the time of the ES 2 filing compared to the actual costs experienced in the pilot program is provided below in **Table 14 – Fuse Saver Cost Per Unit**.

Table 14 – Fuse Saver Pilot Cost Per Unit

Device Type	ES 2 Filing Estimate	Pilot Program Actual Cost	Variance
Single-Phase	$11,721	$35,316	+$23,595
Two-Phase	$18,262	$48,031	+$29,768

While the cost per unit estimated at the ES 2 filing was based on a few prior installations, certain elements experienced in the pilot program drove the actual costs well above the initial estimate. The key drivers to the higher costs in the pilot program included:

- "Other" costs not included in the filing estimate, such as management costs, traffic control, tree trimming, and storage;
- Higher material costs from what was estimated, which was largely driven by 40% of the locations requiring a pole installation (whereas the filing estimate assumed no pole replacements); and,
- Actual average labor hours per unit approximately four times higher than the filing estimate, which was driven by the learning curve with the new technology, initial issues with the installations, shop testing, and increased labor rates since the time of the filing.

Fuse Saver installations are anticipated to resume in September 2021 pending approval by PSE&G's Asset Management group to proceed with the full scope.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2020**. This table also shows the forecasted dates as of the end of the third quarter of 2020 to show movement to the forecast as of the end of the fourth quarter of 2020.

Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2020

Scope & Division		Q3 2020 Forecasted Completion Date	Q4 2020 Forecasted Completion Date
Reclosers	Central	11/30/2021	9/30/2021
	Metro	11/30/2021	12/31/2021
	Palisades	12/31/2021	12/31/2021
	Southern	12/31/2021	12/31/2021

Scope & Division		Q3 2020 Forecasted Completion Date	Q4 2020 Forecasted Completion Date
Fuse Savers	Central	7/31/2023	6/30/2023
	Metro	7/31/2023	6/30/2023
	Palisades	7/31/2023	5/31/2023
	Southern	7/31/2023	6/30/2023

As shown in **Table 15**, the forecasted completion for each Division's Fuse Saver program advanced one to two months, which was driven by pulling the planned installations forward in the schedule. The two-month advancement of the Central Division recloser scope was driven by accelerating the 4kV installations during a lull in the 13kV recloser inventory. The one-month slip to the Metro Division recloser was driven by the identification of additional units, which have yet to be finalized and approved by PSE&G, but are assumed within the schedule forecast.

The Contingency Reconfiguration subprogram costs through the end of 2020 are presented in **Table 16 – ES 2 Contingency Reconfiguration Costs as of December 31, 2020**.

Table 16 – Contingency Reconfiguration Costs as of December 31, 2020

Scope & Division		Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Reclosers	Central	$2,737,167	$3,918,150	$2,238,132	$2,801,328	$3,093,210	$14,787,987	$22,767,184	65%
	Metro	$2,231,431	$3,576,616	$1,946,751	$1,950,122	$3,253,121	$12,958,041	$23,255,612	56%
	Palisades	$2,515,569	$3,353,246	$2,263,303	$2,602,224	$3,900,664	$14,635,005	$25,083,532	58%
	Southern	$2,081,220	$4,003,537	$2,098,258	$2,764,372	$3,539,516	$14,486,904	$29,406,939	49%
Fuse Savers	Central	$9,970	$29,667	$48,444	$73,176	$638,650	$799,907	$15,944,726	5%
	Metro	$7,557	$15,498	$28,339	$41,921	$476,157	$569,472	$14,156,700	4%
	Palisades	$7,468	$15,259	$16,336	$20,878	$469,981	$529,922	$11,190,352	5%
	Southern	$9,792	$21,458	22,973	$35,596	$778,987	$868,805	$21,001,227	4%
Total		**$9,600,174**	**$14,933,431**	**$8,662,536**	**$10,289,616**	**$16,150,287**	**$59,636,044**	**$162,806,273**	**37%**

Findings & Observations:

- Recloser installations did not meet PSE&G's 2020 target, largely due to weather-related impacts experienced earlier in the year, but PSE&G has sufficient flexibility in its plan that there is no resulting impact to the subprogram from not achieving this target.
- The Fuse Saver pilot program commenced in November 2020 and was completed in January 2021. While Asset Management has not reached a decision on proceeding with the full scope, PSE&G has already identified elements from the pilot program such as improved installation instruction and cost elements to be aware of that will better prepare PSE&G for executing the full scope should it decide to proceed.
- With over half of the forecasted recloser units installed as of the end of 2020 (54%), PSE&G has spent approximately 56% of both its estimated and currently forecasted recloser costs, suggesting actual costs coming in close to the estimate, but will warrant continued monitoring to ensure the subprogram objectives are completed within the estimated costs.
- The current forecast for the subprogram increased approximately $31 million during the fourth quarter of 2020, driven by an increased in the number of 13kV recloser units (approximately

$12.7 million) and an increase in the forecasted cost per unit for Fuse Savers based on the actual cost trend during the pilot program (approximately $34.4 million).

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, in June 2020, the permanent PSE&G Wireless Network infrastructure solution for connecting to the First Net LTE Network was officially placed in-service and is being utilized to manage all traffic from the field routers. Since being placed in-service, PSE&G performed a service territory coverage assessment, which found less than 1/10 of 1% of the service territory had service below the coverage threshold, and initiated actions to boost the signal at these locations at no cost impact to the subprogram.

As also reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the fourth quarter of 2020, 147 retrofit installations took place against a forecast of 69 installations. Actual installations were well above the fourth quarter forecast due to the planned ramp-up for 2021 immediately seeing results, leading to more resource availability than initially planned for the quarter, in addition to a conservative unit forecast for the quarter. The total forecast for the subprogram contemplates retrofitting 2,601 reclosers, of which 189 have been completed as of the end of 2020.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division**.

Table 17 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the fourth quarter of 2020, three of the fiber installation projects (Cranford, Hackensack Sub HQ, and, Southern HQ) and five of the fiber cutover projects (Delair, East Riverton, Mount Holly, Riverside, and Tonnelle) were placed in-service. Eight other projects were in construction as of the end of 2020. Three of the projects that commenced construction in 2020 (Fort Lee, Hadley, and Bloomfield) have had their completion slip to later in 2021 due to Transmission Fiber Infrastructure standards that require fiber communication installations have two active fiber links at all times before putting racks in-service. These stations were designed with a minimum of two links, so there is no expected cost impact from this delay and may actually result in minor cost savings due to not having to return to these sites a second time to place the projects fully in-service.

The Grid Modernization – Communication System subprogram costs through the end of 2020 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2020**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2020

Scope & Division		2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Retrofit Reclosers	Central	$0	$50,613	$150,958	$201,053	$481,655	$884,278	$7,782,220	11%
	Metro	$0	$44,164	$139,069	$214,848	$420,359	$818,620	$6,726,635	12%
	Palisades	$0	$44,164	$138,485	$216,524	$426,001	$825,174	$6,972,356	12%
	Southern	$0	$46,901	$145,479	$198,307	$538,372	$929,058	$8,429,951	11%
Fiber	Central	$1,691	$133,115	$272,307	$660,034	$1,353,395	$2,420,542	$7,479,720	32%
	Metro	$1,457	$109,382	$299,876	$419,162	$1,038,278	$1,868,154	$5,857,646	32%
	Palisades	$1,582	$194,451	$520,068	$403,443	$928,800	$2,048,344	$4,166,762	49%
	Southern	$4,731	$65,721	$139,575	$120,011	$585,176	$915,214	$3,258,924	28%
	Cutovers	$0	$0	$0	$40,869	$835,633	$876,502	$1,085,671	81%
Wireless Network		$74,306	$1,525,801	$2,353,604	$1,508,075	$647,961	$6,109,747	$7,547,000	81%
Bulk Purchase*		-	-	-	$1,124,072	$400,802	$1,524,874	$0	-
Total		**$83,767**	**$2,214,312**	**$4,159,421**	**$5,106,396**	**$7,656,612**	**$19,220,505**	**$59,306,886**	**30%**

***-*The Bulk Purchase account contains expenditures for the bulk purchase of materials in the subprogram. As these materials are used and installed in the field, the Bulk Purchase account is credited with the actual spend then assigned to the appropriate Division, thus at the end of the Program, the balance of this Bulk Purchase account is expected to be $0.*

Findings & Observations:

- Retrofit recloser installations continued to advance in the fourth quarter of 2020, with installations well above the forecast for the quarter. As previously noted PSE&G made a strategic decision for new reclosers (as part of the Contingency Reconfiguration subprogram) continue to have installation priority. PSE&G's prioritization also has taken advantage of other work performed on the line (replacement of copper telephone wires with fiber) to gain cost efficiencies.
- PSE&G identified 41 potential fiber installation projects for the subprogram, with two stations removed from consideration due to the future elimination of those substations.
- The 11 fiber installation projects that were initiated in 2020 all advanced to at least the construction phase, with three of the projects being placed in-service by the end of the year. Additionally, five of the twelve fiber cutover were placed in-service by the end of the year.

- The IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2020 are centered on planning activities, including as previously reported in the second quarter of 2020, the signing of the Open Systems International Inc. (OSII) contract. The ADMS team continues to use remote meetings with the vendor in response to the ongoing Covid-19 issues and continues to conduct design workshops to further develop the application.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the fourth quarter of 2020 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q4 2020 Activities:
    - Scheduled workshops with OSII for control and estimation design;
    - Scheduled DERMS network optimization design workshop;
    - Developed user stories;
    - Reviewed design documents delivered by OSII;
    - Completed Architecture Design & Epic/Story/Spring Planning (milestone);
    - Inserted review session results in new iterations of OSII design documents;
    - Delivery and installation of software licensing; and,
    - Completed DERMS AMI integration workshop and SCADA linking workshop.
- Forecasted Completion as of the end of 2020: 10/28/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q4 2020 Activities:
    - Conducted internal meetings for work/crew management requirements;
    - Shipped laptops to OSI team;
    - Conducted onboarding meetings with Divisions;
    - Conducted configuration and functional training with core team;
    - Conducted data conversion kickoff meeting with OSII, OMS leads, and reporting team;
    - Completed additional user story review sessions, reporting/dashboard workshops, and interfaces sessions;

  - Project toolsets approved by Cyber, Security, Risk, and Compliance Team;
  - Drafted GIS interface for customers and premises;
  - Completed user story review;
  - Conducted kickoff meeting with Automated Testing team;
  - Completed workshops for four interface designs; and,
  - Completed Sprint One with OSII.
- Forecasted Completion as of the end of 2020: 5/20/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing DSCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q4 2020 Activities:
  - Received delivery of servers;
  - Completed Dell Unity configuration;
  - Completed Windows OS build in production environment; and,
  - Connected workstations to Newark PDS server.
- Forecasted Completion as of the end of 2020: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of 2020 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2020**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2020

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$36,213	$925,689	$4,430,542	$6,970,572	$4,210,822

Actuals to Date	Forecast	% of Actuals to Forecast
$16,483,837	$40,374,139	41%

Findings & Observations:

- Additional workshops were held during the fourth quarter, which despite the challenges posed by Covid-19 restrictions, continued to be conducted without issue.
- The IM has found no indications to date that would jeopardize the subprogram being completed on time. The current forecast, including the $1.2 million in additional hardware purchased during the third quarter of 2020, exceeds the Stipulation amount allocated for this subprogram by approximately $5.4 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] As reported

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under

in the IM 2020 First Quarter Report, the preliminary planning by PSE&G estimated that approximately one-third of the Stipulated Base funds will be used towards the electric stations life cycle investments and the remaining two-thirds towards outside plant higher design and construction standards. PSE&G has confirmed with the IM that it intends to maintain the ratio at approximately one-third of funding to life cycle upgrades and two-thirds to outside plant higher design and construction standards. The outside plant higher design and construction standards work is planned to commence in later in 2021 on the State Street project and ramp-up more fully in 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2020**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$362,372	2%	10/24/2022 (↑)
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$840,200	4%	9/28/2022
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$682,325	3%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$551,165	3%	12/28/2022 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 20**, of the four current life cycle station upgrade projects, two had no change in the forecasted in-service date from the third to fourth quarters of 2020 (Paramus and Plainfield), while Hamilton's forecasted in-service date advanced eight days and Woodbury's forecasted in-service date slipped twelve days in this period. Given the small magnitude of these changes, the IM has not performed additional schedule analyses on these projects, but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

During the fourth quarter of 2020, $185,564 was spent on the Hamilton project against a forecast of approximately $166,000. This brought total spend through the end of 2020 on the project to $362,372. Notable activities conducted during the fourth quarter of 2020 included:

- Project execution plan completed; and,
- License and permitting package issued.

the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$0	$0	$0	$177,808	$184,564

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$362,372	$18,200,000	$14,513,934	2%

2. Paramus

During the fourth quarter of 2020, $431,270 was spent on the Paramus project against a forecast of approximately $481,000. This brought total spend through the end of 2020 on the project to $840,200. Notable activities conducted during the fourth quarter of 2020 included:

- License and permitting package issued and submitted;
- Detailed engineering commenced; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$0	$0	$0	$408,931	$431,270

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$840,200	$20,200,000	$16,801,337	4%

3. Plainfield

During the fourth quarter of 2020, $179,136 was spent on the Plainfield project against a forecast of approximately $282,000. This brought total spend through the end of 2020 on the project to $682,325. Notable activities conducted during the fourth quarter of 2020 included:

- License and permitting package issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$0	$0	$0	$503,189	$179,136

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$682,325	$22,600,000	$18,801,708	3%

4. Woodbury

During the fourth quarter of 2020, $167,341 was spent on the Woodbury project against a forecast of approximately $156,000. This brought the total spend on the project to $551,165. Notable activities conducted during the fourth quarter of 2020 included:

- Project kickoff meeting held;
- A/E purchase order issued;
- Detailed engineering commenced;
- Approval of the project execution plan.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$0	$0	$0	$383,851	$167,314

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$551,165	$18,700,000	$14,934,202	3%

Findings & Observations:

- The four electric stipulated base substation life cycle projects continued to progress in planning and preparation efforts during the fourth quarter of 2020 while also advancing engineering in support of the planned release of civil and electrical IFC drawings in the first and second quarters of 2021.
- The electric stipulated base substation life cycle projects are progressing in line with their respective cost and schedule estimates.
- While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards. Funding these four projects fully allows them to be completed within the ES 2 Program window, in addition PSE&G excepts excess funds from the Electric Station Flood Mitigation subprogram (currently forecasted approximately $60 million under its Stipulation amount) to be reallocated to the life cycle station upgrades as provided in the Stipulation.

F. Gas M&R Station Upgrades

Through the end of 2020, primary activities in the Gas M&R subprogram continued to focus on pre-construction activities such as preparing licensing and permitting packages and the continued advancement of engineering on each of the Gas M&R stations. **Table 21 – ES 2 Gas M&R Summary Status as of December 31, 2020** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of December 31, 2020

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Office	$10,000,000	$5,400,000	$15,400,000	$872,676	6%	Jan 2023
2. Central*	Study	$23,900,000	$6,100,000	$30,000,000	$677,451	2%	Jan 2023
3. East Rutherford	Study	$13,800,000	$3,200,000	$17,000,000	$530,875	3%	Dec 2022 (↑)
4. Mount Laurel	Study	$9,400,000	$2,400,000	$11,800,000	$368,132	3%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,700,000	$14,200,000	$471,294	3%	Dec 2023 (↓)
6. Westampton	Study	$8,300,000	$2,100,000	$10,400,000	$1,041,065	10%	Dec 2021
Placeholder**	-	$0	$2,200,000	$2,200,000	$0	-	-
Subprogram Total		**$76,900,000**	**$24,100,000**	**$101,000,000**	**$3,961,492**	**4%**	**Dec 2023**

**-Included in the Stipulated Base.*
***-Represents additional funds between the current project estimates and the Stipulation amount for the subprogram.*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

The changes to the East Rutherford (advancing one month) and Paramus (slipping 11 months) project schedules was due to a realignment of the project schedules to avoid the constraint of not being able to have these two stations in construction at the same time (a similar situation exists at the Mt. Laurel and Westampton projects).

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects, preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages. Continued engineering and design efforts were a main focus of 2020 fourth quarter activities.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. Three of the Gas M&R projects had updated estimates approved by the URB during the fourth quarter of 2020, which resulted in two of the projects (Central and East Rutherford) having an increased base estimate, somewhat offset by a reduced R&C, while the other project (Paramus) had a reduction to both the base and R&C estimates, with no change to the overall subprogram estimate.

1. Camden

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Camden project included:

- Coordination meeting held with the Audubon District and Remediation;
- 3D preliminary drawings completed;
- Preliminary permitting meeting held with the City; and,
- Permitting package prepared.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$13,326	$46,691	$83,499	$207,837	$521,323

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$872,676	$15,400,000	$10,000,000	6%

2. Central

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Central project included:

- Completed initial geotechnical review;
- Identified major equipment list and long lead items;
- Completed soft digs to verify tie-in locations and clearances for liquid propane air (LPA) rack foundations; and,
- Permitting package received.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate increased the total Central project estimate to $30.0 million from the previously approved $19.7 million, which also included a slight reduction to R&C (-$0.8 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher construction costs based on the engineer's 50% estimate ($6.9 million);
- Procurement of an additional two buildings and four heaters required for the refined design ($3.0 million); and,
- Additional Project Management, Licensing and Permitting, and Engineering support not included in the Office level estimate ($1.2 million).

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Actuals				
$6,869	$45,048	$109,557	$195,119	$320,858

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$677,451	$30,000,000	$23,900,000	2%

3. East Rutherford

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the East Rutherford project included:

- Reviewed 3D preliminary drawings;
- Identified major equipment and long lead items; and,
- Issued large equipment specs for internal review.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate increased the total East Rutherford project estimate to $17.0 million from the previously approved $15.9 million, including a reduction R&C (-$2.4 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher construction costs based on the engineer's 50% estimate ($2.7 million); and,
- Additional Project Management support not included in the Office level estimate ($0.8 million).

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$9,010	$37,747	$111,526	$159,165	$213,428

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$530,875	$17,000,000	$13,739,809	3%

4. Mount Laurel

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Mount Laurel project included:

- Received draft site plan package; and,
- Received 70% design drawings for review.

Also during the fourth quarter of 2020, the A/E (J.F. Kiely Service Co.) project manager was replaced following discussions PSE&G had with the A/E on project progress.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$5,965	$27,804	$74,737	$132,680	$126,945

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$368,132	$11,800,000	$9,400,000	3%

5. Paramus

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Paramus project included:

- Reviewed 3D preliminary drawings;
- Identified major equipment and long lead items; and,
- Issued large equipment specs for internal review.

In December 2020, the Study level estimate was submitted and approved before the URB. This Study level estimate reduced the total Paramus project estimate to $14.2 million from the previously approved $19.9 million, including a reduction to both the base estimate (-$1.4 million) and R&C (-$4.4 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by the cost of using existing building structures rather than building new.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$8,842	$37,793	$91,247	$169,249	$164,163

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$471,294	$14,200,000	$11,476,028	3%

6. Westampton

While the primary work through the end of 2020 on the Gas M&R subprogram has focused largely on preliminary engineering and other planning activities, during the fourth quarter of 2020 notable activities completed on the Westampton project included:

- Completed soft digs to confirm tie-ins;
- Final site plan reviewed;
- Ordered data building (houses equipment for SCADA and other communication/data systems) and regulator buildings;
- Identified major equipment and long lead items; and,
- Submitted municipal/county permit package.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below.

Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
		Actuals		
$8,395	$40,389	$180,947	$314,493	$496,390

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,041,065	$10,400,000	$8,300,000	10%

IV. Additional Information Following the End of the Fourth Quarter of 2020

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the fourth quarter of 2020, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2020 Fourth Quarter Report.

A. Decisions Recorded After the Fourth Quarter of 2020

Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project

The Clay Street ES 2 project and the Clay Street 69kV transmission project are being executed contemporaneously. PSE&G's capital accounting determination established that the wall to be constructed around the Clay Street Substation to prevent wastewater intrusion is a Transmission and Distribution (T&D) asset. PSE&G has determined the primary purpose of the wastewater wall is health and safety and reliability and is not required for flood mitigation, however, the site is located within a flood zone and thus still requires the flood mitigation scope. Thus, PSE&G made the decision on February 2, 2021 to remove the scope of work of the wastewater wall, raising of grade, and pumping system from this ES 2 project and add it instead to the ongoing 69kV project.

Alternatives considered include:

1. Include the wastewater wall as part of ES 2 Program;
2. Do not construct the wastewater wall;
3. Resolve the issue with the City of Newark and the Passaic Valley Sewerage Commission (PVSC) to prevent overflows from combined sewer/storm water events.

In evaluating the alternatives, PSE&G determined constructing the wastewater wall was the only technical solution identified by Stakeholders to effectively keep the site free from combined sewage and storm water inundation. The frequency of incidents of overflowing storm water across the substation site has increased in the past several years, with each occurrence requiring costly remediation and clean-up and delays access to the site and increased risk to reliability.

PSE&G also determined that attempting to resolve the issue with the City of Newark and PVSC to be ineffective based on numerous meetings over the years with minimal improvement to the overflow and storm conditions.

PSE&G further determined that including the wastewater wall as part of the ES 2 Program was not a preferred alternative since the scope of the work was not required to meet the flood mitigation objectives of the Program. As a result of the decision to remove this scope from the Clay Street ES 2 project, the estimate for the project was reduced by approximately $6.8 million.

Findings and Observations

- The IM finds that PSE&G conducted the appropriate due diligence, evaluation and analysis in determining to remove the wastewater wall scope from the ES 2 Program.

- The need for the wastewater wall was approved during 2019 Project Council meetings and in both the Feasibility Assessment Report and the project scope document for the Clay Street ES 2 project were approved to include the wastewater wall and necessary for health, safety, and reliable operation.
- The IM finds PSE&G's decision to include the wastewater wall under the 69kV project consistent with the capital accounting determination.

B. Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes

Relating to the discussion in **Section II.A.1.** in this IM 2020 Fourth Quarter Report and prior discussions within the IM 2020 Third Quarter Report (Sections II.A.3. and IV.B.), in September 2020, PSE&G formally proposed a change to the mitigation method at Lakeside Avenue, Orange Valley, and Constable Hook from raise and rebuild to relocate, which continued to be discussed between PSE&G, Rate Counsel and BPU Staff through the end of 2020. On January 6, 2021, PSE&G informed the parties that all requested information regarding the changes have been identified and provided to both the BPU Staff and Rate Counsel. PSE&G also stated that it is moving forward with the changes as discussed in part to benefit from the identified efficiencies, which will result in savings and increased reliability for customers. Rate Counsel responded to PSE&G on January 19, 2021, noting specific concerns regarding the proposed changes to the Constable Hook substation and opining that the proposed changes to the Constable Hook project should be excluded from the ES 2 Program.

On February 19, 2021, PSE&G, Rate Counsel, and BPU Staff participated in a conference call to discuss Rate Counsel's objections. During this call, PSE&G explained the proposed change for the Constable Hook substation as consistent with its response to discovery request S-PSEG-ENG-002, including that any costs associated with addressing load growth would be tracked separately under a base capital project and not recovered through the ES 2 accelerated recovery mechanism. However, due to the complexities associated with this project, it became apparent that PSE&G would not be able to complete the Constable Hook project within the ES 2 Program window. Accordingly, PSE&G informed the parties of its intent to remove the Constable Hook substation from the ES 2 Program and instead perform this flood mitigation work as a base capital project. PSE&G also noted its intent to use the funds allocated for Constable Hook to perform additional life cycle station work in accordance with the terms of the Stipulation.

Early in the second quarter of 2021, PSE&G proposed the Front Street substation as a candidate for an additional life cycle station project that can utilize funds intended for the Constable Hook under the ES 2 Program. The IM will continue report on the status of this change as it becomes formalized through PSE&G's processes and as the additional life cycle station work is formally selected.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2020 FOURTH QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

SEPTEMBER 24, 2021

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2020 Fourth Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Page 2** Regarding the Electric Station Flood Mitigation project "Hasbrouck Heights", please provide additional details about the COVID-related delays on the Siemens GIS installation, which caused the forecasted in-service date of the project to be delayed from December 2022 to April 2023.	This delay stemmed from the GIS equipment manufacturer (Siemens) being delayed from travelling to the U.S. to assist with the installation of the GIS equipment on the Hasbrouck Heights 69kV project. This delay rippled to the ES 2 Hasbrouck Heights project, which requires the 69kV project to be installed first. Additionally, the April 2023 in-service date reported at the end of 2020 was identified by PSE&G as the date the Capacitor bank is scheduled to be placed in-service; as of the end of the first quarter of 2021, PSE&G updated the in-service date on the ES 2 Hasbrouck Heights to reflect the major asset/switchgear in-service date of February 2023.	No change
S-INF-2	**Reference Page 5, Market Street Radioactive Soil Testing and Handling** With respect to radioactive soil testing and handling associated with the Electric Station Flood Mitigation project "Market Street": a. Please clarify if the costs associated with the excavation, testing, and monitoring of hazardous waste are included within the costs of the Energy Strong II program. b. If so, please provide an estimate of these costs.	The scope of work on the Market Street project includes excavation of soil in areas designated by the EPA as potentially hazardous due to radioactivity in order to replace existing poles and related infrastructure. In order to safeguard workers and the general public, the work plan as approved by the EPA includes testing and monitoring of hazardous soil excavations. The estimated incremental cost for soil excavation, testing, and monitoring activities is approximately $1.8 million.	**Section II.A.3.**
S-INF-3	**Reference Page 20, Orange Valley** Regarding the Electric Station Flood Mitigation project "Orange Valley", what is attributed to the variance in actual spending ($81,191) and forecasted spending ($194,000) during the quarter?	The variance in fourth quarter forecasted to actual spend was driven by less than estimated A/E efforts as the project finalized the license and permitting matrix and drawings for site plan approval. PSE&G labor efforts for major equipment procurement were also lower than estimated for the quarter.	**Section III.A.10.**
S-INF-4	**Reference Page 23, Table 13 – "ES 2 Recloser Status as of December 31, 2020"** Regarding the statement "During the fourth quarter of 2020, PSE&G's Asset Management team evaluated the reclosers planned for the subprogram and removed 102 4kV recloser."	PSE&G routinely reviews the reclosers and other investments in the ES 2 Program to ensure the initially planned investments are still warranted. For the reclosers, each circuit was assessed to determine the current status reflective of updated system plans and changes, as well as other work done subsequent to the ES 2 filing, such as poorest performing circuit improvements. The types of criteria involved in	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
	a. What is the Company's rationale for removing 102 4kV reclosers from the Contingency Reconfiguration subprogram during the fourth quarter of 2020? b. What is the estimated subprogram budget savings resulting from this decision?	removing a recloser from the subprogram include: the circuit may be an underground circuit or a short (one-to-two block circuit) where it is not practical to install a recloser device; the circuit may now be planned for elimination or upgrade in the next five years; or other subsequent investments established three section loops on the circuit. All of which contributed to a reduction in both 4kV and 13kV reclosers. There is no estimated subprogram budget savings at this time, because subsequent to this review of the initially identified circuits, PSE&G made the decision to conduct a detailed review of 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram in order to improve reliability to a greater number of customers utilizing the same cost-benefit process performed for the initial selection.	
S-INF-5	**Reference Page 25, Contingency Reconfiguration Subprogram** Regarding the statement "The current forecast for the subprogram increased approximately $31 million during the fourth quarter of 2020, driven by an increase in the number of 13kV recloser units (approximately $12.7 million) and an increase in the forecasted cost per unit for Fuse Savers based on the actual cost trend during the pilot program (approximately $34.4 million)." a. Please provide the total number of additional 13kV recloser units included within the subprogram. b. Please provide the Company's rationale for increasing the number of 13kV recloser units within the subprogram. c. Please compare the actual unit cost of Fuse Savers to the originally forecasted cost per unit. d. Does the Company expect to gain any cost savings on Fuse Savers after transitioning from a pilot program to bulk purchasing?	a. The total number of additional 13kV recloser units continues to be under evaluation with 253 13kV opportunities identified by PSE&G as of June 2021 (in addition to 89 additional 4kV opportunities identified). The increase in the fourth quarter forecast reflected additional placeholder units that PSE&G expects to be included in the subprogram based on this evaluation. b. PSE&G decided to identify additional reclosers for the subprogram in order to maximize customer reliability benefits in a cost effective manner. Adding additional reclosers supports faster storm restoration, improved reliability, and reducing the number of customers impacted by a particular outage event. The proposed recloser additions to the subprogram are following the same cost-benefit framework used in the original filing, including having a minimum benefit to cost ratio that is greater than one. c. PSE&G's Fuse Saver unit cost at the time of the ES 2 filing was $11,721 for a single-phase unit and $18,262 for a two-phase unit. The actual average cost per unit experienced in the Fuse Saver pilot program were $35,216 for the single-phase units and $48,031 for the two-phase units. The variance was largely driven by components required that were not part of the initial assumptions (management costs,	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		traffic control, tree trimming, etc.) and higher material and labor costs than what was estimated. d. Yes, PSE&G anticipates that when the Fuse Saver installations fully commence that it will see meaningful improvements in the cost per unit. Specifically, PSE&G expects cost savings due to: 1) higher quantity of units installed, while management costs remain relatively flat; 2) reduction in hours per unit driven by efficiencies gained with the installation of a higher quantity of units; 3) avoidance of extended installation hours seen in the pilot program due to communication issues (modular external antenna assembly being incorporated for trouble locations as needed); and, 4) assumption there will be no additional technical issues that require multiple days/visits to complete an installation.	
S-INF-6	**Reference Page 25, Grid Modernization – Communication System Subprogram** Regarding the statement "During the fourth quarter of 2020, 147 retrofit installation took place against a forecast of 69 installations", what does the Company attribute to the variance in recloser retrofit installations during the fourth quarter of 2020?	The actual installations in the fourth quarter of 2020 were well above the forecast due to the planned ramp-up for 2021 immediately seeing results, leading to more resource availability than planned and coupled with a conservative forecast for the fourth quarter.	**Section III.C.**
S-INF-7	**Reference Page 31, Findings & Observations** Refer the statement "While the current four electric substation life cycle projects comprise approximately 80% of the electric stipulated base funding, PSE&G anticipates that the final ratio will be closer to one-third of funding to the electric substation life cycle projects and two-thirds to the outside plant higher design and construction standards." Has PSE&G incurred any costs for outside plant higher design work to date? If so, please quantify these costs.	No, the outside plant higher design work is anticipated to commence in 2021 (on the State Street project) and ramp-up in 2022.	**Section III.E.**
S-INF-8	**Reference Page 35, Paramus M&R Station** Refer to the statement "the changes to the base estimate were driven by the cost of using existing building structures rather than building new": a. What is the age of the existing building structures that will be used for the Paramus M&R Station project? b. With respect to the Gas M&R Station Upgrade projects, please indicate if PSE&G identified any other existing	Regarding these questions on the Gas M&R subprogram and the Paramus project specifically: a. PSE&G does not have a record of the exact year the Paramus M&R building was originally built as it was built by Transco under an agreement signed on June 6, 1961. PSE&G assumes the station was built within a couple years of that agreement.	No change

ID #	Question/Comment	IM Response	Report Changes
	major equipment that is not near end of life and can be reused within the new M&R stations.	b. PSE&G has identified the following existing equipment to be reused at each site: • Camden: two propane vaporizers. • Central: two Mono Ethylene Glycol units. • East Rutherford: two line heaters. • Mt. Laurel: four line heaters. • Paramus: one scrubber. • Westampton: three line heaters.	
S-INF-9	**Reference Page 36, Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project** Refer to the statement "PSE&G's capital accounting determination established that the wall to be constructed around the Clay Street Substation to prevent wastewater intrusion is a Transmission and Distribution (T&D) asset. PSE&G has determined its primary purpose is health and safety and reliability is not required for flood mitigation. Thus, PSE&G made the decision on February 2, 2021 to remove the scope of work of the wastewater wall, raising of grade, and pumping system from this ES 2 project and add it instead to the ongoing 69kV project." a. Please discuss the cost impact that this adjustments is expected to have on the Clay Street substation project within the Energy Strong II program. b. Please clarify if the shifting of this work scope from the Energy Strong II program to the 69kV project will result in PSE&G reclassifying distribution-related costs as transmission-related costs. c. Please confirm that PSE&G still believes that the raising of the Clay Street substation is required for flood mitigation purposes.	a. The wastewater wall scope change reduces the estimate of the ES 2 Clay Street project by approximately $6.8 million. b. Yes, the costs associated with this scope of work will be transferred to the Clay Street 69kV Project and classified as transmission-related costs. c. Yes, the Clay Street substation is located within a flood zone and the existing regulators/reactors are located on the ground level. Raising and rebuilding the station at least one foot above the flood elevation level will increase the reliability and resiliency of the substation and bring it in compliance with current International Building Code and PSE&G standards.	**Section IV.A.**
S-INF-10	**Reference Page 37, Additional Information on the Constable Hook, Lakeside Avenue, and Orange Valley Mitigation Changes** Refer to the statement "Early in the second quarter of 2021, PSE&G proposed the Front Street substation as a candidate for an additional life cycle station project that can utilize the funds intended for the Constable Hook under the ES 2 Program."	As of the most recent data received by the IM to date, the Front Street life cycle station project has initiated preliminary planning with approximately $190,000 incurred during the second quarter of 2021.	No change

ID #	Question/Comment	IM Response	Report Changes
	Please describe the status and any costs incurred for the Front Street life cycle station project.		
RCR-INF-1	With reference to Table 2- ES-2 Electric Station Flood Mitigation Status as of December 31, 2020 and Table 2- ES-2 Electric Station Flood Mitigation Status as of September 30, 2020, please explain if the proposed change of mitigation strategy estimate of $47.9 million (including risk and contingency) has been updated since December 31, 2020.	As of the most recent data received by the IM to date, there has been no update to the Lakeside Avenue $47.9 million estimate since December 2020. The next estimate (transitioning to the Conceptual level) is expected to be completed in the first quarter of 2022.	No change
RCR-INF-2	With reference to Table 2- ES-2 Electric Station Flood Mitigation Status as of December 31, 2020, please indicate if the Company anticipates that the extended timeline for the Clay Street, Hasbrouck Heights, Orange Valley, Ridgefield 13 kV, and Woodlynne substations will extend beyond current forecasts.	PSE&G updates the Electric Station Flood Mitigation project schedules on a monthly basis based on the actual status and trends observed. The forecasted completion dates commonly change due to a wide variety of factors (weather, productivity, impacts from dependent projects, changing Covid-19 requirements, material/procurement status, permitting status, etc.), with varying impacts to the project schedules as demonstrated by the fourth quarter of 2020 status showing four projects advancing and five projects slipping in their forecasted in-service dates from the prior quarter. In evaluating the actual status and trends, PSE&G regularly looks for opportunities to improve the project schedule, such as by re-sequencing work or identifying activities that can be performed concurrently. Regarding the five projects identified in this comment that saw the forecasted in-service date slip from the third to fourth quarter of 2020, as of the most recent data received by the IM (second quarter 2021) only one project, the Ridgefield 13kV project, has seen the forecasted in-service date slip beyond what the fourth quarter 2020 forecast was, with a second quarter of 2021 forecast of 11/8/2022 vs. the fourth quarter 2020 forecast of 10/13/2022.	No change
RCR-INF-3	With reference to page 4 of the Draft 2020- Fourth Quarter Report, please indicate the number of reclosers, not part of ES II, that were fitted with the ES II wireless communications devices in 2020.	No wireless communication devices (radios) were installed on non-ES 2 reclosers in 2020.	No change
RCR-INF-4	With reference to page 4 of the Draft 2020- Fourth Quarter Report, please indicate the annual number of reclosers, not part of ES II, that are estimated to be fitted with the ES II wireless communications devices through the completion of the Grid Modernization program in December 2023.	During 2021, as of late August 2021, wireless communication devices have been installed on 10 non-ES 2 reclosers with the possibility of three more by the end of the year. For years 2022-2023, there is not an estimate of planned number of radios to be installed in non-ES 2 reclosers. However, PSE&G anticipates that non-ES 2 installations	No change

ID #	Question/Comment	IM Response	Report Changes
		and replacements will continue to be required as part of normal operations and systems build.	
RCR-INF-5	With reference to page 5 of the Draft 2020- Fourth Quarter Report, please provide an update on the status of the Market Street substation and the estimated completion date of September 2021.	During the second quarter of 2021, outside plant 4kV circuits were converted to 13kV. During the summer of 2021, electrical and civil demolition will commence, which will continue after the outside plant 26kV reconfiguration is completed in September 2021 that marks the final asset being placed in-service on this project.	No change
RCR-INF-6	With reference to Table 12- ES-2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, please provide an update on the status of the Lakeside property sale and purchase.	PSE&G closed on the Lakeside property (151-155 N. Park Street) on July 14, 2021.	No change
RCR-INF-7	With reference to Table 12-ES-2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, please provide an update on the status of the Orange Valley property sale and purchase.	The Orange Valley project contemplates the acquisition of six properties. Three of these properties closed in December 2020, March 2021, and June 2021, respectively. The remaining three property acquisitions are expected to close in September 2021, October 2021, and April 2022.	**Section III.A.10.**
RCR-INF-8	With reference to page 16 of the Draft 2020- Fourth Quarter Report, please explain if weekend work scheduling is currently factored into the cost estimates for the Energy Strong II program. If not please explain the impact of weekend and off-hours work on project costs.	Regarding the specific comment on page 16 of the Draft Report ("The variance in fourth quarter spend was largely driven by weather delays and an inability to recover time on weekends that pushed inside plant civil work into early 2021"), Jersey City, where the project is located, has a moratorium on weekend work. Generally speaking, overtime or weekend work performed by PSE&G crews does not have a cost impact, while contractor performed work may or may not depending on the situation. On the PSE&G performed work, the labor rates do not change with overtime/weekend work. Project management and oversight costs are included in overhead costs that are scheduled in advance to install the planned number of units within the planned timeframe. Thus, project management/oversight costs would have no change from overtime/weekend work provided all units planned for the month are completed. For Outside Plant – Underground/Overhead line work done by the Divisions, resources are planned to meet the project schedule. Outage requirements and other system/operational considerations are primary drivers of the time-of-day and/or day-of week planned for the work. In the event that "schedule recovery"	No change

ID #	Question/Comment	IM Response	Report Changes
		efforts are required to make up for weather or other disruption, the resource cost does not change with overtime/weekend work. On the contractor performed work, each project will make decisions on if and how to execute schedule recovery using overtime/weekend work. Generally, the cause of disruption, contract terms, and critical schedule among other things forms the parameters of such decisions. The project risk registers include schedule impacts and make R&C provisions in project budget to cover estimated schedule impact/recovery cost. If the schedule is constrained by system reliability, safety, environmental, or other operational requirements that would be the determinant of the recovery actions, rather than cost impact. If the impact of the delay can be accommodated, that is, the impacted activity will not extend the critical path nor incur additional cost, weekend/overtime work would not be utilized at additional cost. If the schedule impact extends the critical path (project duration), or there is a cost associated with the delay such as impact time payment to contractor, equipment stand by cost, demobilization and re-mobilization cost, demurrage cost, extended storage cost, etc., then the decision on whether to implement weekend/overtime work is based on a minimum cost.	
RCR-INF-9	With reference to page 18 of the Draft 2020- Fourth Quarter Report, please describe the contamination risks associated with the original property.	The environmental conditions found via investigation at the Washington Street property were Per- and polyfluoroalkyl substances (PFAS). PFAS chemicals are EPA contaminants of emerging concerns currently subject to developing federal and state regulations and standards and increasing scrutiny by regulators. The presence of PFAS represented a significant environmental risk leading to PSE&G no longer considering this site for the Lakeside Avenue project.	**Section III.A.6.**
RCR-INF-10	With reference to Table 15 Contingency Reconfiguration Costs as of December 31, 2020 and Table 11 Contingency Reconfiguration Costs as of March 31, 2020, please explain the increase in the subprograms' estimated cost from $119.5 million to $162.8 million.	The fluctuations from quarter to quarter in the Contingency Reconfiguration subprogram forecast have been discussed in prior IM reports, in summary: • In the IM Q2 2020 Report, the forecast as of June 30, 2020 increased approximately $31 million from the prior quarter, which was driven by the full forecasting of the Fuse Saver scope of the subprogram that had previously only been partially forecasted. • In the IM Q3 2020 Report, the forecast as of September 30, 2020 decreased approximately $18 million from the prior	No change

ID #	Question/Comment	IM Response	Report Changes
		quarter, which was driven by the removal of over 200 4kV and 13kV reclosers from the scope of the subprogram. • In this IM Q4 2020 Report, the forecast as of December 31, 2020 increased approximately $31 million from the prior quarter, which was driven by an increase in the planned recloser units (placeholders while PSE&G continued to evaluate the circuits) and an increase to the Fuse Saver scope of the subprogram based on the actual cost trend realized in the pilot program. As demonstrated above, the overall change in the Contingency Reconfiguration subprogram forecast from the first to fourth quarter of 2020 was driven predominantly by changes in the scope of the subprogram (i.e. number of reclosers planned) and an evolving forecast of the Fuse Saver scope (initially only partially forecasted, then full forecasted, and more recently updated based on the experience of the pilot program).	
RCR-INF-11	With reference to Table 17 ES 2 Grid Modernization-Communication System Costs as of December 31, 2020 and Table 13 ES 2 Grid Modernization-Communication System Costs as of March 31, 2020, please explain the decrease in the subprograms' estimated cost from $65 million to $59.3 million.	The reduction in the Grid Modernization – Communication System subprogram forecast of approximately $6 million from March 31, 2020 to December 31, 2020 is nearly entirely attributed to lower costs in the wireless network scope of work. These lower costs are driven by the selection of FirstNet, which provided the wireless network at a cost well under what was initially estimated for this scope of work (see the IM Q1 2020 Report and IM Q3 2020 Report for more discussion on the selection of FirstNet).	No change
RCR-INF-12	With reference to page 36 of the Draft 2020- Fourth Quarter Report, please explain if the allocation of the wastewater wall to the ongoing 69 kV project was the primary factor in seeing the estimated project cost drop from $42 million to the current forecast of $36.6 million. If not, please explain.	Yes, the scope change for the wastewater wall resulted in a decrease to the forecast of approximately $6.8 million (which was slightly offset by marginally higher estimates for other scopes of work on the project). The project also transitioned to the Conceptual level estimate in May 2021, which resulted in a new estimate of $33.8 million for the project, reflecting this scope change and other updated cost estimates for the project.	**Section IV.A.**
Rate Counsel 8/4/2020 Letter to IM	As expected, the quarterly spending trends have been accelerating as more projects enter into construction for the ESII program. Also, we note that the trend in Risk and Contingency are moving downward as projects enter the construction phase.	The spend is expected to continue to accelerate as more activity on the ES 2 Program continues to advance. For the projects carrying an R&C balance, those balances naturally are reduced as the projects advance through engineering and into construction in conjunction with advancing through PSE&G's estimating phases. In effect, either the individual risks are realized,	No change

ID #	Question/Comment	IM Response	Report Changes
		shifting the funds from R&C to the base estimate, or the risks are avoided/mitigated and the overall estimate amount is reduced.	
Rate Counsel 8/4/2020 Letter to IM	At the end of the fourth quarter 2020, the Energy Strong II ("ESII") program remains in the early stages. The Independent Monitor reports that spending for the quarter ending December 31, 2020 has been $52,629,214 or 6.7 percent of the forecasted $778,706,402 program (including the $100 million for Electric Stipulated Base and excluding $89.6 million of risk and contingency). Rate Counsel notes that the parties stipulated to $842 million to complete the ES II Program with $641 million for electric, $50.5 million for gas, and $150.5 million within Stipulated Base for electric and gas spending.	The IM adds a point of clarification to this comment that the forecast of $778,706,402 for the ES 2 Program includes the Stipulated Base for both electric and gas spending (with the Stipulated Base gas spend included within the Gas M&R subprogram figures).	No change
Rate Counsel 8/4/2020 Letter to IM	The current forecast for the Electric Flood mitigation program increased from $332,662,596 in the Second Quarter Report to $339,403,267 in the Fourth Quarter Report, not including risk and contingency estimates. However, Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2020, states that the base spending amount for the subprogram is $320,000,000 in budgeted base project costs and $65,500,000 allocated to risk and contingency.	This is correct, the end of fourth quarter 2020 forecast for the Electric Station Flood Mitigation subprogram is also shown in **Table 12** in addition to the current project estimates (as split between base estimate and R&C) shown in the same table.	No change
Rate Counsel 8/4/2020 Letter to IM	The Independent Monitor notes three formal RODs were issued during the fourth quarter of 2020. These three RODs included Communications Retrofit and non-ES-II Units, Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project, and Market Street Radioactive Soil Testing and Handling- ESII-FM-1.	The RODs issued during the fourth quarter included: Grid Modernization – Communication System Subprogram: Fiber Scope (discussed in the IM 2020 Third Quarter Report), Communication Retrofit of Replacement and non ES-II Units, and Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project. This IM 2020 Fourth Quarter Report also discussed the Market Street Radioactive Soil Testing and Handling-ESII-FM-1 decision, which was made early in the first quarter of 2021.	No change
Rate Counsel 8/4/2020 Letter to IM	The Fourth Quarter Report notes: "As noted in the IM 2020 Third Quarter Report, the Lakeside Avenue forecasted in-service date for this project slipped from May 2023, as of the end of the second quarter of 2020, to December 2023, as of the end of the third quarter. This delay was driven by the original property location for the 69kV and ES 2 projects having contamination risks that resulted in a new potential property location, for which the purchase process is underway. As of the end of 2020, the forecasted in-service date has improved slightly from December	The contamination risks were not associated with the original Lakeside Avenue location. This original location had a small site footprint that, due to the unavailability of adjacent property, would require a customized design and complicated construction sequence including the need to temporarily relocate the 4kV switchgear. PSE&G ultimately identified the new property for the Lakeside Avenue substation at the 101 N. Park Street site, as detailed in its September 24, 2020 Change in Mitigation Method letter. This new	**Section III.A.6.**

ID #	Question/Comment	IM Response	Report Changes
	20, 2023 to December 13, 2023 as PSE&G continues to look for opportunities to advance the schedule." Fourth Quarter Report at page 18. The reference to contamination risks at the original property was not mentioned in PSE&G's original Change of Mitigation Strategy letter dated September 24, 2020. Specifically, the September 24th letter stated "[t]he ES II flood mitigation filing assumed acquisition of adjacent property to install the raised switchgear. However, the property was not available, and a more complicated construction sequence requiring temporary relocation of the 4kV switchgear would be necessary. The initial Lakeside site is very small and would require a customized design to accommodate both the distribution and transmission facilities on the property. It would also require use of contingencies and cutovers that will increase safety, environmental and reliability risks, and pose a challenge to mitigate." PSE&G Change In Mitigation Method Letter, page 2. Rate Counsel has concerns that environmental contamination risk on the original property was not disclosed as the reason for the Company's decision to seek to acquire the 101 N. Park Street location.	site offered lower overall costs vs. the existing location, lower construction risk and outage contingencies, and the benefit of allowing a standard PSE&G design. Prior to selecting the 101 N. Park Street site, PSE&G considered property at 338 Washington Street. This site was determined not viable due to environmental concerns with the site (see also the response to RCR-INF-9 above), which drove the delay in the in-service date initially reported in the IM 2020 Third Quarter Report.	
Rate Counsel 8/4/2020 Letter to IM	Additionally, the Fourth Quarter Report noted that the Contingency Reconfiguration subprogram total forecast increased from $131,898,033 in the Third Quarter Report to $162,806,273. The stipulated budget for the subprogram is $145 million. Nonetheless, Pegasus concludes that "PSE&G has spent approximately 56% of both its estimated and currently forecasted recloser costs, suggesting actual costs coming in close to the estimate, but will warrant continued monitoring to ensure the subprogram objectives are completed within the estimated costs."	The overall change in the Contingency Reconfiguration subprogram forecast from the first to fourth quarter of 2020 was driven predominantly by changes in the scope of the subprogram (i.e. number of reclosers planned) and an evolving forecast of the Fuse Saver scope (initially only partially forecasted, then full forecasted, and more recently updated based on the experience of the pilot program). See also the response to RCR-INF-10 above.	No change

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2021 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

~~NOVEMBER 30, 2021~~

JANUARY 20, 2022

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Key Decisions 3
B. Program Management 4
C. Cost Assignments 4
D. System Performance 8
III. Project Status 11
A. Electric Station Flood Mitigation 11
B. Contingency Reconfiguration 24
C. Grid Modernization – Communication System 27
D. Grid Modernization – ADMS 30
E. Electric Stipulated Base 32
F. Gas M&R Station Upgrades 35
IV. Additional Information Following the End of the First Quarter of 2021 39
A. Decisions Recorded After the First Quarter of 2021 39

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS
Advanced Metering Infrastructure ..... AMI
Allowance for Funds Used During Construction ..... AFUDC
Architecture/Engineer ..... A/E
Board of Public Utilities ..... BPU
Construction Work In Progress ..... CWIP
Costs of Removal ..... COR
Department of Community Affairs ..... DCA
Distributed Energy Resource Management System ..... DERMS
Distribution Management System ..... DMS
Distribution Supervisory Control and Data Acquisition ..... DSCADA
Energy Strong 2 ..... ES 2
Gas Metering & Regulating ..... Gas M&R
Geographic Information System ..... GIS
Independent Monitor ..... IM
Inside Plant ..... IP
Issued for Construction ..... IFC
Liquid Propane Air ..... LPA
New Jersey Department of Environmental Protection ..... NJDEP
New Jersey Sports & Exposition Authority ..... NJSEA
Open Systems International Inc. ..... OSII
Outage Management System ..... OMS
Outside Plant ..... OP
Public Service Electric & Gas ..... PSE&G
Purchase Orders ..... POs
Record of Decision ..... ROD
Remote Control Unit ..... RCU
Remote Terminal Unit ..... RTU
Risk and Contingency ..... R&C

Soil Conservation District ..... SCD

System Average Interruption Duration Index ..... SAIDI

Supervisory Control and Data Acquisition ..... SCADA

Transmission & Distribution ..... T&D

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the first quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed five additional fiber installation projects and three additional fiber cutover projects in-service and continued the ramp-up of the retrofit recloser installations, with 749 units completed through the end of the first quarter of 2021 out of a current forecast of 2,449 units. The Grid Modernization – ADMS subprogram continued to plan and develop the platform and necessary hardware equipment, while the Gas M&R subprogram continued advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. The four stations approved within the life cycle upgrades portion of the Electric Stipulated Base continued design activities, including receipt of vendor drawings and advancing licensing and permitting packages. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2021

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	**$15,984,038**	**$69,929,211**	**$331,509,117**	**21%**	**Sep 2024**	**$389M**
Contingency Reconfiguration	**$12,503,156**	**$72,139,201**	**$148,927,422**	**48%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$6,306,330**	**$25,526,835**	**$58,602,845**	**44%**	**Dec 2023**	**$72M**
Grid Modernization – ADMS	**$2,488,981**	**$18,972,817**	**$40,375,507**	**47%**	**Oct 2022**	**$35M**
Electric Stipulated Base	**$1,350,398**	**$3,786,460**	**$100,000,000**	**4%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$2,019,800**	**$5,981,294**	**$91,199,999**	**7%**	**Dec 2023**	**$101M**
Total*	**$40,652,703**	**$196,335,818**	**$770,614,891**	**22%**	**Sep 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 12 and **Table 21** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2020**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2020

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$4,753,887	45%	10/25/2021
2. Clay Street	$42,000,000	$1,560,778	4%	2/7/2023 (↓)
3. Constable Hook	*Identified for Removal from the ES 2 Program*			
4. Hasbrouck Heights	$18,000,000	$1,830,577	10%	2/7/2023 (↑)
5. Kingsland	$8,300,000	$344,400	4%	10/4/2023
6. Lakeside Avenue	$47,900,000	$781,910	2%	12/13/2023
7. Leonia	$32,200,000	$8,887,799	28%	9/30/2022
8. Market Street	$26,900,000	$20,366,674	76%	9/23/2021 (↓)
9. Meadow Road	$9,000,000	$715,881	8%	9/21/2023
10. Orange Valley	$20,200,000	$447,215	2%	12/12/2023 (↑)
11. Ridgefield 13kV	$25,500,000	$9,654,641	38%	10/28/2022 (↓)
12. Ridgefield 4kV	$19,500,000	$14,191,713	73%	5/28/2021
13. State Street	$45,100,000	$977,153	2%	9/23/2022
14. Toney's Brook	$18,800,000	$673,983	4%	4/21/2023
15. Waverly	$35,400,000	$3,224,135	9%	9/17/2024 (↓)
16. Woodlynne	$19,400,000	$1,386,467	7%	10/10/2023 (↑)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As indicated in **Table 2**, the projects that have previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest spend. Additionally, two of the stations (Toney's Brook and Ridgefield 4kV) had new estimates approved by the Utility Review Board (URB) in during the first quarter of 2021. **Table 2** also shows that seven of the fifteen remaining projects in this subprogram (following the removal of Constable Hook) had movement in the forecasted in-service date, with three advancing and four slipping. Of these seven projects, three of the projects (Market Street, Clay Street, and Woodlynne) had forecasted in-service dates change by one day. Only two (Hasbrouck Heights and Waverly) had movement more than 60 days, which is the threshold the Independent Monitor (IM) applied during the original Energy Strong Program for evaluating changes to the project schedules. The Hasbrouck Heights forecasted in-service date previously moved in the fourth quarter of 2020 from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens GIS installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022, with no expected cost impacts from this schedule shift. The fourth quarter in-service date was based on the capacitor bank in-service date (April 2023), which has now been updated by PSE&G to reflect the switchgear in-service date currently forecasted for February 2023. The Waverly in-service date slipped

314 days from the forecasted in-service date at the end of the prior quarter. This was due to PSE&G being denied approval of the site plan by the Newark Planning Board, which requires PSE&G to address the comments received, coordinate community meetings on the new site plan application, and re-submit to the Newark Planning Board.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. With schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date as discussed in **Section III**, the ES 2 Program Schedule will warrant further monitoring by the IM to ensure the Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On November 30, 2021, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 First Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network – ESII-GM-3	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center– ESII-GM-4	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – Communication System	Fiber Scope – ESII-GM-1	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units – ESII-GM-2	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling – ESII-FM-1	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project – ESII-FM-Clay01	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers– ESII-CR-1	Reasonable and appropriate *(See **Section IV.A.** in this IM 2021 First Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation – ESII-GM-5	Under review *(See **Section IV.A.** in this IM 2021 First Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Costs of Removal as of March 31, 2021, below itemizes the charges to COR for the first quarter of 2021, the fourth quarter of 2020, and for comparative purposes, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 COR to date. These amounts do not reflect any salvage value reductions, which have been de minimis in the ES 2 Program through March 31, 2021.

Table 4 – ES 2 Costs of Removal as of March 31, 2021

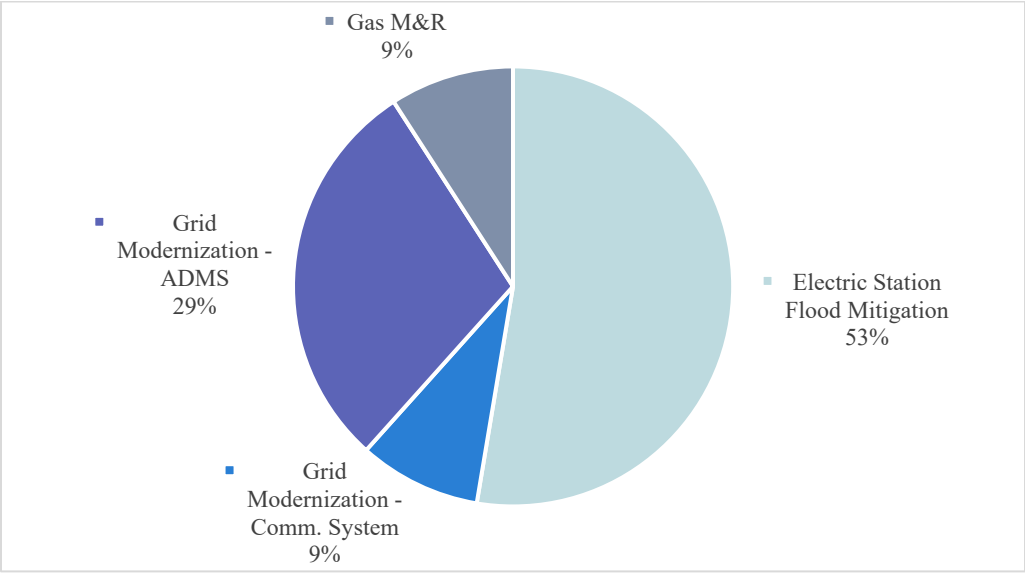
Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)				
Electric Station Flood Mitigation	**$1,129.5**	**$190.7**	**$1,021.1**	**$0**	**$2,150.6**
Contingency Reconfiguration	**$622.9**	**$707.3**	**$2,198.9**	**$431.0**	**$3,252.8**
Grid Modernization – Communications	**$37.8**	**$19.6**	**$24.4**	**$0**	**$62.2**
Grid Modernization - ADMS	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$1,790.2**	**$917.6**	**$3,244.4**	**$431.0**	**$5,465.6**

COR charges during the first quarter of 2021 increased substantially from the fourth quarter of 2020 primarily due to the removal of the 4kV overhead circuits and associated equipment at the Market Street substation project (about $1.0 million).

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

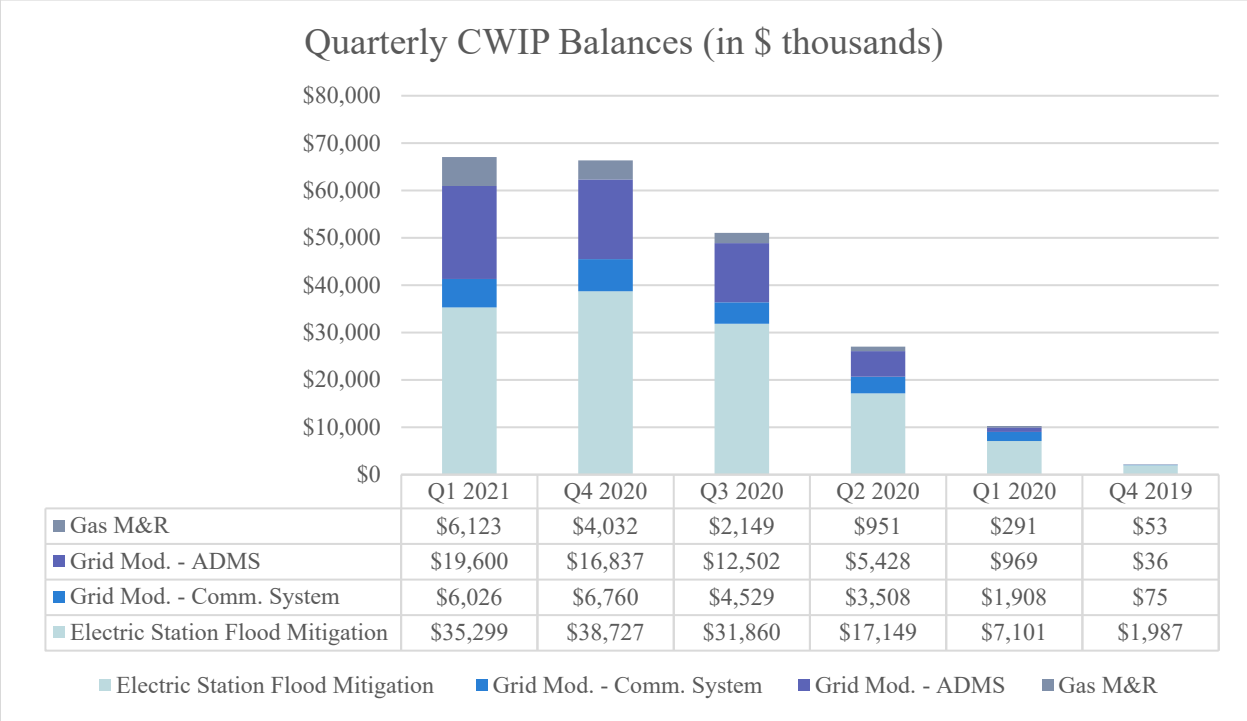
As of March 31, 2021, the ES 2 CWIP balance was $67.0 million, compared to $66.4 million as of December 31, 2020. The largest components of March 31, 2021 CWIP were the elimination and conversion of the 4kV circuits at the Ridgefield ($9.1 million) and Market Street substations ($5.1 million), activity at Academy Street substation ($5.0 million) and work associated with the Grid Modernization – ADMS subprogram ($19.6 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of March 31, 2021** below.

Figure 1 – ES 2 CWIP as of March 31, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the first quarter of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2021



	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas M&R	$6,123	$4,032	$2,149	$951	$291	$53
Grid Mod. - ADMS	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Mod. - Comm. System	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in-service totaled $12.2 million during the first quarter of 2021, mainly comprised of $9.5 million of switchgear assets at the Leonia and Ridgefield 13kV substations. Total ES 2 transfers from CWIP have been $17.4 million through March 31, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is fully in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the first quarter of 2021, the fourth quarter of 2020 (for comparative purposes), total AFUDC for the years 2020 and 2019 and total ES 2 AFUDC accrued to date, is shown below in **Table 5 – ES 2 AFUDC as of March 31, 2021**.

Table 5 – ES 2 AFUDC as of March 31, 2021

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Electric Station Flood Mitigation	**$558.6**	**$305.0**	**$936.5**	**$9.9**	**$1,505.0**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Grid Modernization – Communications	**$59.0**	**$66.2**	**$184.3**	**$0.2**	**$243.5**
Grid Modernization - ADMS	**$274.2**	**$213.9**	**$352.7**	**$0.1**	**$627.0**
Electric Stipulated Base	**$49.6**	**$32.6**	**$44.0**	**$0**	**$93.6**
Gas M&R Station Upgrades	**$72.2**	**$39.6**	**$70.0**	**$0.2**	**$142.4**
Total	**$1,013.6**	**$657.3**	**$1,587.5**	**$10.4**	**$2,611.5**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2021, based on data as of March 31, 2021, the recalculated weighted average AFUDC accrual rate (6.79%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the first quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for ES 2 projects during the first quarter of 2021 increased over AFUDC accrued during the fourth quarter of 2020 as the result of the reclassification made to CWIP and AFUDC during the fourth quarter of 2020 to reflect the reversal of certain costs from CWIP to plant in-service, with the associated effect on fourth quarter 2020 AFUDC (as discussed in the IM's Fourth Quarter 2020 Report), the semiannual AFUDC compounding roll-in to the AFUDC base calculation that occurs in January of each year, and increases in total average CWIP balances for the Grid Modernization – ADMS and Gas M&R subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to first quarter 2021 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity

receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Overhead Allocations as of March 31, 2021** are the allocated overhead costs charged to ES 2 projects for the first quarter of 2021, the fourth quarter of 2020 (for comparative purposes), total 2020, total 2019 and total Energy Strong allocated overheads to date.

Table 6 – ES 2 Overhead Allocations as of March 31, 2021

Subprogram	Q1 2021	Q4 2020	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)				
Electric Station Flood Mitigation	**$5,588**	**$4,925**	**$14,023**	**$287**	**$19,898**
Contingency Reconfiguration	**$4,215**	**$6,011**	**$17,109**	**$3,415**	**$24,739**
Grid Modernization – Communications	**$1,743**	**$2,170**	**$3,625**	**$12**	**$5,380**
Grid Modernization – ADMS	**$119**	**$112**	**$426**	**$11**	**$556**
Electric Stipulated Base	**$126**	**$104**	**$259**	**$0**	**$385**
Gas M&R Station Upgrades	**$131**	**$92**	**$291**	**$15**	**$437**
Total*	**$11,922**	**$13,414**	**$35,733**	**$3,740**	**$51,395**

The overwhelming majority of overhead costs allocated to ES 2 projects during the first quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES2 projects. More specifically, most of the first quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overheads for the first quarter 2021 from the fourth quarter of 2020 largely reflects lower overall ES 2 project spend, notably in the Contingency Reconfiguration subprogram.

D. System Performance

1. Current Reporting Quarter Major Events

During the first quarter of 2021, there was one Major Event reported in PSE&G's service territory concerning a State of Emergency declared due to a series of snowstorms. The State of Emergency was declared by Governor Murphy on January 31, 2021 and was lifted on February 23, 2021. During this Major Event period, 104,932 PSE&G customers experienced extended service.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q1 2021 Major Event Performance** below.

ENERGY STRONG 2 – INDEPENDENT MONITOR
~~Draft~~ *2021 First Quarter Report*
CONFIDENTIAL

Table 7 – Q1 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8026		0.00000
BAO 8006		0.00000
BAO 8008	**0.00005**	**0.00036**
BEF 8015	**0.00433**	**0.01158**
BEN 8012	0.22864	0.00548
BLO 4016	**0.01635**	**0.12393**
BRU 8012	0.01648	0.00000
BRU 8022	0.02954	0.00313
BRU 8023		**0.01247**
BUS 8023	0.03965	0.00000
CAS 8001	0.02438	0.00391
CED 8022	0.05071	0.00646
CIN 8002	0.01418	0.00000
CIN 8043	0.18459	0.00946
CLF 8024	0.01800	0.00000
CLK 8023	0.00019	0.00000
CLK 8024	0.01526	0.00000
COR 8034	0.03335	0.00000
COR 8041	0.05596	0.00000
CRX 8003	0.07703	0.00247
CUT 8006	0.59550	0.00052
CUT 8007	0.67234	0.01577
CUT 8010	0.49117	0.02914
CUT 8031	0.00845	0.00000
DFD 8007	0.06056	0.01571
EAT 8023		**0.00363**
FAW 8023	0.02811	0.00117
FED 4021		**0.02426**
FIT 8003	0.01301	0.00538
FOU 8014	**0.00123**	**0.00690**
FOU 8022	**0.00091**	**0.00180**
FOU 8024		**0.00402**
GBK 8014	0.30784	0.00027
GBK 8025	0.31504	0.00145
HAC 4007		0.00000
HAT 8015	0.02090	0.00181
HAT 8035	0.04291	0.00026
HNC 8015	0.15427	0.00340
HNC 8024	0.43454	0.00282
HOE 8047	0.05561	0.04167
IRO 4003		0.00000
IRO 4005		0.00000
IRO 4011		0.00000
IRO 4012		0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
IRO 4014		0.00000
IRV 4013	**0.02207**	**0.03411**
JAC 8021	0.00477	0.00090
JAC 8022	0.04453	0.00030
JAC 8024	0.25423	0.00000
JAC 8033	**0.00350**	**0.00819**
KIL 8014		**0.00821**
KIL 8016	0.01491	0.00000
KIL 8023		**0.02076**
KIL 8024	0.01504	0.00212
KIL 8033	0.01648	0.01115
KIL 8042	0.06155	0.00000
KUS 8009	**0.04178**	**0.05447**
LAW 8016	0.14895	0.00804
LAW 8025	0.16759	0.00894
LAW 8033	0.04306	0.00000
LCU 8051	0.19366	0.01809
LEO 8005	0.61152	0.01045
LEO 8006	0.07368	0.00000
LEV 8002	0.06064	0.05175
LEV 8011	0.25139	0.00457
LEV 8012	0.25318	0.00449
LIB 4007**	0.10880	0.01004
LIT 8001	0.02586	0.00000
LOC 8012		**0.00993**
LUM 8024	0.23063	0.00164
MAD 8018	0.20763	0.00118
MAD 8022	0.41375	0.00156
MAD 8024	0.11054	0.00000
MAI 8013	0.05318	0.01301
MAR 8017	0.45014	0.00683
MAY 8013		**0.00155**
MDF 8012	0.58371	0.00080
MDF 8023	0.26488	0.00110
MEA 8024	0.09438	0.03566
MIN 8024		0.00000
MIN 8025	**0.00515**	**0.01043**
MTL 8015	0.04117	0.00308
NBS 8023	0.00085	0.00000
NED 8013	0.03270	0.00000
NED 8025	0.01640	0.01087
NEW 8014	0.01839	0.00098
NIN 4004	0.03196	0.00131
NOT 8011		**0.00307**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
NOT 8013		0.00000
NOT 8014	0.00232	0.00000
NOT 8021		**0.00017**
NOT 8022	**0.00091**	**0.02397**
NRB 8012		**0.00574**
ORA 4001	0.02674	0.02302
PEK 8026	0.04523	0.00101
PIE 8023	0.04636	0.01156
PIN 4002**	0.08187	0.00000
PLI 8005	0.16440	0.00000
POH 8012		**0.00016**
POR 8021**		0.00000
RAV 8003	0.00674	0.00008
RFL 8025		0.00000
RGW 4007		**0.00800**
RUN 8001		**0.01054**
SAD 8002		**0.00115**
SAD 8045	**0.00284**	**0.02276**
SMV 8012		**0.01636**
SPF 8025	0.09408	0.00000
SUN 8045	**0.00066**	**0.00073**
TUR 8001	**0.00248**	**0.00976**
TUR 8015	**0.00704**	**0.04733**
VIL 8001**	0.24055	0.00000
WAD 8011	0.08512	0.02907
WAN 8015		**0.00201**
WAN 8022		**0.00214**
WEW 8014		**0.00093**
WEW 8042	0.01304	0.00249
WOR 8021		0.00000
WOR 8034	0.01023	0.00207

**-SAIDI calculations are in minutes.*
***-These circuits have not received investments under the Original Energy Strong Program or under the ES 2 Program, all other circuits listed have received investments.*

In the circuit data above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G; in addition, blank cells indicate no outage in the 5-year window. As indicated above, there were 119 circuits impacted by this Major Event with the majority of the affected circuits having experienced outages less the 5-year Major Event average.

For those circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average (shown in bold in **Table 7**), 19 had no outages in the past five years while 14 had a higher report quarter SAIDI average than the 5-year baseline SAIDI. For those 14, additional information on the circuits and the outage experienced is provided below in **Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits** (note that some of these circuits had more than one incident during the Major Event, resulting in a total of 24 incidents from these 14 circuits).

Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BAO 8008	0.00005	0.00036	47	19
BEF 8015	0.00433	0.01158	569	50
BLO 4016	0.01635	0.12393	473	171
BLO 4016	0.01635	0.12393	1,254	171
BLO 4016	0.01635	0.12393	0	356
BLO 4016	0.01635	0.12393	17	171
BLO 4016	0.01635	0.12393	18	171
BLO 4016	0.01635	0.12393	0	171
BLO 4016	0.01635	0.12393	19	171
FOU 8014	0.00123	0.00690	0	168

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
FOU 8014	0.00123	0.00690	47	47
FOU 8014	0.00123	0.00690	117	126
FOU 8022	0.00091	0.00180	85	52
IRV 4013	0.02207	0.03411	1,035	81
JAC 8033	0.00350	0.00819	117	172
KUS 8009	0.04178	0.05447	631	154
KUS 8009	0.04178	0.05447	1,930	19
MIN 8025	0.00515	0.01043	39	657
NOT 8022	0.00091	0.02397	1,636	36
SAD 8045	0.00284	0.02276	948	59
SUN 8045	0.00284	0.02276	948	59
TUR 8001	0.00248	0.00976	101	129
TUR 8001	0.00248	0.00976	85	129
TUR 8015	0.00704	0.04733	1,077	108
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, whether it be different device operations (fuse with 10 customers vs. fuse with 150 customers) than the Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the first quarter of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of March 31, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of March 31, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
	Mar. 2021		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
	Mar. 2021			KO							C					IS				CO (Q2)
3. Constable Hook	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020	*Schedule Under Development*																		
	Mar. 2021	*Identified for Removal from the ES 2 Program*																		

ENERGY STRONG 2 – INDEPENDENT MONITOR
~~Draft~~ *2021 First Quarter Report*
CONFIDENTIAL

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Mar. 2021		KO									C				IS				CO (Q1)
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Mar. 2021			KO											C				IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Mar. 2021						KO							C					IS	CO (Q4)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Mar. 2021			KO		C								IS			CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Mar. 2021			KO					C/OS					CO						
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Mar. 2021			KO										C				IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Mar. 2021					KO								C					IS	CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Mar. 2021			KO	C										IS			CO		
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Mar. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Mar. 2021		KO						C					IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Mar. 2021			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Mar. 2021			KO			C													IS (Q3); CO (Q1 2025)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Mar. 2021		KO												C				IS	CO (Q2)

Dec. 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout

-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).

*-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.

A summary of the subprogram status as of the end of the first quarter of 2021 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	15*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architecture/Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	15	Academy Street[1]; Clay Street[1]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start^	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 15 switchgears at 12 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
^-Includes inside plant and/or outside plant construction.

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2021** summarizes the planned activities for each project during the second quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2021

Station	Upcoming Activities for Q2 2021	Carryover Activities from Q1 2021
1. Academy Street	• Continued engineering and construction	• Continued engineering and construction
2. Clay Street	• 70% estimate completed • Civil, controls, and electrical drawings issued for construction (IFC)	• None
3. Constable Hook	• Identified for Removal from the ES 2 Program	
4. Hasbrouck Heights	• Electrical construction PO issued • Major municipal licenses and permits issued	• None
5. Kingsland	• Continued design and engineering	• Continued design and engineering
6. Lakeside Avenue	• License and permitting packages issued (site plan application)	• None

Station	Upcoming Activities for Q2 2021	Carryover Activities from Q1 2021
7. Leonia	• Phase 3 municipal licenses and permits issued (site plan, construction) • Switchgear delivered • Phase 2 civil construction complete • Phase 2 electrical construction start	• None
8. Market Street	• In-service achieved for 4kV to 13kV circuit conversions and outside plant Deptford street and Locust street extensions	• None
9. Meadow Road	• Continued engineering and design	• Continued engineering and design
10. Orange Valley	• Switchgear PO issued	• License and permitting package issued
11. Ridgefield 13kV	• Switchgear delivered • Major state and municipal licenses and permits issued (piles/foundation) • Phase 1 civil construction start	• None
12. Ridgefield 4kV	• Civil demolition PO issued • Electrical construction completed • In-service achieved for 4kV to 13kV circuit conversions • Start electrical demolition	• None
13. State Street	• 70% estimate completed • Civil PO issued • Controls drawings IFC	• Electrical construction purchase order issued
14. Toney's Brook	• Electrical construction PO issued • Civil and electrical drawings IFC	• None
15. Waverly	• Switchgear delivered • Phase 2 controls drawings IFC	• None
16. Woodlynne	• 70% estimate completed • Civil and electrical POs issued • Major municipal licenses and permits issued (construction)	• None

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the first quarter of 2021.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,217	$4,753,887	45%
2. Clay Street	Study	$34,800,000	$7,200,000	$42,000,000	$29,796,949	$1,560,778	4%
3. Constable Hook	*Identified for Removal from the ES 2 Program*						

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
4. Hasbrouck Heights	Study	$14,900,000	$3,100,000	$18,000,000	$20,474,628	$1,830,577	10%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,541	$344,400	4%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,278	$781,910	2%
7. Leonia	Study	$27,700,000	$4,500,000	$32,200,000	$25,082,905	$8,887,799	27%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$26,174,479	$20,366,674	76%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,325,880	$715,881	8%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,703,933	$447,215	2%
11. Ridgefield 13kV	Study	$19,600,000	$5,900,000	$25,500,000	$25,256,853	$9,654,641	38%
12. Ridgefield 4kV	Definitive	$18,500,000	$1,000,000	$19,500,000	$18,829,711	$14,191,713	73%
13. State Street	Study	$39,000,000	$6,100,000	$45,100,000	$38,928,940	$977,153	4%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,205,945	$673,983	4%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$33,806,170	$3,224,135	9%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$18,308,852	$1,386,467	7%
Subprogram Total		**$318,900,000**	**$59,800,000**	**$378,700,000**	**$331,374,281**	**$69,797,213**	**14%**

Findings & Observations

- Seven Electric Station Flood Mitigation projects had changes to the forecasted in-service date from the end of 2020 to the end of the first quarter of 2021. Of these projects: Market Street, Clay Street, and Woodlynne had a one-day move in the forecasted in-service date; Ridgefield 13kV slipped 15 days; and Orange Valley improved 43 days. Two other projects had forecasted in-service movements greater than 60 days, including Hasbrouck Heights, which improved 64 days based on PSE&G identifying the in-service date as the final major asset (which is consistent with PSE&G's treatment of other Electric Station Flood Mitigation in-service dates across Energy Strong and ES 2) instead of the previously identified date of when the capacitor banks were completed, and Waverly, which slipped 314 days stemming from delays in approval of the site plan application that pushed out construction to 2022 and the last major asset in-service to September 2024, substantially beyond the ES 2 Program completion date of December 31, 2023.

- The Ridgefield 4kV and Toney's Brook projects had new estimates approved during the first quarter of 2021, each resulting in a minor decrease to the overall estimate for the project. The Ridgefield 4kV project advanced from the Conceptual to Definitive estimate phase, with an overall decrease of $0.7 million from the prior estimate for a total estimate of $19.5 million. The Toney's Brook project advanced from the Study to Conceptual estimate phase, with an overall decrease of $0.9 million from the prior estimate for a total estimate of $18.8 million.
- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the IM finds that the Waverly project is currently scheduled beyond the ES 2 Program completion date. The status of the later projects in this subprogram, and in particular Waverly, will have to closely be followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the first quarter of 2021, the Waverly project shows a final in-service date of September 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers. At this time Transformer #3 is the outlier from completing the full scope within the ES 2 Program window. PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM has increased its monitoring on the projects that are currently forecasted to be completed in the fourth quarter of 2023 and the Waverly project and will continue to discuss with PSE&G actions undertaken to improve schedule, for which updated information will continue to be provided in future IM reports.

1. Academy Street

During the first quarter of 2021, $378,939 was spent on the Academy Street project compared to a forecast of approximately $470,000, which brought the total spend to approximately $4.7 million. The variance in first quarter spend was largely driven by completion of the 69kV underground duct bank pushing out remaining ES 2 work and delivery of substation steel slipping from March to April. The forecasted in-service date for the Academy Street project remains at October 25, 2021, which is unchanged from the previous quarter.

The primary activity conducted during the first quarter of 2021 on the Academy Street project included the commencement of 4kV to 13kV conversion pre-work. Construction, which started in July 2020 for non-permit work on Academy Street, remains at 65% complete inside plant, while the total project is reported at 77% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$150,398	$4,224,550	$378,939	$443,324	$738,947	$1,687,021	$2,081,037

Actuals to Date	Estimate	% of Actuals to Estimate
$4,753,887	$10,500,000	45%

2. Clay Street

During the first quarter of 2021, $565,030 was spent on the Clay Street project compared to a forecast of approximately $570,000, which brought the total spend to approximately $1.6 million. At the beginning of the quarter, there was the potential for delay on the site plan approval stemming from the planning board's Covid-19 protocols. However, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021 and resulted in the approval of the site plan.

Also in the first quarter of 2021, PSE&G's accounting group made the determination that the sanitation wall on the Clay Street project is both a transmission and distribution asset. This is resulting in a scope change that will remove this scope of work from the ES 2 project and add it to the 69kV project. The final details have yet to be reported to the IM, but no schedule impacts are expected from this change, while the costs to the ES 2 project will be slightly reduced.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$116,409	$879,339	$565,030	$1,103,119	$205,080	$8,590,291	$18,337,680

Actuals to Date	Estimate	% of Actuals to Estimate
$1,560,778	$42,000,000	4%

3. Constable Hook

As discussed in the IM 2020 Fourth Quarter Report, this project has been identified to be removed from the ES 2 Program and replaced with the Front Street project. Should the Front Street project be approved for inclusion in the ES 2 Program, it will be covered in this section, otherwise a placeholder will remain here to maintain consistency in the project/section numbering throughout future IM reports.

The actual spend for Constable Hook as compared to the URB approved estimate is provided below. PSE&G has informed the IM it will be removing the actual costs associated with the Constable Hook project from ES 2.

Actuals to Date	Estimate	% of Actuals to Estimate
$115,640	$5,300,000	2%

4. Hasbrouck Heights

During the first quarter of 2021, $550,796 was spent on the Hasbrouck Heights project compared to a forecast of approximately $612,000, which brought the total spend to approximately $1.8 million. Notable activities completed during the fourth quarter of 2020 included:

- Civil and electrical construction packages out for bid;
- Contingency plan electrical layout completed; and,
- State Department of Community Affairs (DCA) permit received.

As reported in the IM 2020 Third Quarter Report, a Covid-19 related delay on the associated Hasbrouck Heights 69kV project resulted in a delay to the Hasbrouck Heights ES 2 project. In the IM 2020 Fourth Quarter Report it was reported that this delay shifted the forecasted in-service date to April 2023 (was previously November-December 2022). PSE&G since identified that the April 2023 forecasted in-service date reflected the capacitor bank in-service date, with the project in-service date now updated to February 2023 as that is reflective of the switchgear in-service date.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The total project forecast increased from approximately $17.9 million as of the end of 2020 to $20.5 million as of the end of the first quarter of 2021, which was primarily driven by civil construction bids coming in higher than estimated ($1.2 million) and higher dewatering estimates based on site conditions ($1.3 million).

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$149,848	$1,129,934	$550,795	$1,146,217	$254,070	$4,584,100	$12,659,663

Actuals to Date	Estimate	% of Actuals to Estimate
$1,830,577	$18,000,000	10%

5. Kingsland

During the first quarter of 2021, $30,621 was spent on the Kingsland project compared to a forecast of $42,000, which brought the total spend to $344,400. There continued to be minimal activities performed on this project during the first quarter of 2021.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$104,112	$209,667	$30,621	$42,000	$83,542	$307,674	$5,640,925

Actuals to Date	Estimate	% of Actuals to Estimate
$344,400	$8,300,000	4%

6. Lakeside Avenue

During the first quarter of 2021, $178,973 was spent on the Lakeside Avenue project compared to a forecast of approximately $73,000. The variance in first quarter spend was largely driven by the early completion of the key drawing package milestone that was previously forecasted for May 2021. Other notable activities completed during the first quarter of 2021 included the issuance of the switchgear PO.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$148,943	$453,994	$178,973	$190,952	$111,167	$241,028	$38,031,221

Actuals to Date	Estimate	% of Actuals to Estimate
$781,910	$47,900,000	2%

7. Leonia

During the first quarter of 2021, approximately $2.8 million was spent on the Leonia project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $8.9 million. The variance in first quarter spend was primarily the result of the in-service date of the temporary switchgear advancing and cable and conduit relocation work not forecasted but needed to be completed to prepare the switchgear foundation in advance of the switchgear delivery. Other notable activities completed during the first quarter of 2021 included:

- Civil and electrical construction phases 2/3 out for bid and PO issued;
- State DCA permit (phase 2) received; and,
- Conceptual level estimate completed.

Construction at Leonia, which started in August 2020, has advanced to 38% complete inside plant as of the end of the first quarter of 2021, up from 35% complete as of the end of 2020, with the total project reported at 46% complete.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The total project forecast decreased from approximately $30.4 million as of the end of 2020 to approximately $25.1 million as of the end of the first quarter of 2021, which was driven by civil and electrical construction awards coming in lower than estimated.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$44,792	$6,033,379	$2,809,628	$4,243,320	$1,475,002	$1,478,341	$8,998,442

Actuals to Date	Estimate	% of Actuals to Estimate
$8,887,799	$32,200,000	27%

8. Market Street

During the first quarter of 2021, $4,035,880 was spent on the Market Street project compared to a forecast of approximately $3.8 million, which brought the total spend to approximately $20.3 million. Notable activities completed during the first quarter of 2021 included the receipt of the Soil Conservation District (SCD) permit.

Construction at Market Street, which started in August 2020, advanced to 75% complete outside plant as of the end of the first quarter of 2021, up from 60% as of the end of 2020. Inside plant construction is anticipated to begin in September 2021 and the overall project is reported at 64% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$251,193	$16,079,601	$4,035,880	$3,064,249	$1,452,036	$1,138,089	$153,432

Actuals to Date	Estimate	% of Actuals to Estimate
$20,366,674	$26,900,000	76%

9. Meadow Road

During the first quarter of 2021, $117,672 was spent on the Meadow Road project compared to a forecast of $94,000, which brought the total spend to approximately $716,000. The New Jersey Department of Environmental Protection (NJDEP) Flood Hazard Area permit was submitted during the first quarter of 2021 and there were minimal other activities on the Meadow Road project during the first quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$63,128	$535,081	$117,672	$84,000	$69,000	$79,000	$6,377,998

Actuals to Date	Estimate	% of Actuals to Estimate
$715,881	$9,000,000	8%

10. Orange Valley

During the first quarter of 2021, $7,291 was spent on the Orange Valley project compared to a forecast of approximately $152,000, which bought the total spend to approximately $447,000. The variance in first quarter spend was largely the result of the project re-allocating an engineering invoice between this ES 2 project and the 69kV project that had incorrectly been included in the ES 2 project forecast, along with less project management, engineering, and permitting spend compared to the forecast. There were minimal activities on the Orange Valley project during the first quarter of 2020, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$77,029	$362,895	$7,291	$125,588	$333,622	$271,428	$14,526,081

Actuals to Date	Estimate	% of Actuals to Estimate
$447,215	$20,200,000	2%

11. Ridgefield 13kV

During the first quarter of 2021, $3,215,967 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.6 million, which brought the total spend to approximately $9.7 million. The variance in first quarter spend was largely the result of additional work required to support the temporary switchgear going in-service and the Division pulling more cable than anticipated to keep progress on the project and to meet the demolition timeframe requirements. Notable activities completed during the first quarter of 2021 included:

- Temporary switchgear placed in-service;
- Phase 2 civil and electrical drawings IFC; and,
- New Jersey Sports & Exposition Authority (NJSEA) piles/foundation permits received.

Construction at Ridgefield 13kV remained at a reported 33% complete inside plant as of the end of the first quarter of 2021, with the total project at a reported 40% completion.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$205,982	$6,232,692	$3,215,967	$3,366,788	$2,326,500	$1,697,213	$8,211,711

Actuals to Date	Estimate	% of Actuals to Estimate
$9,654,641	$25,500,000	38%

12. Ridgefield 4kV

During the first quarter of 2021, $2,808,765 was spent on the Ridgefield 4kV project compared to a forecast of approximately $4.8 million, which brought the total spend to approximately $14.2 million. The variance in first quarter spend was driven by the outside plan manhole rebuilding being delayed due to bids received later than expected and Division cable pulling postponed due to weather and more urgent work performed on the Ridgefield 13kV project that shifted the available resources. With the resources for both the Ridgefield 4kV and Ridgefield 13kV projects limited due to weather impacts, allocating the available resources to the Ridgefield 13kV project maintained that project's critical path with no impact to the Ridgefield 4kV critical path. Activities completed during the first quarter of 2021 on the Ridgefield 4kV project included the civil and electrical demolition drawings IFC.

Construction at Ridgefield 4kV, which started in June 2020, has advanced to 88% complete, up from 72% at the end of 2020. The total project is reported at 81% complete as of the end of the first quarter of 2021.

In March 2021, the Definitive level estimate was submitted and approved before the URB. This Definitive level estimate reduced the total Ridgefield 4kV project estimate to $19.5 million from the previously approved $20.2 million, which included an increase to the base estimate ($0.9 million) that was offset by a reduction to R&C (-$1.6 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Additional manhole rebuild work ($0.8 million);
- Additional underground cable and overhead switching procedures ($0.5 million);

- Higher costs for paving and cable pulling ($0.4 million); and,
- Less Division contractor surcharges (-$0.8 million).

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$143,414	$11,239,534	$2,808,765	$3,036,469	$1,460,530	$81,000	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$14,191,713	$19,500,000	73%

13. State Street

During the first quarter of 2021, $237,415 was spent on the State Street project compared to a forecast of approximately $210,000, which brought the total spend to approximately $977,000. The activities performed on State Street during the first quarter of 2021 primarily related to advancing the engineering work in preparation of the start of civil construction in the second quarter.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$77,590	$662,148	$237,415	$767,376	$6,240,801	$1,119,853	$29,823,756

Actuals to Date	Estimate	% of Actuals to Estimate
$977,153	$45,100,000	2%

14. Toney's Brook

During the first quarter of 2021, $88,947 was spent on the Toney's Brook project compared to a forecast of approximately $89,000, which brought the total spend to approximately $674,000. Notable activities completed during the first quarter of 2021 included the electrical construction work going out for bid.

In February 2021, the Conceptual level estimate was submitted and approved before the URB. This Conceptual level estimate reduced the total Toney's Brook project estimate to $18.8 million from the previously approved $19.7 million, which included an increase to the base estimate ($1.9 million) that was offset by a reduction to R&C (-$2.8 million). The reduction to R&C was driven by the current view of the risk profile on the project while the changes to the base estimate were driven by:

- Higher concrete quantities ($0.9 million);
- Changing in T&D surcharge methodology ($0.6 million); and,
- Switchgear award higher than estimated ($0.4 million).

The change in T&D surcharge methodology caused an increase in Outside Service Electrical construction planned surcharge rate which increased by over 45% from 2019 to 2020. As a result, approximately $587,000 of the $0.6 million increase on Toney's Brook Conceptual level estimate was attributed to increase in electrical construction. The remainder of the $0.6 million increase is associated with Project Management labor.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$211,940	$373,096	$88,947	$330,962	$200,548	$207,809	$14,792,644

Actuals to Date	Estimate	% of Actuals to Estimate
$673,983	$18,800,000	4%

15. Waverly

During the first quarter of 2021, $659,572 was spent on the Waverly project compared to a forecast of approximately $490,000, which brought the total spend to approximately $3.2 million. The variance in first quarter spend was largely driven by phase 1 civil construction and environmental progress advancing more than forecasted due to favorable weather conditions. Notable activities completed during the first quarter of 2021 included:

- Vendor drawings received (final switchgear arrangement and controls); and,
- Phase 2 electrical construction out for bid;

As with the Clay Street project, at the beginning of the quarter, there was the potential for delay on the site plan approval stemming from the planning board's Covid-19 protocols. However, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The comments received from the Newark Planning Board were generally aesthetic in nature (e.g. comments on why a green roof was not considered, art on exterior fence, height of lightning mast, etc.) and PSE&G is preparing to follow-up with a public workshop and meetings with the City to resolve the comments and prepare a revised site plan. The revised site plan is expected to be submitted in the coming months. Due to the site plan not being approved in the March 2021 meeting, the remaining aspects of the entire project have shifted out, including the commencement of phase 2 construction from May 2021 to a forecasted January 2022, commencement of phase 3 construction from February 2022 to October 2022, and pushing the final in-service date for Transformer #3 from the fourth quarter of 2023 to the third quarter of 2024 (the other in-service dates for the Waverly substation, including the other transformers, the 4kV switchgear, and the 26kV switchgear shifted from December 2022 to November 2023). PSE&G's preliminary estimate on the changes stemming from the revised site plan indicate a resulting cost increase of approximately $2.6 million to the project, which is driven by additional engineering, revised fencing and external façade improvements, and the extended project duration.

Construction at Waverly, with phase 1 having started in October 2020, advanced to 6% complete as of the end of the first quarter of 2021.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals			*Forecast*			
$103,748	$2,460,815	$659,572	$2,832,258	$562,468	$489,899	$26,697,409

Actuals to Date	Estimate	% of Actuals to Estimate
$3,224,135	$35,400,000	9%

16. Woodlynne

During the first quarter of 2021, $282,187 was spent on the Woodlynne project compared to a forecast of approximately $276,000, which brought the total spend to approximately $1.1 million. Notable activities completed during the fourth quarter of 2020 included the site plan resolution compliance achieved and State DCA permit received.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$110,982	$993,298	$282,187	$157,336	$1,429,454	$923,989	$14,411,606

Actuals to Date	Estimate	% of Actuals to Estimate
$1,386,467	$19,400,000	6%

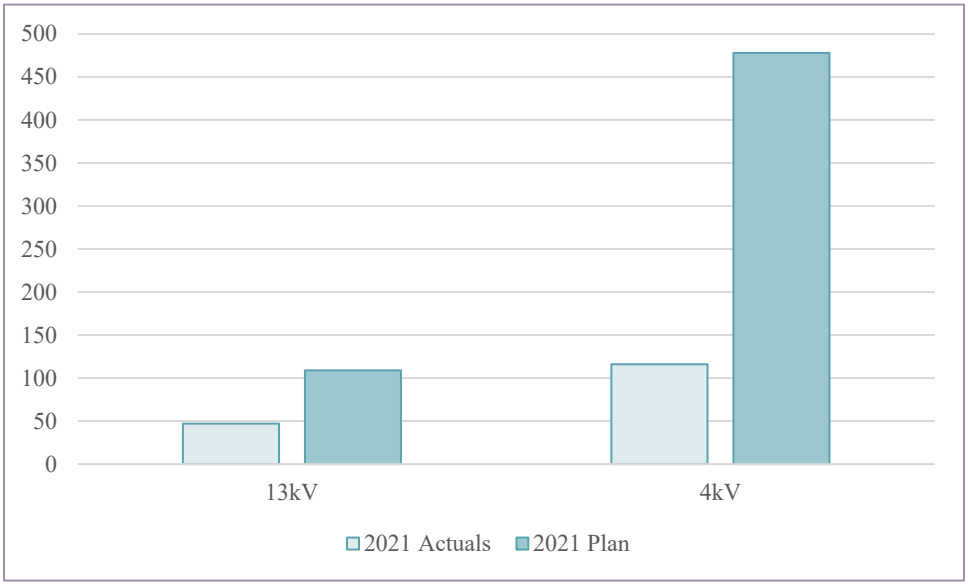
B. Contingency Reconfiguration

During the first quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 163 installed during the quarter and 167 commissioned. **Table 13 – ES 2 Recloser Status as of March 31, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of March 31, 2021** compares the installed reclosers as of the end of the first quarter of 2021 against PSE&G's 2021 installation plan.

Table 13 – ES 2 Recloser Status as of March 31, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q1 Qty.	*2021 Total*	*Program Total*	*Q1 Qty.*	*2021 Total*	*Program Total*	*Q1 Qty.*	*2021 Total*	*Program Total*
13kV	52	52	751	47	47	708	51	51	695
4kV	77	77	331	116	116	273	116	116	273
Total	129	129	1,082	163	163	981	167	167	968

Figure 3 – 2021 Recloser Installations as of March 31, 2021



As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. As also shown in **Table 13** and **Figure 3**, PSE&G maintained progress during the first quarter of 2021 and stayed on track for the 2021 plan despite some weather impacts and resource constraints in the Metro Division. The weather impacts were primarily 10 snow days during February and piles of snow at pole locations, which was recovered through the use of overtime and weekend work.[1] The resource constraints in the Metro Division stemmed from attrition at the end of the year and two larger projects in the Division with firm in-service dates, leading to a shortage of approximately 30 full-time equivalents compared to normal. While new hires have been brought on board, they will not be able to work on crews until their training is completed. To mitigate impacts, PSE&G engaged a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021 and will continue until the internal resources are available. PSE&G estimates that the cost of outsourcing the pole setting and preparation work in the Metro Division will result in a less than 1% increase to the cost per unit of the reclosers, or a total cost of approximately $784,000. By outsourcing this scope, PSE&G will allow the Metro Division recloser scope to complete earlier than it otherwise would, which avoids an estimated $100,000 in additional carrying costs and avoids additional resource constraints from the Fuse Saver work commencing in 2022 overlapping with the recloser work. ~~As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020.~~

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[2] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of

[1] As discussed in Appendix A to the IM 2020 Fourth Quarter Report (in response to RCR-INF-8), unitized work such as reclosers do not have a labor rate premium associated with weekend/overtime work. The schedule is made in advance and resources are planned accordingly in order to achieve the installation rate necessary to install the planned number of units within the scheduled timeframe, thus the cost per unit does not change provided all units planned for the period are completed.

[2] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote-control unit must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the remote control unit (RCU), wherein the supervisory control and data acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which have affected approximately 10% of the installed devices. The solution to resolve these communication issues includes modifying the external antenna (and modifying the RCU enclosure to accommodate the antenna). PSE&G will monitor the devices to ensure the identified solution~~it~~ addresses the issues prior to placing additional Fuse Saver orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021, as it awaits approval by PSE&G's Asset Management group to proceed with the full scope, aside from the installation of additional units from existing stock.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2021**. This table also shows the forecasted dates as of the end of 2020 to show movement to the forecast as of the end of the first quarter of 2021.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2021

Scope & Division		Q4 2020 Forecasted Completion Date	Q1 2021 Forecasted Completion Date
Reclosers	Central	9/30/2021	12/31/2021
	Metro	12/31/2021	12/31/2021
	Palisades	12/31/2021	11/30/2021
	Southern	12/31/2021	12/31/2021
Fuse Savers	Central	6/30/2023	12/30/2023
	Metro	6/30/2023	12/30/2023
	Palisades	5/31/2023	12/30/2023
	Southern	6/30/2023	12/30/2023

As shown in **Table 14**, the forecasted completion for each Division's Fuse Saver program slipped approximately six months, which was driven by a delay to the start of this scope while PSE&G evaluates the performance of the devices installed in the Fuse Saver pilot program. The three-month slippage of the Central Division recloser scope was driven by additional units added to the scope. The one-month advancement in the Palisades Division recloser scope was driven by schedule adjustments that reflected increased monthly installations.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2021 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of March 31, 2021**.

Table 15 – Contingency Reconfiguration Costs as of March 31, 2021

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Re	Central	$2,737,167	$12,050,820	$3,007,686	$17,795,674	$24,596,856	72%

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
	Metro	$2,231,431	$10,726,610	$587,396	$13,545,438	$22,390,145	60%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$17,744,042	$24,889,624	71%
	Southern	$2,081,220	$12,405,684	$5,008,143	$19,495,047	$28,712,956	68%
Fuse Savers	Central	$9,970	$789,937	$375,811	$1,175,719	$12,848,369	9%
	Metro	$7,557	$561,915	$216,511	$785,983	$11,800,845	7%
	Palisades	$7,468	$522,454	$133,552	$663,475	$9,164,257	7%
	Southern	$9,792	$859,014	$65,018	$933,824	$14,524,371	6%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$72,139,200**	**$148,927,422**	**48%**

Findings & Observations:

- PSE&G maintained progress during the first quarter of 2021 and stayed on track for the 2021 plan despite some weather impacts and resource constraints experienced in the Metro Division.
- 80 Fuse Saver devices have been installed as part of the pilot program for these devices. PSE&G is monitoring the performance of these initial devices and has already gleaned information that will better inform the planning and execution of the full scope, including specific installation requirements and cost elements, such as additional traffic control required, from the actual installations to date.
- The forecasted completion of the recloser and Fuse Saver scopes of this subprogram saw some adjustment during the first quarter of 2021. For the reclosers, the Central Division recloser scope moving three months out to December 2021 based on additional units added to the scope, while the Palisades Division saw a one-month advancement to November 2021 based on schedule adjustment that reflected increased monthly installations. For the Fuse Savers, each Division saw a slip of six to seven months reflective of the delay to the start of the full scope of this work.
- The Contingency Reconfiguration subprogram forecast decreased from $162.8 million at the end of 2020 to $148.9 million as of the end of the first quarter of 2021. This was largely driven by an approximate $14 million reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967 due to the higher cost per unit observed in the pilot program.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the first quarter of 2021, retrofit installations ramped up with 557 installations completed during the quarter against a target of 565. The first quarter installations were also impacted by weather, particularly during the month of February where only 71 installations took place. However, the performance in January and March allowed PSE&G to nearly reach its first quarter

target. In total, 749 retrofit reclosers have been installed on the Program through the end of the first quarter out of a total program forecast of 2,449 (which is periodically reviewed and updated).

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 16 – Fiber Projects by Division**.

Table 16 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the first quarter of 2021, five additional fiber installation projects (Bergen Point, East Orange, Elizabeth Sub HQ, Metro HQ, and Rahway) and three additional fiber cutover projects (Elizabeth, Spring Valley Road, and Union City) were placed in-service. This brought the total projects in-service as of the end of the first quarter of 2021 to eight for the fiber installation projects and eight for the fiber cutover projects. **Table 17 – Fiber Projects Status as of March 31, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the first quarter of 2021.

Table 17 – Fiber Projects Status as of March 31, 2021

Project Name	Q1 2021 Status
Fiber Installation Projects	
Bergen Point	In-Service (Q1 2021)
Bloomfield	Outside Plant (OP) IFC issued; Construction commenced
Bordentown	Preliminary engineering
Carteret	Preliminary engineering
Central Ave	Preliminary engineering
Central HQ	Preliminary engineering
Chauncey Street	OP construction commenced; First OP fiber run completed; TFI rack delivered
Cranford	In-Service (Q4 2020)
Culver Ave	Preliminary engineering
East Orange	In-Service (Q1 2021)
Edison	Preliminary engineering
Elizabeth Sub HQ	In-Service (Q1 2021)
First Street	OP IFC issued
Fort Lee	OP IFC issued; Construction commenced
Hackensack Sub HQ	In-Service (Q4 2020)
Haddon Heights	Preliminary engineering

Project Name	Q1 2021 Status
Hadley Rd HQ	OP IFC issued; Construction commenced
Haledon	Preliminary engineering
Harrison	OP construction commenced; Commenced battery upgrade installation
Howell Street	Preliminary engineering
Irvington	Preliminary engineering
Irvington Sub HQ	Preliminary engineering
Keasbey	Preliminary engineering
Lehigh Avenue	Preliminary engineering
Mechanic Street	Preliminary engineering
Metro HQ	In-Service (Q1 2021)
Montclair	Preliminary engineering
Morgan Street	Preliminary engineering
Norfolk St	Preliminary engineering
Palisades HQ	Inside Plant (IP)/OP IFC; Construction commenced
Princeton	OP construction commenced
Rahway	In-Service (Q1 2021)
Ridgewood	Preliminary engineering
Roselle	OP construction commenced; Completed both OP fiber runs; completed IP IFC; completed battery upgrade installation
So Orange	Preliminary engineering
Southern HQ	In-Service (Q4 2020)
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	Preliminary engineering
Fiber Cutover Projects	
Delair	In-Service (Q4 2020)
East Riverton	In-Service (Q4 2020)
Elizabeth	In-Service (Q1 2021)
Fairview	Completion dependent upon Fort Lee fiber installation project (tentative start of construction in September 2021)
Henry St	Battery rack installation pending; site visit with Central Division scheduled
Mount Holly	In-Service (Q4 2020)
Polk Street	Completion dependent upon West New York fiber installation project (engineering in progress)
Riverside	In-Service (Q4 2020)
Spring Valley Rd	In-Service (Q1 2021)
Tonnelle Ave	In-Service (Q4 2020)
Union City	In-Service (Q1 2021)
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2021 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2021**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2021

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
Retrofit	Central	$0	$884,278	$1,067,295	$1,951,572	$7,046,140	28%
	Metro	$0	$818,620	$436,089	$1,254,709	$5,958,867	21%
	Palisades	$0	$825,174	$754,869	$1,580,043	$6,507,561	24%

Scope & Division		2019	2020	Q1 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals					
	Southern	$0	$929,058	$956,444	$1,885,502	$7,821,332	24%
Fiber	Central	$1,691	$2,418,851	$796,586	$3,217,128	$7,479,716	43%
Fiber	Metro	$1,457	$1,866,697	$340,713	$2,208,867	$5,857,647	38%
Fiber	Palisades	$1,582	$2,046,762	$248,558	$2,296,902	$4,166,762	55%
Fiber	Southern	$4,731	$910,483	$645,219	$1,560,434	$3,258,924	48%
Fiber	Cutovers*	$0	$876,502	$323,458	$1,199,960	$2,768,762	43%
Wireless Network		$74,306	$6,035,441	$296,946	$6,396,832	$7,737,133	83%
Bulk Purchase**		$0	$1,524,874	$450,013	$1,974,887	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$25,526,835**	**$58,602,845**	**44%**

**-Includes fiber communication cutovers and substation remote terminal unit (RTU) cutovers (the latter of which began having spent in Q1 2021).*
***-The Bulk Purchase account contains expenditures for the bulk purchase of materials in the subprogram. As these materials are used and installed in the field, the Bulk Purchase account is credited with the actual spend then assigned to the appropriate Division, thus at the end of the Program, the balance of this Bulk Purchase account is expected to be $0.*

Findings & Observations:

- During the first quarter of 2021, retrofit installations ramped up as planned with 557 installations completed during the quarter against a target of 565. The first quarter installations were also impacted by weather, particularly during the month of February where only 71 installations took place. However, the performance in January and March allowed PSE&G to nearly reach its first quarter target. In total, 749 retrofit reclosers have been installed on the Program through the end of the first quarter of 2021 out of a total program forecast of 2,449 (which is periodically reviewed and updated).
- Five fiber installation and three fiber cutover projects were placed in-service during the first quarter of 2021, bringing the total number of projects in-service to eight fiber installation projects and eight fiber cutover projects.
- The Grid Modernization – Communication System subprogram forecast remained fairly constant from the end of 2020 to the end of the first quarter of 2021, with an approximate $700,000 decrease to the forecast (or -1%). The cutover forecast increased approximately $1.7 million, which was driven by the substation RTU cutover scope being split off from the retrofit work breakdown structure (which resulted in the retrofit forecast decreasing by a like amount).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the first quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q1 2021 Activities:
  - Conducted Monarch demonstration session.
  - Conducted Advanced Metering Infrastructure (AMI) use case follow-up meeting.

- Completed PSEG application design use case draft document review.
- Completed out feeder and substation device ID in SCADA document.
- Populated DERMS workbook items.
- Discussed DMS data tables in geographic information system (GIS) and their maintenance.

- Forecasted Completion as of the end of the first quarter of 2021: 10/28/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q1 2021 Activities:
  - Finalized outage data warehouse architecture.
  - Interviewed SAP architect for SAP design.
  - Conducted design workshops.
  - Conducted Jira training.
  - Attended product showcases for DMS, OMS, and DERMS.
  - Attended AMI planning meetings.
  - Finalized GIS interface design for customer and premises.
  - Conducted Manager OMS overview workshop.
  - Conducted performance testing meetings with Long Island and Quality Assurance teams.
  - Conducted workshops for data conversion and reporting.
  - Conducted initial AMI/OMS interface meetings.
- Forecasted Completion as of the end of the first quarter of 2021: 5/20/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing distribution supervisory control and data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q1 2021 Activities:
  - Prepared for testing alignment with Quality Assurance team.
- Forecasted Completion as of the end of the first quarter of 2021: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2021 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2021**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			***Forecast***			
$36,213	$16,447,624	$2,488,980	$2,518,103	$2,800,945	$3,428,855	$12,654,786

Actuals to Date	Forecast	% of Actuals to Forecast
$18,972,817	$40,375,507	47%

Findings & Observations:

- Resource constraints remain an area of focus on the subprogram due to the limited number and availability of the specific resources needed to support the subprogram. This has caused some activities to shift, but with no overall impact to the subprogram completion.
- The ADMS forecast remained essentially unchanged at the end of the first quarter of 2021 from the end of 2020 (an increase of $1,368). Likewise, the forecasted completion dates for the primary scopes of DMS/DERMS, OMS, and ADMS Platform remained unchanged from the end of 2020.
- As initially reported in the IM 2020 Third Quarter Report, additional hardware needed for the subprogram resulted in the cost forecast exceeding the Stipulation amount by approximately $5.4 million. While the forecast has remained steady since then, in July 2021, PSE&G made the decision to transfer $7.7 million in funds from the Grid Modernization – Communication System subprogram, which has been consistently under its Stipulation budget by approximately $12 million, driven largely by the savings realized in the wireless communication network scope (also discussed in the IM 2020 Third Quarter Report).

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[3] The outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. These four stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2021**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$599,155	3%	10/12/2022 (↑)
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$1,199,046	6%	11/7/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$896,956	4%	10/6/2022
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,091,303	6%	12/27/2022 (↑)

[3] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* (↑)*-Indicates the forecasted in-service date advanced from the prior quarter.* (↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*							

As shown in **Table 20**, of the four current life cycle station upgrade projects, one had no change in the forecasted in-service date from the end of 2020 to the first quarter of 2021 (Plainfield), while Hamilton's forecasted in-service date advanced twelve days, Woodbury's forecasted in-service date advanced one day, and Paramus's forecasted in-service date slipped 40 days in this period. Given the relatively small magnitude of these changes, the IM has not delved further into the schedule slippage on these projects, but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

1. Hamilton

During the first quarter of 2021, $236,783 was spent on the Hamilton project against a forecast of approximately $196,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $600,000. Notable activities conducted during the first quarter of 2021 included:

- Site plan hearing held/site plan approved;
- SCD permit issued; and,
- Vendor drawings received (final switchgear arrangement).

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$0	$362,372	$236,783	$364,637	$1,541,603	$1,787,646	$10,215,337

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$599,155	$18,200,000	$14,508,379	3%

2. Paramus

During the first quarter of 2021, $358,846 was spent on the Paramus project against a forecast of approximately $371,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $1.2 million. Notable activities conducted during the first quarter of 2021 included:

- Site plan application submitted;
- Soil Conservation District (SCD) permit issued;
- Civil and electrical contingency switchgear drawings IFC; and,
- Vendor drawings received (final switchgear controls).

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals			*Forecast*			
$0	$840,200	$358,846	$3,896,282	$1,125,400	$976,500	$ 10,914,117

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,199,046	$20,200,000	$18,111,345	6%

3. Plainfield

During the first quarter of 2021, $214,632 was spent on the Plainfield project against a forecast of approximately $273,000. This brought total spend through the end of the first quarter of 2021 on the project to approximately $900,000. Notable activities conducted during the first quarter of 2021 included:

- Site plan hearing held/site plan approved; and,
- SCD permit issued.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$0	$682,325	$214,632	$1,058,053	$1,023,860	$1,260,555	$14,562,283

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$896,657	$22,600,000	$18,801,707	4%

4. Woodbury

During the first quarter of 2021, $540,138 was spent on the Woodbury project against a forecast of approximately $595,000. This brought the total spend on the project to approximately $1.09 million. Notable activities conducted during the first quarter of 2021 included:

- License and permitting package issued;
- Civil and electrical drawings IFC; and,
- Site plan hearing held/site plan approved.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$0	$551,165	$540,138	$310,000	$127,913	$725,036	$12,191,648

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,091,303	$18,700,000	$14,445,900	6%

Findings & Observations:

- The primary activities during the first quarter of 2021 continued to center around the life cycle station upgrade projects with the receipt of vendor drawings (switchgear controls/switchgear arrangement) and the advancement of the licensing and permitting design packages. The Hamilton, Plainfield, and Woodbury projects had site plan hearings held, resulting in approval of the site plans, while the Paramus project submitted its site plan application in March 2021.
- With the exception of the Paramus project, there was only minor variations in the life cycle station upgrade project forecasts from the end of 2020 to the end of the first quarter of 2021. On the Paramus project, the forecast increased $1.3 million (or 8%) in this period to $18.1 million, which was primarily the result of the POs switchgear and other miscellaneous equipment coming in higher than initially estimated. Despite this forecast increase, the Paramus project remains forecasted under its current estimate of $20.2 million.
- There was minor movement to the forecasted in-service dates of the four life cycle station upgrade projects, with each forecasted for completion in the fourth quarter of 2022.

F. Gas M&R Station Upgrades

Through the end of the first quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. **Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$1,378,369	5%	Dec 2022 (↑)
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$992,709	3%	Dec 2022 (↑)
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$868,448	5%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$523,484	5%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$699,147	5%	Dec 2023
6. Westampton	Study	$8,300,000	$1,700,000	$10,000,000	$1,519,136	15%	Dec 2021
Subprogram Total		**$91,200,000**	**$18,700,000**	**$109,900,000**	**$5,981,294**	**5%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

During the first quarter of 2021, the Camden Study level estimate was approved by the URB at a total estimate of $29.3 million, while the other projects in the subprogram had their previously approved Study level estimates adjusted with slight reductions in the R&C amounts based on a review of the project risks and the overall subprogram risk profile. The only changes to the forecasted in-service date from the end of 2020 to the end of the first quarter of 2021 were the Camden and Central projects advanced one month from January 2023 to December 2022.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be initial planning efforts, including the prior awarding of bids for the design services on the projects, preparing for issuing the major equipment POs, site surveys, and preparation of permitting packages. Continued engineering and design efforts continue to be a main focus of 2021 first quarter activities.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. The Camden project had its Study level estimate approved by the URB during the first quarter of 2021, which resulted in the estimate increasing by $13.9 million. Also during the first quarter of 2021, the R&C funds on each of the Gas M&R projects were evaluated based on the current risk profiles of the projects and the subprogram, which led to a slight reduction in R&C. The overall subprogram remains in line with the Stipulation budget of $101 million.

1. Camden

Continuing with the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Camden project included:

- Received permit package for review;
- Submitted permit package to permitting agencies; and,
- Circulated scope documents for internal review.

In February 2021, the Camden project had its Study level estimate approved by the URB. This updated estimate increased the base estimate by $14.3 million, while reducing the R&C by $0.4 million, resulting in the total project estimate increasing from $15.4 million to $29.3 million. This increase is the result of higher construction costs stemming from the engineer's 50% estimate ($6.3 million), procurement of material based on received quotes ($6.1 million), and additional project management, licensing and permitting, and engineering support not included in the Office level estimate ($1.9 million). The estimate increase was driven largely by the initial assumption that much of the existing equipment and structures could be reused, which upon further investigation was determined not to be possible and resulted in additional costs for construction and equipment.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$13,326	$859,350	$505,693	$427,753	$3,063,471	$4,145,406	$15,285,001

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,378,369	$29,300,000	$24,300,000	5%

2. Central

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021, notable activities completed on the Central project included:

- Received drawing package for review;

- Submitted permit package to permitting agencies;
- Circulated scope documents for internal review; and,
- Received internal comments for tie-in sequence.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Central project from $6.1 million to $5.1 million, reducing the overall estimate from $30.0 million to $29.0 million.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$6,869	$670,582	$315,258	$158,739	$2,686,668	$7,772,398	$12,289,486

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$992,709	$29,000,000	$23,900,000	3%

3. East Rutherford

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the East Rutherford project included:

- Received preliminary drawing package for review;
- Circulated scope documents for internal review;
- Performed geotechnical fieldwork;
- Received control valve specs for review; and,
- Conducted onsite meeting with Transco to discuss design.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the East Rutherford project from $3.2 million to $2.7 million, reducing the overall estimate from $17.0 million to $16.5 million.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$9,010	$521,865	$337,573	$254,280	$179,734	$1,046,666	$11,450,871

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$868,448	$16,500,000	$13,800,000	5%

4. Mount Laurel

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Mount Laurel project included:

- Received permit package for review;
- Circulated scope documents for internal review.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Mount Laurel project from $2.4 million to $2.0 million, reducing the overall estimate from $11.8 million to $11.4 million.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$5,965	$362,167	$155,351	$247,872	$718,520	$593,333	$7,316,791

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$523,484	$11,400,000	$9,400,000	5%

5. Paramus

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Paramus project included:

- Circulated scope documents for internal review;
- Received noise study results;
- Received control valve specs for review; and,
- Performed geotechnical fieldwork.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Paramus project from $2.7 million to $2.2 million, reducing the overall estimate from $14.2 million to $13.7 million.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals			*Forecast*			
$8,842	$462,452	$227,854	$164,703	$82,327	$89,346	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$699,147	$13,700,000	$11,500,000	5%

6. Westampton

Continuing the preliminary engineering and planning efforts that advanced through 2020, during the first quarter of 2021 notable activities completed on the Westampton project included:

- Circulated scope documents for internal review;
- Burlington soil conservation district approval granted;
- Held virtual pre-bid meeting and onsite review with contractors;
- Received construction bids; and,
- Site plan approval granted by township land development board.

As indicated above, the risk profile to the project and subprogram was reviewed during the first quarter of 2021, which resulted in a slight reduction to the R&C amount of the current estimate for the Westampton project from $2.1 million to $1.7 million, reducing the overall estimate from $10.4 million to $10.0 million.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals			*Forecast*			
$8,395	$1,032,670	$478,072	$2,150,111	$2,974,228	$1,606,645	$49,880

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,519,136	$10,000,000	$8,300,000	15%

IV. Additional Information Following the End of the First Quarter of 2021

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the first quarter of 2021, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the key decisions made on the ES 2 Program, including the related discussion in **Section II.A.**, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2021 First Quarter Report.

A. Decisions Recorded After the First Quarter of 2021

1. Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers

The Stipulation provided the framework for this subprogram, noting: *"PSE&G will invest up to $145 million to harden its electric distribution system and increase system resiliency by implementing contingency reconfiguration strategies, which were also part of the Energy Strong program. These strategies will increase the sections in present loop designs by utilizing reclosers, convert all existing two (2)-section overhead 13kV circuits to three (3)-section circuits by installing additional three (3)-phase reclosers, and install single phase recloser devices on branch lines that operate with only fuses."*

This ROD was issued by PSE&G to document changes in circuits, number of recloser units, and functional recloser types to be included in the Contingency Reconfiguration subprogram.

At the time of the ES 2 filing, PSE&G identified 690 13kV circuits and 500 4kV circuits for inclusion in the ES 2 Contingency Reconfiguration subprogram. As the subprogram progressed through detailed assessment and engineering, each circuit was assessed by PSE&G to determine its current status reflective of updated system plans and changes as well as other work done subsequent to the ES 2 filing, such as Poorest Performing Circuit (PPC) improvements. The results of this review included:

- The identification of 136 initially planned 13kV circuits that were already in three-section loops, which resulted in the removal of 177 13kV reclosers from the subprogram.
- The determination that 102 of the initially planned 4kV circuits were now planned to be upgraded to 13kV within five years based on the need for additional capacity in different areas of the system. This resulted in these circuits, and the related 153 4kV reclosers, being removed from the subprogram as the 4kV reclosers cannot be reused on 13kV circuits and would not be required as system spares.
- The finding that there were additional locations where 13kv branch, feeder, and tie reclosers, and 4kV feeder and tie reclosers could be installed to further isolate the impact of an outage on customers thus improving reliability.

Based on this removal of a set of circuits and reclosers and the identification of opportunities to install devices at other locations, PSE&G considered two alternatives:

1. Sectionalize only the circuits remaining on the filing list after the removal of the 136 13kV circuits and 102 4kV circuits.
2. Conduct a detailed review of 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram utilizing the same cost/benefit process performed for the ES 2 filing in order to improve reliability by reducing the number of customers impacted by an outage.

PSE&G decided to pursue adding additional recloser units to the subprogram utilizing a process consistent with the framework established for the identification and selection of the initial list of circuits included in the subprogram. This will result a cost-effective approach to providing more customers with faster storm restoration and improved reliability.

In reviewing the additional circuits considered for the subprogram, PSE&G's Asset Management reviewed the additional 4kv circuits to determine if they meet the criteria to install reclosers. PSE&G's Engineering group identified three section loop circuits that have a large quantity of customers in a section that could benefit from a feeder recloser. By installing a feeder recloser into a section with a large customer count, PSE&G Operations would be able to restore the customers on one side of the recloser. This will reduce the number of customers impacted by an extended outage. PSE&G's Engineering also identified sections along a circuit that are currently considered part of a mainline section (no sectionalizing device installed) but which can be reconfigured as a branch. By installing a branch recloser to such section, customers on the remainder of the mainline would not be impacted by a fault on the sectionalized length.

As a result of this additional review, PSE&G identified a total of 3654~~2~~ reclosers on 342 circuits to add to the subprogram, comprised of ~~89~~90 4kV reclosers and 275~~253~~ 13kV reclosers. These additional recloser are all currently identified as three-phase recloser, which includes 13 devices that will be part of a pilot program to be installed as a branch (single-phase operable) recloser and 37 that are proposed as tie

reclosers. As noted in the IM 2020 Fourth Quarter Report, there is currently no expected change to the subprogram forecast as a result of these additional reclosers, as they essentially replace the planned reclosers identified for removal from the subprogram.

Findings & Observations

- The IM finds that PSE&G appropriately reviewed the circuits identified at the time of the ES 2 filing to ensure that their current status still warranted the planned upgrades, including removal of circuits that already were sectionalized since the ES 2 filing or are now planned for 13kV upgrades in the next five years.
- The IM finds that the identification of additional circuits for the subprogram, utilizing the same processes used for the ES 2 filing, will benefit PSE&G customers by improving reliability in alignment with the intent of the subprogram.

2. Outage Management System (OMS) Implementation

A major component of the Grid Modernization – Communication System subprogram is the OMS, being planned and developed between PSE&G and the ADMS Vendor, Open Systems International Inc. (OSII). The OMS project operational planning completed in June 2020 confirmed a 24-month implementation schedule that was assumed during contract negotiations. Based on a June 2020 start date, this would lead to the OMS deployment in May 2022. Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. The impacts from Hurricane Isaias resulted in the failure of multiple infrastructure and systems during the PSEG-LI storm response that uncovered gaps in performance testing on the integrated systems. The OMS experienced multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information. Among the lessons learned from this storm were two that specifically impact the OMS implementation:

1. Do not introduce any major system changes immediately before storm season.
2. Ensure enhanced performance testing is conducted for each system and its ecosystem. These tests should be repeated annually, with the proper infrastructure, to ensure reliability and availability of critical systems when they are needed most.

The above lessons learned dictated the following changes to the OMS implementation:

- Shift the deployment date from May 2022 until after the June-September major storm season.
- Increase the services scope for the additional enhanced performance testing expectations.
- Enhance the OMS architecture to ensure separate development/testing environments for the long-term.
- Including contingency to mitigate performance issues in OMS and its ecosystem.

With the above changes identified, PSE&G considered two alternatives:

1. Continue with the original project plan for a May 2022 go-live date with minimal impact to the current OMS cost and schedule.

2. Reschedule the go-live date until after the storm season and use the additional schedule to address revised enhanced system testing requirements and other lessons learned from Hurricane Isaias. This would result in approximately $2.3 million in additional capital costs to support the added scope and extended critical resources.

PSE&G decided to incorporate the recommended lessons learned into the OMS scope as ignoring those lessons learned and accepting the risks associated without complete ecosystem testing requirements coupled with a deployment immediately ahead of the major storm season was not viewed as a viable option for PSE&G. PSE&G has established December 2022 as the new OMS deployment date, which is the first available date after the annual SAP maintenance window closure (typically October-November) and provides PSE&G time to complete enhanced performance testing on the existing systems, which is a critical path dependency for the OMS testing.

The IM has requested additional information on this decisions, which when received and reviewed will provide the IM a basis from which to offer completed findings and observations on this decision.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

JANUARY 20, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 First Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the described delay for the Siemens GIS installation for the Hasbrouck Heights 69kV substation due to Covid-19 related delays has been resolved. If not, please explain.	The Siemens GIS installation at the Hasbrouck Heights 69kV project was completed in May 2021.	No change
RCR-IM-2	Please explain if PSE&G has experienced or anticipates any equipment delivery delays for any of the Energy Strong II subprograms. If so, please explain.	Through the execution of the ES 2 Program (beyond the first quarter of 2021), there have been some instances of material or equipment delays experienced in the Program. During the fourth quarter of 2021, the Contingency Reconfiguration subprogram encountered some delays receiving additional 13kV reclosers, however, between the existing inventory and expediting deliveries, there was no resulting impact to the subprogram. Similarly, in the fourth quarter of 2021, PSE&G was informed by its switchgear vendor that material availability (steel, aluminum, insulation, etc.) caused the upcoming shipment of some of the switchgears to be delayed. Of the affected projects, only the Hamilton substation (a life cycle station upgrade project) had a realized impact of 20 days, which was absorbed by float in the schedule	No change
RCR-IM-3	With reference to pages 2, 3, and 23 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Newark Planning Board rejected the Company's proposed site plan for the Waverly substation due to "aesthetic" reasons.	The IM cannot speak specifically to why the site plan was rejected, but the comments received from the Newark Planning Board included items such as the height of the lightening mast, lack of vegetation, lack of art on fencing/walls, why a green roof was not considered, etc.	No change
RCR-IM-4	Please explain if the revised site plan for the Waverly substation will increase projected costs for the project.	PSE&G's preliminary office level estimate on the changes resulting from the revised site plan indicate an estimated cost increase of $2.6 million. This is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	**Section III.A.15.**
RCR-IM-5	With reference to Table 8 of the Independent Monitor's Draft First Quarter 2021 Report, please confirm that the SAIDI values	SAIDI values by definition are a system-level metric. The SAIDI figures provided in **Section II.D.1.** of this IM report reflect the individual circuit's contribution to the system SAIDI.	No change

ID #	Question/Comment	IM Response	Report Changes
	presented are system-level, not circuit level SAIDI. If not, please explain.		
RCR-IM-6	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the current forecast for Hasbrouck Heights reflects schedule delays for the transmission component of the project.	The current forecast for the Hasbrouck Heights project reflects the current status of the project based on the information known by PSE&G. There was no resulting cost impact due to the delays resulting from the delays experienced on the Hasbrouck Heights 69kV project as it only shifted the start time of construction.	No change
RCR-IM-7	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please indicate if the current forecast for the Market Street substation will remain below the projected costs.	The current forecasts shown in **Table 12** represent PSE&G's forecasts for the Electric Station Flood Mitigation projects as of the end of the current reporting quarter, in other words what PSE&G expects the final costs to be based on what it currently knows. These forecasts are updated monthly by PSE&G reflecting the current information, status, and progress of the projects at the time. For the Market Street project, as of the end of the first quarter of 2021, PSE&G's forecast for the project was approximately $26.2 million. As of the end of the third quarter of 2021, the forecast increased to approximately $29.0 million, which was driven by additional OP overhead and restoration work required based on the complexity of the work and field conditions and higher than estimated traffic control requirements.	No change
RCR-IM-8	With reference to Table 12 of the Independent Monitor's Draft First Quarter 2021 Report, please indicate if the current forecast for the Ridgefield 13kV substation will remain below the projected costs.	For the Ridgefield 13kV project, as of the end of the first quarter of 2021, PSE&G's forecast for the project was approximately $25.3 million. As of the end of the third quarter of 2021, the forecast increased to approximately $26.0 million, which was driven by materials costs and construction/supervision costs. See also the note on the current forecasts provided in response to RCR-IM-7 above.	No change
RCR-IM-9	With reference to page 15 of the Independent Monitor's Draft First Quarter 2021 Report, please explain the difference in function and definition between "major asset" and "capacitor bank" for in-service date.	For the Electric Station Flood Mitigation projects, the final "major asset" is typically the final switchgear or transformer being placed in-service that allows the station to provide electricity to the customers it serves. Other equipment, such as capacitor banks, may be installed after customers are already being served by the new or rebuilt substation.	**Section III.A.**
RCR-IM-10	With reference to page 16 of the Independent Monitor's Draft First Quarter 2021 Report, please explain the root causes for the anticipated delay in the installation of Transformer #3 with regards to the project schedule.	The delay to the Waverly project is not specific to the installation of Transformer #3, it stems from the site plan rejection by the Newark Planning Board during the first quarter of 2021, which required a revised site plan be developed and submitted for approval prior to the project proceeding. The Transformer #3 is	No change

ID #	Question/Comment	IM Response	Report Changes
		the final major asset to be installed on the Waverly project, which is currently forecasted beyond the end date of the ES 2 Program, while other components of the project are expected to still be completed within the Program window.	
RCR-IM-11	With reference to page 17 of the Independent Monitor's Draft First Quarter 2021 Report, please explain how the Clay Street sanitation wall has been determined to be allocated to transmission project.	The rationale for this decision was discussed in the IM 2020 Fourth Quarter Report (Section IV.A.). In summary, PSE&G is executing both a Clay Street ES 2 project and a Clay Street 69kV transmission project. After reviewing the project scopes and intent and purpose of the wastewater wall, PSE&G's capital accounting determination was that the wastewater wall was not required for flood mitigation and instead serves to improve the health, safety, and reliability of the station. As such, this scope of work was transferred to the 69kV project.	No change
RCR-IM-12	With reference to page 20 of the Independent Monitor's Draft First Quarter 2021 Report, please provide an update regarding the change of location for the Orange Valley project.	Three of four properties being acquired under the Orange Heights 69kV Project have been acquired by PSE&G. The fourth property is under contract with a forecasted closing date of March 31, 2022.	No change
RCR-IM-13	With reference to page 21 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Company slowed progress on Ridgefield 4kV for more pressing work on Ridgefield 13kV.	Early in 2021, there were significant weather impacts utilizing the operational resources needed on both the Ridgefield 13kV and Ridgefield 4kV projects. The resources were allocated to the Ridgefield 13kV project to maintain the critical path. The shifting of resources had no impact on the critical path of the Ridgefield 4kV project schedule.	**Section III.A.12.**
RCR-IM-14	With reference to page 22 of the Independent Monitor's Draft First Quarter 2021 Report, please explain why the Toney's Brook project baseline estimate increased by $1.9 million.	The drivers to the $1.9 million increase in the Toney's Brook base estimate include: • Higher concrete quantities ($0.9 million); • Change in T&D surcharge methodology ($0.6 million); and, • Switchgear award higher than estimated ($0.4 million).	No change
RCR-IM-15	With reference to page 25 of the Independent Monitor's Draft First Quarter 2021 Report, please explain if the Company anticipates increased costs as a result of hiring outside contractors due to staffing shortages for recloser installation. If so, please explain. If not, please explain why not.	PSE&G anticipates that the outsourcing of the pole setting for some reclosers in the Metro Division will result in an estimated cost increase of approximately $784,000, which covers the pole setting and preparation work for 197 poles and 136 reclosers. This represents a less than 1% increase in cost per unit for the recloser work. It also benefits the Program by allowing the Metro Division recloser scope to be completed earlier than it otherwise would (avoiding an estimate $100,000 in extended carrying costs and avoiding resource constraints with the overlapping Fuse Saver installations that are commencing in 2022).	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-16	With reference to page 25 of the Independent Monitor's Draft First Quarter 2021 Report, please provide an update on the communications issues associated with the Fuse Savers.	PSE&G has continued bi-weekly meetings with Siemens to resolve the communication issues, which have affected approximately 10% of the devices. The solution to resolve the communication issues involves modifying the external antenna (and modifying the RCU enclosure to accommodate the antenna). PSE&G anticipates the recurring meetings with Siemens will continue early into the full scope Fuse Saver installations to ensure no issues are encountered.	**Section III.B.**
S-INF-1	Please confirm that year-to-year variations in the Program's approved annual budget have not exceeded 10 percent (10%), pursuant to N.J.A.C. 14:3-2A.4(f).	The Stipulation established the ES 2 Program term of October 1, 2019-December 31, 2023. It also established investment levels for the ES 2 Program by subprogram, totaling $691.5 million, and an additional $150.5 million designated for certain capital projects during the ES 2 Program term but to be recovered outside the ES 2 rate mechanism. However, it did not specify an approved annual budget for these investments and as such there is no basis for assessing year-to-year variations.	No change
S-INF-2	**Reference Page 9, Table 7 – Q1 2021 Major Event Performance** Please provide the cumulative SAIFI, CAIDI, and SAIDI of the circuits listed in Table 7 for Q1 2021.	The cumulative SAIDI, CAIDI, and SAIDI from the 2021 Q1 Major Event are as follows, note that like **Table 7** this includes all circuits impacted by the Major Event, including circuits that have not received Energy Strong/ES 2 investments. • CAIDI: 66.63 • SAIFI: 0.04 • SAIDI: 2.85	No change
S-INF-3	**Reference Page 10, Table 8 – Q1 2021 Major Event Additional Information on Selected Circuits** Please reconcile why two (2) circuits (BLO 4016 and FOU 8014) experienced Major Events were no customers were impacted yet an Outage Duration is provided.	The sections of these circuits that are listed in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair). In addition, for the FOU 8014 circuit, the interrupted transformer had no customers assigned to it.	No change
S-INF-4	**Reference Pages 14-15, Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021** a. What is attributed to the forecasted cost of the Hasbrouck Heights substation project increasing from $17,870,384 in the Independent Monitor's Q4 2020 Report to $20,474,628? b. What is attributed to the forecasted cost of the Leonia substation project decreasing from $30,396,846 in the	Regarding the forecast change from the fourth quarter of 2020 to the first quarter of 2021 on these electric substations: a. The Hasbrouck Heights forecast increased approximately $2.6 million, which was primarily driven by the civil construction bid coming in higher than estimated ($1.2 million) and a higher dewatering estimate reflective of site conditions ($1.3 million).	**Section III.A.4. & Section III.A.7.**

ID #	Question/Comment	IM Response	Report Changes
	Independent Monitor's Q4 2020 Report to $25,082,905?	b. The Leonia forecast decreased by approximately $5.3 million, which was driven by civil and electrical construction awards coming in lower than estimated.	
S-INF-5	**Reference Page 15, Electric Station Flood Mitigation Subprogram** Refer to the statement "Two other projects had forecasted in-service movements greater than 60 days, including Hasbrouck Heights, which improved 64 days based on PS&EG identifying the in-service date as the final major asset instead of the previously identified date of when the capacitor banks were completed…" Please discuss if this treatment is consistent with the in-service dates of the other Electric Station Flood Mitigation projects.	For the Electric Station Flood Mitigation projects, the final "major asset" is typically the final switchgear or transformer being placed in-service that allows the station to provide electricity to the customers it serves. Other equipment, such as capacitor banks, may be installed after customers are already being served by the new or rebuilt substation.	**Section III.A.**
S-INF-6	**Reference Page 20, Orange Valley Substation Project** Regarding the statement "The variance in first quarter spend was largely the result of the project re-allocating an engineering invoice between this ES 2 project and the 69kV project…" Please provide additional details about the Company's decision to re-allocate an engineering invoice to the 69kV project, including the re-allocated costs.	The engineering invoice reallocation was forecasted in error to the Orange Valley ES 2 project, rather than the Orange Valley 69kV project. This reallocation reflects the cost of this engineering work ($35K) being removed from the Orange Valley ES 2 forecast and incorporated into the Orange Valley 69kV forecast.	**Section III.A.10.**
S-INF-7	**Reference Page 22, Toney's Brook Substation Project** Regarding the increase to the base estimate of the Toney's Brook substation project, please provide additional details about the modification titled "Changing in T&D surcharge methodology ($0.6 million)."	The change in T&D surcharge methodology caused an increase in Outside Service Electrical construction planned surcharge rate which increased by over 45% from 2019 to 2020. As a result, approximately $587,000 of the $0.6 million increase on Toney's Brook Conceptual level estimate was attributed to increase in electrical construction. The remainder of the $0.6 million increase is associated with Project Management labor.	**Section III.A.14.**
S-INF-8	**Reference Page 25, Contingency Reconfiguration Subprogram** Refer to the statement "While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the remote control unit (RCU), where in the supervisory control and data acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders." Please indicate if the Company has any plans	The communication issues experienced on the Fuse Savers have only affected approximately 10% of the installed devices. Any device that demonstrates communication issues will be addressed via the solution developed by PSE&G and Siemens. See also the related discussion in response to RCR-IM-16.	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
	to address the communications issues on the 80 Fuse Saver devices that were already installed.		
S-INF-9	**Reference Page 26, Contingency Reconfiguration Subprogram** Regarding the "approximate $14 million reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967", please discuss the factors considered by the Company in selecting the Fuse Savers that were removed from the Program.	PSE&G has informed the IM that at this time, a decision has not been made on which specific Fuse Savers are to be removed from the program. The increased average cost per unit has resulted in a reduction of the quantity of Fuse Savers that can fit within the program budget. The primary factor that will be used to determine which Fuse Savers to remove from the Program is the cost benefit ratio, consistent with the original prioritization approach.	No change
S-INF-10	**Reference Page 35-36, Camden M&R Station Project** Regarding the statement "This updated estimate increased the base estimate by $14.3 million, while reducing the R&C by $0.4 million, resulting in the total project estimate increasing from $15.4 million to $29.3 million. This increase is the result of higher construction costs stemming from the engineer's 50% estimate ($6.3 million), procurement of material based on received quotes ($6.1 million), and additional project management, licensing and permitting, and engineering support not included in the Office level estimate ($1.9 million)." a. Please provide the originally budgeted costs for construction (from the engineer's 50% estimate) and for procurement of material based on received quotes. b. Please describe any specific factors that led to the higher costs for construction and material procurement.	Regarding the Camden M&R project: a. The originally budgeted costs were $4.7 million for construction and $4.3 million for procurement of material. b. The original estimate was based on reusing much of the existing Liquid Propane Air (LPA) equipment and raising the existing LPA building. Due to a remediation project at the site, the existing building will need to be demolished and relocated. This change resulted in additional construction costs for foundations that will be needed to achieve the FEMA +1' elevation and additional demolition costs. Similarly, two existing 1200 HP air compressors, switchgear, and auxiliary equipment were determined to not be suitable for reuse. Additionally, new LPA mixing control capabilities requires additional control valves and automation.	**Section III.F.1.**
S-INF-11	**Reference Pages 39-40, Decisions Recorded After the First Quarter of 2021, Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers** Refer to the statement "As a result of this additional review, PSE&G identified a total of 342 reclosers to add to the subprogram, comprised of 89 4kV reclosers and 253 13kV reclosers." a. Please provide the total number of 4kV and 13kV circuits associated with this work, including a breakdown of the total number of sections currently within these circuits.	Regarding the additional reclosers identified for the Contingency Reconfiguration subprogram: a. Of the additional recloser identified, now updated to 365 units, there are 961 sections. This includes 90 4kV reclosers on 57 circuits and 275 13kV recloser on 206 circuits. b. Of the 365 additional reclosers, all are currently identified as three-phase reclosers. This includes 13 reclosers that will be part of a pilot program to be installed as a branch (single-phase operable) recloser. c. Of the 365 additional recloser, 37 are proposed as tie reclosers.	**Section IV.A.1.**

ID #	Question/Comment	IM Response	Report Changes
	b. Of the 342 additional reclosers, please provide a breakdown of three-phase reclosers versus single-phase reclosers. c. Please indicate how many of the additional reclosers will be used to create new tie points between circuits. d. Please indicate if the Company considered historical reliability when selecting the circuits that would received these additional reclosers.	d. PSE&G's selection of these additional circuits was consistent with the cost-benefit process utilized for the selection of the initial circuits for the subprogram, which included an assessment of historical performance and number of customers served.	
S-INF-12	**Reference Pages 40-41, Decisions Recorded After the First Quarter of 2021, Energy Strong II Electric Program – Outage Management System (OMS) Implementation** Refer to the statement "Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. Among the lessons learned from this storm were two that specifically impact the OMS implementation." Please provide additional details about the OMS issues experienced during Hurricane Isaias.	The impacts from Hurricane Isaias resulted in the failure of multiple infrastructure and systems during the PSEG-LI storm response that uncovered gaps in performance testing on the integrated systems. The OMS experienced multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information.	**Section IV.A.2.**
Rate Counsel 12/20/2021 Letter to the IM	At the end of the first quarter 2021, the Energy Strong II ("ESII") program remains in the early stages. The Independent Monitor reports that spending for the quarter ending March 31, 2021 has been $40,652,703 or 5.2 percent of the current forecast of $770,614,891 program (including the $100 million for Electric Stipulated Base and excluding $78.5 million of risk and contingency). Rate Counsel notes that the parties stipulated to $842 million to complete the ES II Program with $641 million for electric, $50.5 million for gas, and $150.5 million within Stipulated Base for electric and gas spending.	The IM provides additional clarification that the $770,614,891 ES 2 Program forecast as of the end of the first quarter of 2021 includes both the $100 million in Electric Stipulated Base and the $50.5 million in Gas Stipulated Base.	No change
Rate Counsel 12/20/2021 Letter to the IM	Rate Counsel also notes that the budget for Electric stipulated base has been set to $100 million for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the four substations (Hamilton, Paramus, Plainfield, and Woodbury). The current Study level estimates for the program are $79,700,000 including $16,600,000 for risk and contingency.	The IM provides additional clarification that the Electric Stipulated Base budget of $100 million established by the Stipulation includes investments in electric station life cycle projects and electric outside plant higher design and construction standards projects. The estimates detailed in this IM report for the noted substations reflect the currently approved projects in this subprogram.	No change

ID #	Question/Comment	IM Response	Report Changes
Rate Counsel 12/20/2021 Letter to the IM	The current forecast for the Electric Flood mitigation program decreased from $339,403,267 in the Fourth Quarter Report to $331,374,281 in the First Quarter Report, not including risk and contingency estimates. Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2021, states that the spending amount for the subprogram is $318,900,000 in budgeted base project costs and $59,800,000 allocated to risk and contingency. The Independent Monitor notes two formal Records of Decision ("ROD") were issued during the first quarter of 2021. These two RODs included 13kV and 4kV reclosers related to the Contingency Reconfiguration program (ESII-CR-1); and outage management system ("OMS") implementation (ESII-GM-5).	The IM provides additional clarification that the $318.9 million base estimate total and $59.8 million R&C total are reflective of the current project estimates, which are at different estimate phases depending on how advanced the individual project is. The current forecast as of the end of the first quarter of 2021 for the Electric Station Flood Mitigation subprogram is $331.4 million. Additionally, the two RODs discussed in this IM report were issued during the second quarter of 2021, not the first quarter.	No change
Rate Counsel 12/20/2021 Letter to the IM	The First Quarter Report notes that two substations have forecasted in-service dates that have moved more than 60 days. These two substations are Hasbrouck Heights and Waverly. According to Pegasus, "the Hasbrouck Heights forecasted in-service date previously moved in the fourth quarter of 2020 from early December 2022 to mid-April 2023 due to Covid-19 related delays on the Siemens GIS installation on the associated Hasbrouck Heights 69kV project, which has resulted in the Hasbrouck Heights ES 2 project delaying the start of construction from July 2021 to January 2022. The fourth quarter in-service date was based on the capacitor bank in-service date (April 2023), which has now been updated by PSE&G to reflect the switchgear in-service date currently forecasted for February 2023." For Waverly, Pegasus notes, "the Waverly in-service date slipped 314 days from the forecasted in-service date at the end of the prior quarter. This was due to PSE&G being denied approval of the site plan by the Newark Planning Board, which requires PSE&G to address the comments received, coordinate community meetings on the new site plan application, and re-submit to the Newark Planning Board."	The IM confirms this information as accurate.	No change
Rate Counsel 12/20/2021 Letter to the IM	The First Quarter Report noted that the Contingency Reconfiguration subprogram total forecast decreased from $162,806,273 in the Fourth Quarter report to $148,927,422. The stipulated budget for the subprogram is $145 million. Pegasus observed that the decrease in the program costs was attributed to	The IM confirms this information as accurate.	No change

ID #	Question/Comment	IM Response	Report Changes
	the “reduction to the Fuse Saver scope due to the number of units planned for the Program decreasing from 2,572 to 1,967 due to the higher cost per unit observed in the pilot program.”		

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2021 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

MAY 5, 2022

Table of Contents

I. Executive Summary 1
II. Program Status 4
A. Key Decisions 4
B. Program Management 6
C. Cost Assignments 7
D. System Performance 11
III. Project Status 12
A. Electric Station Flood Mitigation 12
B. Contingency Reconfiguration 26
C. Grid Modernization – Communication System 29
D. Grid Modernization – ADMS 33
E. Electric Stipulated Base 34
F. Gas M&R Station Upgrades 38
IV. Additional Information Following the End of the Second Quarter of 2021 42
A. Market Street In-Service Date 42
B. Updated Fiber Projects 42

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems	ADMS
Allowance for Funds Used During Construction	AFUDC
Architectural and Engineering	A/E
Board of Public Utilities	BPU
Construction Work In Progress	CWIP
Costs of Removal	COR
Distribution Management System	DMS
Distributed Energy Resource Management System	DERMS
Distribution Supervisory Control and Data Acquisition	DSCADA
Energy Strong 2	ES 2
Flood Hazard Area	FHA
Gas Metering & Regulating	Gas M&R
Independent Monitor	IM
Inside Plant	IP
Issued for Bidders	IFB
Issued for Construction	IFC
Issued for Review	IFR
New Jersey Department of Environmental Protection	NJDEP
Open Systems International Inc.	OSII
Outage Management System	OMS
Outside Plant	OP
Poorest Performing Circuit	PPC
Public Service Electric & Gas	PSE&G
Purchase Orders	POs
Record of Decision	ROD
Remote Control Unit	RCU
Remote Terminal Unit	RTU

Risk and Contingency ..... R&C

Transmission & Distribution ..... T&D

Transmission Fiber Infrastructure ..... TFI

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant (OP) design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram).

During the second quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed one additional fiber installation project in-service, and continued the retrofit recloser installations, with 685 units installed during the second quarter of 2021, bringing the total number of retrofit reclosers installed to 1,432 units out of a current forecast of 2,449 units. The Grid Modernization – ADMS subprogram continued to formalize system requirements and prepared for factory acceptance testing on the platform. While the Gas M&R subprogram kicked off the Westampton project, while other stations continued to advance design, prepared construction bids, and continued other preliminary activities. An additional project (State Street – OP) was added to the life cycle upgrades portion of the Electric Stipulated Base, while the four previously approved projects continued to advance their design efforts, with the Paramus project having its site plan approved in June 2021 and commencing construction for the contingency switchgear. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2021

Subprogram	Q2 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount
Electric Station Flood Mitigation	$20,807,542	$90,603,138	$346,463,155	26%	Dec 2024	$389M
Contingency Reconfiguration	$13,419,784	$85,558,983	$147,070,235	58%	Dec 2023	$145M
Grid Modernization – Communications	$7,862,176	$33,389,013	$60,377,806	55%	Dec 2023	$72M
Grid Modernization – ADMS	$2,168,187	$21,141,005	$42,712,616	49%	Dec 2022	$35M
Electric Stipulated Base	$5,319,246	$9,105,707	$100,000,000	9%	Dec 2023	$100M
Gas M&R Station Upgrades^	$4,237,932	$10,219,223	$92,000,002	11%	Dec 2023	$101M
Total*	$53,814,867	$250,150,685	$788,758,650	32%	Dec 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown. The Electric Station Flood Mitigation total spend and total forecast also does not include $133,616 previously spent on the Constable Hook project that is being removed from the ES 2 Program.*

***-Final in-service date.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

During the second quarter of 2021, PSE&G submitted updated estimates to its Utility Review Board (URB) for the two Grid Modernization subprograms (including separate estimates for the wireless network/retrofits scope and fiber installation/cutover scope of the Grid Modernization – Communication Network subprogram). The original and current estimates for these Grid Modernization components are provided in **Table 2 – Grid Modernization Subprograms Updated Estimates as of June 30, 2021**. As shown in **Table 2**, while the ADMS and fiber installation/cutover scopes saw increases to their estimates, there was no net change to the Grid Modernization initiatives as the wireless network/retrofits scope saw a corresponding reduction. These updated estimates are discussed in more detail within **Section III.C.** and **Section III.D.** of this report.

Table 2 – Grid Modernization Subprograms Updated Estimates as of June 30, 2021

Subprogram/Scope	Current Estimate Level	Filing Estimate	Current Estimate	Variance
ADMS	Conceptual	$35,000,000	$42,700,000	+$7,700,000
Grid Modernization – ADMS Subtotal	***Conceptual***	***$35,000,000***	***$42,700,000***	***+$7,700,000***
Wireless Network & Retrofits	Conceptual	$48,600,000	$35,100,000	($13,500,000)
Fiber	Study	$23,400,000	$27,500,000	+$4,100,000
Grid Modernization – Communication System Subtotal	***Conceptual / Study***	***$72,000,000***	***$62,600,000***	***($9,500,000)***
Grid Modernization Placeholder	-	-	***$1,700,000***	***+$1,700,000***
Total		**$107,000,000**	**$107,000,000**	**$0**

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 3 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2021**.

Table 3 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$5,159,731	49%	10/25/2021
2. Clay Street	$33,800,000	$2,156,501	6%	12/19/2022 (↑)
3. Front Street^	$27,400,000	$190,915	1%	11/2/2023
4. Hasbrouck Heights	$22,700,000	$2,020,326	9%	2/7/2023
5. Kingsland	$8,300,000	$381,286	5%	10/4/2023
6. Lakeside Avenue	$47,900,000	$956,178	2%	12/13/2023
7. Leonia	$27,500,000	$13,034,343	47%	9/30/2022
8. Market Street	$26,900,000	$23,514,129	87%	9/23/2021^^
9. Meadow Road	$9,000,000	$786,103	9%	9/22/2023 (↓)
10. Orange Valley	$20,200,000	$594,041	3%	12/29/2023 (↓)
11. Ridgefield 13kV	$27,600,000	$13,319,925	48%	11/8/2022 (↓)
12. Ridgefield 4kV	$19,500,000	$18,777,287	96%	**5/16/2021** (↑)
13. State Street	$22,400,000	$1,193,633	5%	9/23/2022
14. Toney's Brook	$18,800,000	$963,752	5%	4/21/2023

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
15. Waverly	$35,400,000	$6,062,028	17%	12/18/2024 (↓)
16. Woodlynne	$19,400,000	$1,519,097	8%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

^^*-See* ***Section IV.A.*** *for additional information on the Market Street in-service date following the end of the second quarter of 2021.*

As indicated in **Table 2**, the projects that have previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest spend. Additionally, five of the stations (Clay Street, Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street) had new estimates approved by the URB in during the second quarter of 2021, while the Front Street project was also approved by the URB to replace the cancelled Constable Hook project. **Table 2** also shows that six of the sixteen projects had movement during the second quarter of 2021 in the forecasted in-service date, with two advancing and four slipping. Of these six projects, four of the projects (Market Street, Ridgefield 4kV, Ridgefield 13kV, and Orange Valley) had forecasted in-service dates change by less than two weeks, with the Ridgefield 4kV project achieving its in-service status on May 16, 2021. The Clay Street forecasted in-service date advanced 50 days from the status as of the end of the first quarter of 2021. Only one project (Waverly) had movement more than 60 days, which is the threshold the Independent Monitor (IM) applied during the original Energy Strong Program for evaluating changes to the project schedules. The Waverly in-service date slipped an additional 92 days from the forecasted in-service date at the end of the prior quarter, which continues to reflect the impacts of the project's site plan denial in March 2021. The project team continues to work on a new site plan application, which once approved will provide PSE&G with a clearer view of the Waverly schedule, including potential opportunities to advance the in-service date.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to ensure the ES 2 Program is completed within the defined timeline.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On March 18, 2022, a draft report was presented and submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this

IM 2021 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Second Quarter Report are presented below in **Table 4 – ES 2 Records of Decisions**.

Table 4 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and **Section II.A.1.** in this report)*

Subprogram	Record of Decision	IM Comments
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and* ***Section II.A.2.*** *in this report)*

During the second quarter of 2021, two key decisions were issued by PSE&G, each of which was initially discussed in the IM 2021 First Quarter Report and summarized below.

1. Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers

This ROD was issued by PSE&G to document changes in circuits, number of recloser units, and functional recloser types to be included in the Contingency Reconfiguration subprogram.

At the time of the ES 2 filing, PSE&G identified 690 13kV circuits and 500 4kV circuits for inclusion in the ES 2 Contingency Reconfiguration subprogram. As the subprogram progressed through detailed assessment and engineering, each circuit was assessed by PSE&G to determine its current status reflective of updated system plans and changes as well as other work done subsequent to the ES 2 filing, such as Poorest Performing Circuit (PPC) improvements and other reliability enhancements outside of the ES 2 Program. Based on the results of this review, 238 circuits were identified for removal from the subprogram, comprising of 177 of the initially planned 13kV reclosers and 153 of the initially planned 4kV reclosers, which included 54 circuits that were part of the PPC improvements and 78 other circuits that received reliability enhancements. The removal of these circuits presented PSE&G with the opportunity to conduct a detailed review of its 4kV and 13kV circuits to identify cost effective opportunities to include additional circuits in the subprogram following the same cost/benefit process utilized for the ES 2 filing.

As a result of this additional review, PSE&G identified a total of 342 reclosers to add to the subprogram, comprised of 89 4kV reclosers and 253 13kV reclosers. As noted in the IM 2020 Fourth Quarter Report, there is currently no expected change to the subprogram forecast as a result of these additional reclosers, as they essentially replace the planned reclosers identified for removal from the subprogram.

Findings & Observations

- The IM finds that PSE&G appropriately reviewed the circuits identified at the time of the ES 2 filing to ensure that their current status still warranted the planned upgrades, including removal of circuits that already were sectionalized since the ES 2 filing or are now planned for 13kV upgrades in the next five years.
- The IM finds that the identification of additional circuits for the subprogram, utilizing the same processes used for the ES 2 filing, will benefit PSE&G customers by improving reliability in alignment with the intent of the subprogram.

2. Outage Management System (OMS) Implementation

A major component of the Grid Modernization – Communication System subprogram is the OMS, being planned and developed between PSE&G and the ADMS Vendor, Open Systems International Inc. (OSII). The OMS project operational planning completed in June 2020 confirmed a 24-month implementation schedule that was assumed during contract negotiations. Based on a June 2020 start date, this would lead to the OMS deployment in May 2022.

Immediately following the completion of the operational planning, Hurricane Isaias impacted the eastern seaboard, resulting in widespread power outages and exposing system reliability and availability inefficiencies. These impacts were unique from prior Major Events in that the failure of multiple infrastructure and systems during the Hurricane Isaias response uncovered gaps in performance testing on the integrated systems. Lessons learned from this storm included avoiding introducing any major system changes immediately before storm season and ensuring enhanced performance testing is conducted for each system and its ecosystem.

PSE&G opted to incorporate the recommended lessons learned into the OMS scope as ignoring those lessons learned and accepting the risks associated without complete ecosystem testing requirements coupled with a deployment immediately ahead of the major storm season was not viewed as a viable option for PSE&G. PSE&G has established December 2022 as the new OMS deployment date, which is the first available date after the annual SAP maintenance window closure (typically October-November) and provides PSE&G time to complete enhanced performance testing on the existing systems, which is a critical path dependency for the OMS testing. PSE&G anticipates that the additional scope and extension of critical resources based on the revised deployment date will result in approximately $2.3 million in additional costs to the subprogram. These additional costs are comprised of the following components:

- Extend OSI services contract: $1.5 million
- Extend Cognizant services contract: $0.2 million
- Extend Pontoon services contract: $0.2 million
- Extend internal subject matter experts: $0.2 million
- Development Environment: $0.2 million
- Development Contingency: $0.3 million
- Reduced travel and expenses: ($0.3 million)
  Total: $2.3 million

Findings & Observations

- While this decision results in a higher cost for the subprogram, the alternative of maintaining the original scope and planned May 2022 go-live date exposes PSE&G to risks associated with introducing a new system immediately before storm season and having less robust performance testing.
- The IM finds it appropriate for PSE&G to incorporate the lessons learned from Hurricane Isaias into the scope and planning for the OMS implementation.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with ES 1, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 5 – ES 2 Program Costs of Removal as of June 30, 2021, below itemizes the charges to COR for the second and first quarters of 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through June 30, 2021.

Table 5 – ES 2 Program Costs of Removal as of June 30, 2021

Subprogram	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)					
Electric Station Flood Mitigation	**$1,141.0**	**$1,129.5**	**$2,270.5**	**$1,021.1**	**$0**	**$3,291.6**
Contingency Reconfiguration	**$485.2**	**$622.9**	**$1,108.1**	**$2,198.9**	**$431.0**	**$3,738.0**
Grid Modernization – Communications	**$37.9**	**$37.8**	**$75.7**	**$24.4**	**$0**	**$100.1**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Gas M&R Station Upgrades	**$87.6**	**$0**	**$87.6**	**$0**	**$0**	**$87.6**
Gas Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$1,751.7**	**$1,790.2**	**$3,541.9**	**$3,244.4**	**$431.0**	**$7,217.3**

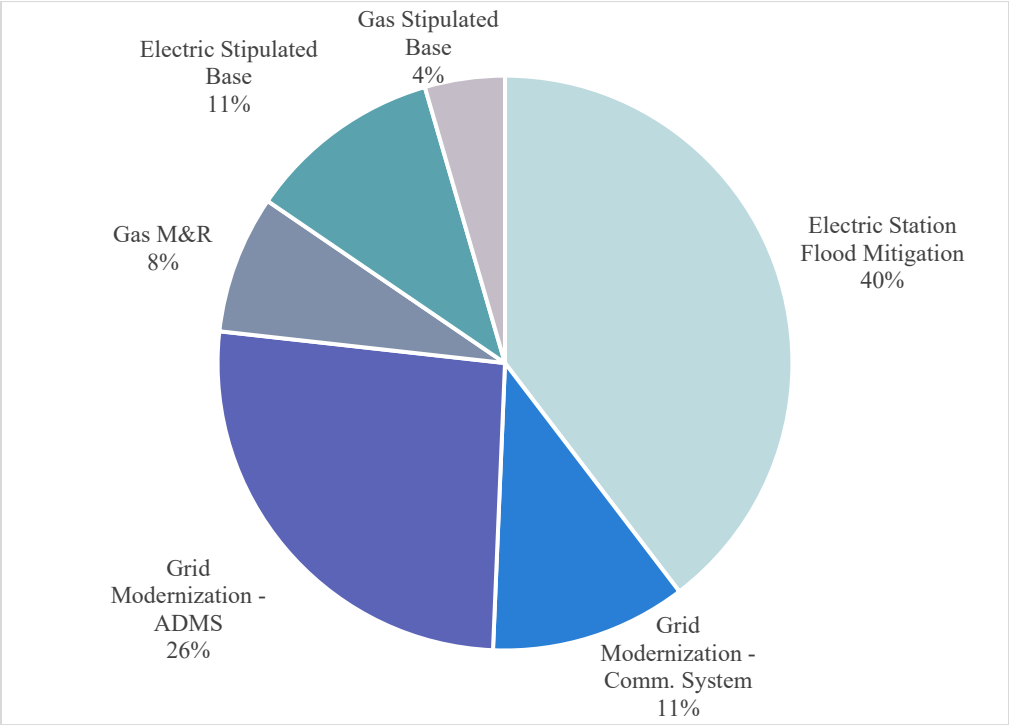
The reduction in Contingency Reconfiguration COR for the second quarter of 2021 from the first quarter is primarily attributable to fewer recloser removal jobs during the second quarter. COR charges for the Gas M&R subprogram during the second quarter of 2021 reflect the demolition of existing on-site buildings at the Westhampton project.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

As of June 30, 2021, the ES 2 Program CWIP balance was $84.6 million, compared to $67.0 million as of March 31, 2021. The largest components of as of the end of the second quarter of 2021 were the Waverly ($6.2 million), Leonia ($5.6 million), and Academy Street ($5.4 million) substations, as well as the Paramus substation Electric Stipulated Base lifecycle project ($5.4 million), and work associated with ADMS ($22.1 million). The Electric Station Flood Mitigation subprogram comprises the largest

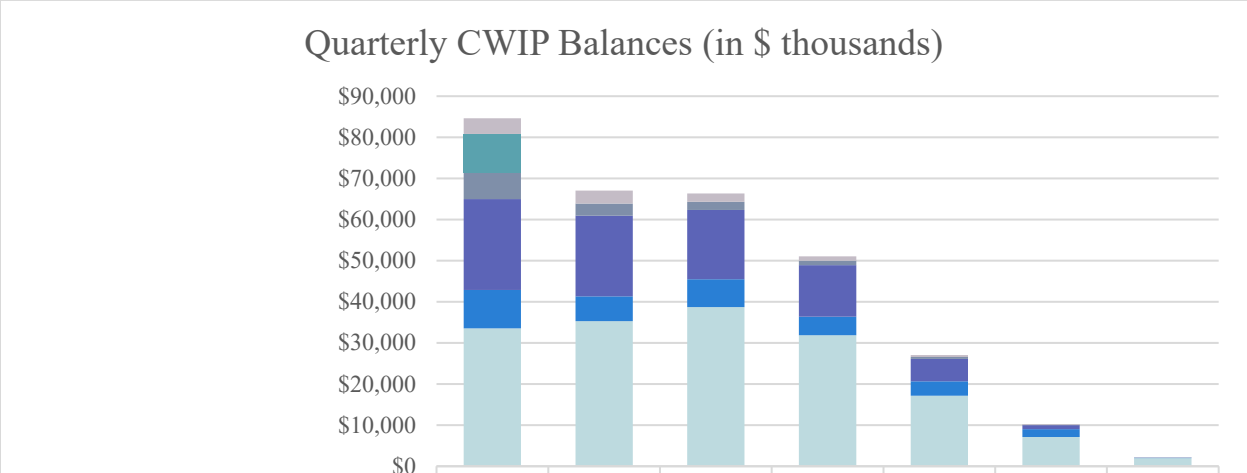
component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2021** below.

Figure 1 – ES 2 CWIP as of June 30, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second and first quarters of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2021



	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$3,808	$3,143	$2,057	$1,031	$449	$160	$29
Electric Stipulated Base	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$6,574	$2,981	$1,975	$1,118	$502	$131	$23
Grid Modernization - ADMS	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. System	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in-service totaled $17.2 million during the second quarter of 2021, mainly comprised of $11.1 million of assets at the Ridgefield substation. Total ES 2 Program transfers from CWIP have been $34.6 million through June 30, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no Allowance for Funds Used During Construction (AFUDC) is recorded on these expenditures. This accounting treatment is fully in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the second and first quarters of 2021, total AFUDC for the years 2020 and 2019, and total ES 2 Program AFUDC accrued to date, is shown below in **Table 6 – ES 2 Program AFUDC as of June 30, 2021**.

Table 6 – ES 2 Program AFUDC as of June 30, 2021

Subprogram	Q2 2021	Q1 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Electric Station Flood Mitigation	**$576.7**	**$558.6**	**$936.5**	**$9.9**	**$2,081.7**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$95.5**	**$59.0**	**$184.3**	**$0.2**	**$339.0**
Grid Modernization – ADMS	**$316.9**	**$274.2**	**$352.7**	**$0.1**	**$943.9**
Electric Stipulated Base	**$80.5**	**$49.6**	**$44.0**	**$0**	**$174.1**

Subprogram	Q2 2021	Q1 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)				
Gas M&R Station Upgrades (incl. Stip. Base)	**$107.6**	**$72.2**	**$70.0**	**$0.2**	**$250.0**
Total	**$1,177.2**	**$1,013.6**	**$1,587.5**	**$10.4**	**$3,788.7**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2021, based on data as of June 30, 2021, the recalculated weighted average AFUDC accrual rate (6.83%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the second quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for ES 2 projects during the second quarter of 2021 increased over AFUDC accrued during the first quarter of 2021 as the result of increases in total average CWIP balances for almost all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2021 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 Program AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For the ES 2 Program electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and

other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 7 – ES 2 Program Overhead Allocations as of June 30, 2021** are the allocated overhead costs charged to ES 2 projects for the first and second quarters of 2021, the total 2021 year-to-date, total 2020, total 2019 (the fourth quarter of 2019), and total ES 2 Program allocated overheads to date.

Table 7 – ES 2 Program Overhead Allocations as of June 30, 2021

Subprogram	Q2 2021	Q1 2021	2021 Year-to-Date	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
		(in $ thousands)				
Electric Station Flood Mitigation	$4,352	$5,588	$9,940	$14,023	$287	$24,250
Contingency Reconfiguration	$4,006	$4,215	$8,221	$17,109	$3,415	$28,745
Grid Modernization – Communications	$2,506	$1,743	$4,249	$3,625	$12	$7,886
Grid Modernization – ADMS	$124	$119	$243	$426	$11	$680
Electric Stipulated Base	$287	$126	$413	$259	$0	$672
Gas M&R Station Upgrades (incl. Stip. Base)	$119	$131	$250	$291	$15	$556
*Total**	$11,393	$11,922	$23,316	$35,733	$3,740	$62,788

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The changes in overhead costs for the second quarter 2021 from the first quarter of 2021 largely reflect more bargaining unit grid modernization labor in the second quarter, and the periodic fluctuations in certain costs, such as outside services, which receive no overhead surcharges.

As noted in the IM's Report for the First Quarter of 2021, the Company revised its overhead surcharging methodology in the first quarter of 2020 by, among other things, consolidating the number of overhead surcharge cost pools from 38 cost pools based on geographic/organizational bases to three statewide/functional cost pools and one materials handling pool. This change resulted in one-time charges to several ES 2 projects recorded only for that quarter, and which were included in the figures provided in the IM's report. The IM believes the amounts allocated to ES 2 projects reflect application of the same surcharge methodology as amounts charged for non-ES 2 projects.

D. System Performance

1. Current Reporting Quarter Major Events

During the second quarter of 2021, there was one Major Event reported in PSE&G's service territory concerning a load shedding event at the Montclair Substation. As this Major Event was non-weather

related and did not involve ES 2 investments there is no additional information for the IM to report on this Major Event.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the second quarter of 2021 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2021**.

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
	Jun. 2021		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
	Jun. 2021			KO							C				IS					CO (Q2)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Jun. 2021								KO				C						IS	CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Jun. 2021		KO									C				IS				CO (Q1)
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Jun. 2021			KO											C				IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Jun. 2021						KO							C					IS	CO (Q4)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Jun. 2021			KO		C								IS			CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Jun. 2021			KO					C/OS				CO							

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Jun. 2021			KO											C			IS		CO (Q2)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Jun. 2021					KO										C			IS	CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Jun. 2021			KO	C										IS			CO		
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Jun. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Jun. 2021		KO						C					IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Jun. 2021			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Jun. 2021			KO			C													IS (Q4); CO (Q2 2025)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Jun. 2021		KO												C				IS	CO (Q2)

Dec. 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the second quarter of 2021 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne

Activity	Total # of Projects	Specific Projects
Key Drawing Review	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	15	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	16*	Academy Street; Clay Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
A/E Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	6	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; Waverly
In-Service	2^	Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 16 switchgears at 13 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or OP construction.*
^-The Ridgefield 4kV and Market Street projects completed their 4kV to 13kV conversions, while the Market Street project has a final in-service activity associated with the 26kV reconfiguration that is forecasted for September 2021.

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2021** summarizes the planned activities for each project during the third quarter of 2021, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2021

Station	Upcoming Activities for Q3 2021	Carryover Activities from Q2 2021
1. Academy Street	• Continued engineering and construction	• Continued engineering and construction
2. Clay Street	• Continued engineering	• Continued engineering
3. Constable Hook	*Removed from the ES 2 Program*	
4. Hasbrouck Heights	• Contingency plan control drawings issued for construction (IFC)	• Continued engineering
5. Kingsland	• Commence license and permitting design	• Continued engineering
6. Lakeside Avenue	• Submit site plan application • Vendor drawings received (final switchgear arrangement)	• Continued engineering
7. Leonia	• Continued engineering and construction • Start commissioning of 13kV switchgear #1	• Continued engineering and construction
8. Market Street	• Final in-service date (26kV reconfiguration) • Start civil and electrical demolition	• Continued construction
9. Meadow Road	• Continued engineering	• Continued engineering
10. Orange Valley	• Continued engineering	• Continued engineering

Station	Upcoming Activities for Q3 2021	Carryover Activities from Q2 2021
11. Ridgefield 13kV	• Phase 1 electrical construction start • Phase 1 civil construction complete • Phase 2 electrical construction PO issued	• Continued engineering and construction
12. Ridgefield 4kV	• Completed electrical construction (OP) • Start civil and electrical demolition	• Start electrical demolition
13. State Street	• 70% estimate completed • Switchgear delivered	• 70% estimate completed • Continued engineering and construction
14. Toney's Brook	• Major licenses and permits issued	• Continued engineering
15. Waverly	• Updated license and permitting package for site plan; special hearing requested • Continued engineering	• Continued engineering
16. Woodlynne	• 70% estimated completed	• 70% estimate completed • Continued engineering
17. Front Street	• Switchgear PO issued • Permit compliance matrix completed • Scope document approved	• None

The current project estimates, including base and R&C amounts, is shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2021**. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the second quarter of 2021.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,704,216	$5,159,731	49%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$30,822,360	$2,156,501	6%
3. Constable Hook	*Removed from ES 2 Program**						
3. Front Street	Study	$23,000,000	$4,400,000	$27,400,000	$24,472,716	$190,915	1%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,307,880	$2,020,326	9%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$381,286	5%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$956,178	2%
7. Leonia	Conceptual	$25,000,000	$2,500,000	$27,500,000	$25,007,945	$13,034,343	47%
8. Market Street	Definitive	$25,200,000	$1,700,000	$26,900,000	$29,385,009	$23,514,129	87%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,397,100	$786,103	9%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$15,240,393	$594,041	3%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$25,515,519	$13,319,925	48%
12. Ridgefield 4kV	Definitive	$18,500,000	$1,000,000	$19,500,000	$21,202,217	$18,751,152	96%
13. State Street	Study	$19,300,000	$3,100,000	$22,400,000	$19,053,000	$1,193,633	5%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$963,752	5%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$35,070,653	$6,062,028	17%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,255,000	$1,519,097	8%
Subprogram Total		**$326,300,000**	**$51,000,000**	**$377,300,000**	**$346,463,155**	**$90,603,138**	**24%**

***-As of the end of the second quarter of 2021, the cancelled Constable Hook project had an estimate of $5.3 million and had incurred $133,616 in spend that will be removed from the ES 2 Program, the estimated costs and actual spend for Constable Hook is not included in **Table 11**.*

Findings & Observations

- Six of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the second quarter of 2021, with two advancing and four slipping. Of these six projects, four of the projects (Market Street, Ridgefield 4kV, Ridgefield 13kV, and Orange Valley) had forecasted in-service dates change by less than two weeks. The Clay Street forecasted in-service date advanced 50 days from the status as of the end of the first quarter of 2021. Only one project (Waverly) had movement more than 60 days, which saw the in-service date slip an additional 92 days from the forecasted in-service date at the end of the prior quarter, which continues to reflect the impacts of the project's site plan denial in March 2021.
- The Ridgefield 4kV project became the first in the subprogram to be placed fully in-service, with the in-service date achieved on May 16, 2021.
- Five projects had new estimates approved by the URB during the second quarter of 2021, including: the Clay Street project advancing to the Conceptual level with a new estimate of $33.8 million (decreasing $8.2 million from the prior estimate); the Hasbrouck Heights project advancing to the Conceptual level with a new estimate of $22.7 million (increasing $4.7 million from the prior estimate); the Leonia project advancing to the Conceptual level with a new estimate of $27.5 million (decreasing $4.7 million from the prior estimate); the Ridgefield 13kV project advancing to the Conceptual level with a new estimate of $25.5 million (increasing $2.1 million from the prior estimate); and the State Street project with a new Study level estimate that reflects the scope change that removed the OP portion of the project (added as a life cycle station upgrade project) and resulted in a new estimate of $22.4 million (decreasing $22.7 million from the prior estimate).

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the second quarter of 2021, the Waverly project shows a final in-service date in December 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from December 2022 (26kV switchgear) to December 2024 (Transformer #3). PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the second quarter of 2021, $405,843 was spent on the Academy Street project compared to a forecast of approximately $373,000, which brought the total spend to approximately $5.2 million. The forecasted in-service date for the Academy Street project continues to remain October 25, 2021, which is unchanged from the previous quarter.

The primary activity conducted during the first quarter of 2021 on the Academy Street project was the continued advancement of construction activities. Construction, which started in July 2020 for non-permit work on Academy Street, advanced 10% during the second quarter to reach 75% complete inside plant (100% complete OP), while the total project is reported at 84% complete as of the end of the second quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$150,398	$4,224,550	$378,939	$405,843	$912,107	$1,531,237	$2,101,141

Actuals to Date	Estimate	% of Actuals to Estimate
$5,159,731	$10,500,000	49%

2. Clay Street

During the second quarter of 2021, $595,723 was spent on the Clay Street project compared to a forecast of approximately $639,000, which brought the total spend to approximately $2.2 million. The forecasted in-service date for the Clay Street project advanced from February 7, 2023, as of the end of the first quarter of 2021 to December 19, 2022, as of the end of the second quarter of 2021.

The primary activities on the Clay Street project during the second quarter of 2021 included the IFC release of civil drawings (foundation) and electrical and control drawings. The project team also submitted an updated estimate that transitioned to the 70%/Conceptual level with a total estimate of $33.8 million that represented a $8.2 million decrease from the prior estimate. The $8.2 million reduction was driven by a $3.7 million reduction to R&C based on the current risk profile for the project and a $4.5 million reduction to the base estimate, which was the result of:

- Scope change for wastewater wall: -$6.8 million[1]
- Engineering contract lower than previously estimated: -$0.5 million
- Environmental costs higher than previously estimated: $0.3 million
- Revised commissioning estimate: $0.4 million
- Revised Division cutover estimate: $0.5 million
- Switchgear equipment award higher than estimated: $1.6 million

While the updated estimate resulted in a $8.2 million decrease from the prior estimate, the total forecast for the project increased from $29.8 million as of the end of the first quarter of 2021 to $30.8 million as of the end of the second quarter of 2021. This $1.0 million forecast increase was driven by higher than previously estimated cutover costs based on an updated estimate from the Division ($0.5 million) and an increase in surcharge rates based on the 2020 surcharge methodology ($0.5 million).

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$116,409	$879,339	$565,030	$595,723	$1,387,173	$8,023,416	$19,255,270

Actuals to Date	Estimate	% of Actuals to Estimate
$2,156,501	$33,800,000	6%

3. Front Street

As discussed in the IM 2020 Fourth Quarter Report, the Constable Hook project was removed from the ES 2 Program. During the second quarter of 2021, PSE&G presented the Front Street project as a replacement for the cancelled Constable Hook project within the Electric Station Flood Mitigation subprogram. The Front Street substation was originally constructed in 1957 and much of its equipment is the originally installed equipment, which contributed to the substation ranking in the worst 33% of all distribution substations (as of April 2019). While the scope of this proposed project involves life cycle upgrades, it also has a flood mitigation component as the new equipment will be installed in accordance with flood hazard rules (where the existing equipment is situated two feet below the New Jersey Department of Environmental Protection (NJDEP) flood hazard area level). The Front Street project saw its Study level estimate approved by the URB in April 2021, with a total estimate of $27.4 million, comprised of a base estimate of $23.0 million and R&C set at $4.4 million. The IM understands that as of the fourth quarter of 2021 the formal regulatory process of adding this substation to the ES 2 Program continues.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$0	$0	$190,915	$360,764	$322,538	$23,598,499

[1] The ROD on this change was discussed in the IM 2020 Fourth Quarter Report, Section IV.A.

Actuals to Date	Estimate	% of Actuals to Estimate
$190,915	$27,400,000	1%

4. Hasbrouck Heights

During the second quarter of 2021, $189,748 was spent on the Hasbrouck Heights project compared to a forecast of approximately $193,000, which brought the total spend to approximately $2.0 million. The forecasted in-service date for the Hasbrouck Heights project continues to remain February 7, 2023, which is unchanged from the previous quarter. Notable activities completed during the second quarter of 2021 included:

- Electrical construction PO issued;
- Control drawings IFC; and,
- Construction permits issued.

During the second quarter of 2021, the project team also submitted an updated estimate that transitioned to the Conceptual estimate level with a total estimate of $22.7 million that represented a $4.7 million increase from the prior estimate. The $4.7 million increase was the result of a $0.9 million reduction to R&C based on the current risk profile for the project and a $5.6 million increase to the base estimate, which was the result of:

- 4kV switchgear awards higher than estimated: $1.6 million;
- Civil construction bids higher than estimated: $1.2 million;
- Higher dewatering estimate: $1.2 million;
- Relay Tech estimate increased based on revised breakers quantity: $1.0 million; and,
- Change in T&D surcharge methodology: $0.6 million (comprised of $0.1 million in outside services electrical construction and $0.5 million in internal labor).

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$149,848	$1,129,934	$550,795	$189,748	$896,791	$4,584,100	$12,806,663

Actuals to Date	Estimate	% of Actuals to Estimate
$2,020,326	$22,700,000	9%

5. Kingsland

During the second quarter of 2021, $36,886 was spent on the Kingsland project compared to a forecast of $56,000, which brought the total spend to $381,285. The forecasted in-service date for the Kingsland project continues to remain October 4, 2023, which is unchanged from the previous quarter. There continued to be minimal activities performed on this project during the second quarter of 2021.

The actual spend by quarter for Kingsland as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$104,112	$209,667	$30,621	$36,886	$253,489	$196,262	$5,587,504

Actuals to Date	Estimate	% of Actuals to Estimate
$381,285	$8,300,000	5%

6. Lakeside Avenue

During the second quarter of 2021, $174,268 was spent on the Lakeside Avenue project compared to a forecast of approximately $125,000. Notable activities completed during the second quarter of 2021 included the issuance of the licensing and permitting package.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$148,943	$453,994	$178,973	$174,268	$102,867	$212,444	$38,084,790

Actuals to Date	Estimate	% of Actuals to Estimate
$956,177	$47,900,000	2%

7. Leonia

During the second quarter of 2021, approximately $4.1 million was spent on the Leonia project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $13.0 million. Notable activities completed during the second quarter of 2021 included:

- Control drawings IFC;
- Construction permits issued;
- Civil construction (phase 2) started;
- Demolition of first existing 13kV switchgear started;
- Installation of pipe piles started;
- Switchgear delivered to site and set; and,
- Electrical construction (phase 2) started.

Construction at Leonia, which started in August 2020, has advanced to 57% complete inside plant as of the end of the second quarter of 2021, up from 38% complete as of the end of the prior quarter, with the total project reported at 64% complete.

At the end of the first quarter of 2021 the Conceptual level estimate was developed by the project team, this estimate was approved by the URB in April 2021 and resulted in the total estimate for the project being reduced to $27.5 million from $32.2 million. The reduction in the current estimate was the result of:

- Construction awards lower than estimated: -$4.4 million;
- Change in T&D surcharge methodology: $1.2 million (comprised of $0.6 million in outside services electrical construction and $0.6 million in internal labor); and,

- Higher design and engineering hours than estimated: $0.5 million.

In addition, the R&C amount was reduced by $2.0 million based on the current risk profile for the project.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,188,203	$1,827,066	$8,958,332

Actuals to Date	Estimate	% of Actuals to Estimate
$13,034,343	$27,500,000	47%

8. Market Street

During the second quarter of 2021, $3,147,454 was spent on the Market Street project compared to a forecast of approximately $3.4 million, which brought the total spend to approximately $23.5 million. Notable activities completed during the second quarter of 2021 included the commencement and completion of OP 4kV to 13kV conversion work, which puts the Market Street project partially in-service with the final in-service forecasted for September 2021 when the 26kV reconfiguration work is completed (see additional discussion on the Market Street in-service date within **Section IV.A.**).

Construction at Market Street, which started in August 2020, advanced to 90% complete OP as of the end of the second quarter of 2021, up from 75% as of the end of the prior quarter. Inside plant construction is anticipated to being in September 2021 and the overall project is reported at 77% complete as of the end of the second quarter of 2021.

The total forecast for the Market Street project increased from $26.1 million as of the end of the first quarter of 2021 to $29.3 million as of the end of the second quarter of 2021. This forecast increase was driven by additional OP overhead and restoration work along with the associated material and surcharges based on the complexity of the work and the field conditions, including higher than estimated traffic control costs as per city/county requirements.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$251,193	$16,079,601	$4,035,880	$3,147,454	$3,764,648	$1,076,627	$1,029,606

Actuals to Date	Estimate	% of Actuals to Estimate
$23,514,128	$26,900,000	87%

9. Meadow Road

During the second quarter of 2021, $70,220 was spent on the Meadow Road project compared to a forecast of $84,000, which brought the total spend to approximately $786,000. While preliminary design work progressed during the second quarter of 2021, there continued to be minimal other activities on the

Meadow Road project during the second quarter of 2021, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$63,128	$535,081	$117,672	$70,220	$69,000	$76,000	$6,465,998

Actuals to Date	Estimate	% of Actuals to Estimate
$786,102	$9,000,000	9%

10. Orange Valley

During the second quarter of 2021, $146,827 was spent on the Orange Valley project compared to a forecast of approximately $69,000, which bought the total spend to approximately $594,000. The variance in first quarter spend was primarily the result of the key drawing package being completed early (anticipated for July and completed in June). Other activities completed during the second quarter of 2021 included the issuance of license and permitting packages and the award of the switchgear PO, with the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$77,029	$362,895	$7,291	$146,827	$103,425	$115,980	$14,426,947

Actuals to Date	Estimate	% of Actuals to Estimate
$594,041	$20,200,000	3%

11. Ridgefield 13kV

During the second quarter of 2021, $3,665,283 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $13.3 million. Notable activities completed during the second quarter of 2021 included:

- Civil construction (phase 2) bid and PO issued;
- Demolition of first existing 13kV switchgear;
- Phase 1/2 electrical permits issued;
- Switchgear delivered to site;
- Controls drawings IFC; and,
- Piles installation commenced.

Construction at Ridgefield 13kV advanced to 58% complete inside plant as of the end of the second quarter of 2021, compared to 33% complete at the end of the prior quarter, with the total project at a reported 62% completion.

During the second quarter of 2021, the project team also submitted an updated estimate that transitioned to the Conceptual estimate level with a total estimate of $27.6 million that represented a $2.1 million increase from the prior estimate. The $2.1 million increase was the result of a $3.6 million reduction to R&C based on the current risk profile for the project and a $5.7 million increase to the base estimate, which was the result of:

- Procuring contingency switchgear and associated miscellaneous material and cutover work: $2.4 million;
- Change in T&D surcharge methodology: $1.7 million (comprised of $0.6 million in outside services electrical construction and $1.1 million in internal labor);
- Construction supervision and support based on scope and duration: $0.8 million;
- Phase 1 civil construction award higher than estimated: $0.4 million; and,
- Permanent switchgear awards higher than estimated: $0.4 million.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$205,982	$6,232,692	$3,215,967	$3,665,283	$2,435,520	$1,548,363	$8,211,711

Actuals to Date	Estimate	% of Actuals to Estimate
$13,319,925	$27,600,000	48%

12. Ridgefield 4kV

During the second quarter of 2021, $4,559,439 was spent on the Ridgefield 4kV project compared to a forecast of approximately $4.1 million, which brought the total spend to approximately $18.8 million. The variance in spend this quarter was driven by additional cable, splicing and labor required as a result of rerouting two underground circuits around an existing gas main and the need to rebuild secondary buses in order to complete four 13kV conversions, which was partially offset by part of the Division's paving work postponed until July due to township work-hour restrictions. Activities completed during the second quarter of 2021 on the Ridgefield 4kV project included the commencement and completion of 4kV to 13kV conversion work, with the project being placed in-service as of May 16, 2021. The total project is reported at 85% complete as of the end of the second quarter of 2021, up from 81% complete as of the end of the prior quarter.

The total forecast for the Ridgefield 4kV increased from $18.8 million as of the end of the first quarter of 2021 to $21.2 million as of the end of the second quarter of 2021. This forecast increase was driven by additional engineering and overhead labor required to remove primary wires and complete the 4-13kV conversions; the contract for manhole rebuild work was awarded higher than estimated; and additional labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main that was not known at the time of the prior estimate.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,931,069	$459,997	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$18,751,152	$19,500,000	96%

13. State Street

During the second quarter of 2021, $216,479 was spent on the State Street project compared to a forecast of approximately $178,000, which brought the total spend to approximately $1.2 million. The activities performed on State Street during the second quarter of 2021 included the issuance of construction permits and civil and electrical construction POs awarded.

A new Study level estimate was submitted and approved by the URB during the second quarter of 2021. This updated estimate reduced the total project estimate from $45.1 million to $22.4 million, driven by the release of $19.7 million in base and $3.0 million of R&C following the OP scope change that will see that scope of work funded under a new project. The OP work associated with the State Street project, estimated at $22.7 million, is now part of the Electric Stipulated Base (see **Section II.E.5.**).

The State Street scope within the Electric Station Flood Mitigation subprogram involves the relocation of the State Street substation from its current site to the new location identified at Cooper Street. The State Street OP scope being executed under the Electric Stipulated Base involves the extensive underground installation required to connect the new 4kV circuits back to the existing 4kV circuits and to maintain the current capacity of these circuits. PSE&G informed the IM that discussions it had with BPU Staff and Rate Counsel regarding the mitigation change on the State Street project resulted in the decision to recover the increased cost for the State Street project stemming from the change in mitigation method (then estimated at $16.5 million) in the Company's next rate case as opposed to the ES 2 accelerated recovery. PSE&G's view is that while these increased costs on State Street are prudent and can and should be recovered by way of the accelerated recovery mechanism, it will in this one circumstance defer its request for recovery and credit the additional cost associated with the State Street OP scope toward the Company's stipulated base requirements for the ES 2 Program.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$77,590	$662,148	$237,415	$216,479	$6,071,171	$1,473,376	$10,314,820

Actuals to Date	Estimate	% of Actuals to Estimate
$1,193,633	$22,400,000	5%

14. Toney's Brook

During the second quarter of 2021, $289,769 was spent on the Toney's Brook project compared to a forecast of approximately $400,000, which brought the total spend to approximately $1.0 million. The variance in spend this quarter was driven by the civil/layout issued for review (IFR) milestone not

completed in June as assumed, however there was no resulting change to the forecasted in-service date. Notable activities completed during the second quarter of 2021 included the release of civil and electrical IFC drawings.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$211,940	$373,096	$88,947	$289,769	$195,119	$211,127	$14,884,332

Actuals to Date	Estimate	% of Actuals to Estimate
$963,751	$18,800,000	5%

15. Waverly

During the second quarter of 2021, $2,837,893 was spent on the Waverly project compared to a forecast of approximately $3.1 million, which brought the total spend to approximately $6.1 million. The majority of the actual spend during the second quarter of 2021 was associated with the delivery of the 26kV switchgear in April 2021 ($2.3 million), with the remaining spend in the quarter related to project support costs (Project Management, licensing and permitting) of $0.2 million, engineering costs of $0.2 million, and A/E procured equipment of $0.15 million. The variance in second quarter forecasted to actual spend was largely driven by material shortages (conduit) that pushed the start of Metro Division activities into the third quarter.

As reported in the IM 2021 First Quarter Report, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The revised site plan continued to be developed through the second quarter of 2021, including receiving feedback from the community at outreach meetings held this quarter. Due to the site plan not being approved in the March 2021 meeting, the entire project has shifted out, including pushing the in-service date from the fourth quarter of 2023 to the fourth quarter of 2024 (for transformer #3, which is the final asset). PSE&G is continuing to look at opportunities to reduce the activity durations and pull the schedule back.

Construction at Waverly, which started in October 2020, was paused with the site plan denial and remains at 6% complete as of the end of the second quarter of 2021.

The total forecast for the Ridgefield 4kV increased from $33.8 million as of the end of the first quarter of 2021 to $35.0 million as of the end of the second quarter of 2021. This forecast increase was driven by higher carrying costs based on the extended project duration stemming from the initial site plan denial, along with additional engineering and licensing and permitting costs related to performing the required site plan revisions.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals				*Forecast*		
$103,748	$2,460,815	$659,572	$2,837,893	$498,727	$573,923	$27,935,974

Actuals to Date	Estimate	% of Actuals to Estimate
$6,062,028	$35,400,000	17%

16. Woodlynne

During the second quarter of 2021, $132,630 was spent on the Woodlynne project compared to a forecast of approximately $122,000, which brought the total spend to approximately $1.5 million. Notable activities completed during the second quarter of 2021 included the issuance of construction permits and civil and electrical POs issued.

The total forecast for the Woodlynne increased from $18.3 million as of the end of the first quarter of 2021 to $21.2 million as of the end of the second quarter of 2021. This forecast increase was driven by higher than previously estimated civil construction work, which was slightly offset by lower in-house engineering costs and lower than estimated costs of piles procurement.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$110,982	$993,298	$282,187	$132,630	$1,215,299	$1,247,199	$17,273,405

Actuals to Date	Estimate	% of Actuals to Estimate
$1,519,097	$19,400,000	8%

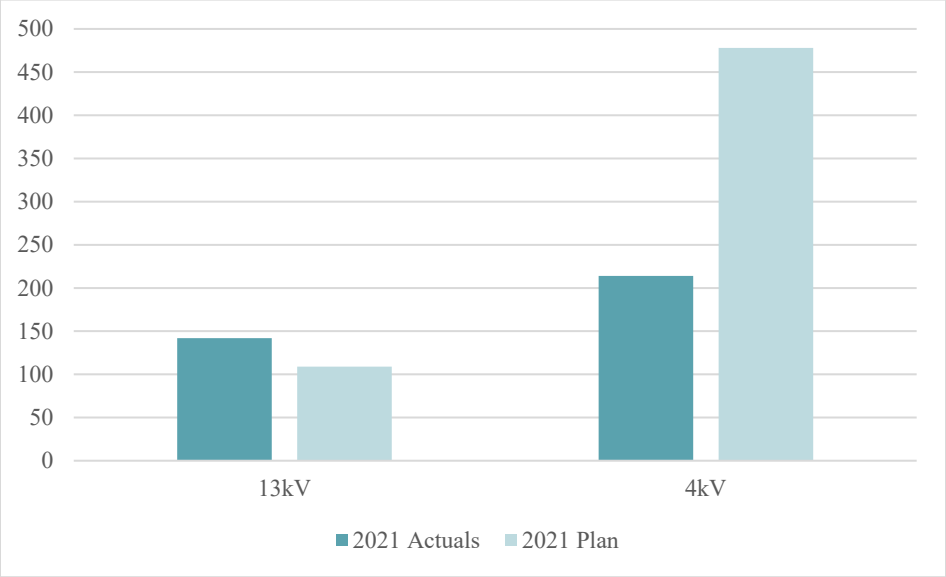
B. Contingency Reconfiguration

During the second quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 193 installed during the quarter and 179 commissioned. **Table 12 – ES 2 Program Recloser Status as of June 30, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of June 30, 2021** compares the installed reclosers as of the end of the second quarter of 2021 against PSE&G's 2021 installation plan.

Table 12 – ES 2 Program Recloser Status as of June 30, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q2 Qty.	*2021 Total*	*Program Total*	*Q2 Qty.*	*2021 Total*	*Program Total*	*Q2 Qty.*	*2021 Total*	*Program Total*
13kV	94	146	845	95	142	803	85	136	780
4kV	111	188	442	98	214	371	94	210	367
Total	205	334	1,287	193	356	1,174	179	346	1,147

Figure 3 – 2021 Recloser Installations as of June 30, 2021



As shown in **Table 13** and **Figure 3**, PSE&G continued to maintain progress during the second quarter of 2021 and stayed on track for the 2021. As discussed in the IM 2021 First Quarter Report, there was an identified resource constraints within the Metro Division that stemmed from attrition at the end of the year and two larger projects in the Division with firm in-service dates, leading to a shortage of approximately 30 full-time equivalents compared to normal. While new hires have been brought on board, they will not be able to work on crews until their training is completed. To mitigate impacts, PSE&G engaged a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021. As also shown in **Figure 3**, the 2021 installation plan shifts the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. However, actual installations of 13kV reclosers will continue above the initial 2021 plan due to the change in reclosers planned for the subprogram following PSE&G's review, which resulted in an additional 275 13kV reclosers and 90 4kV reclosers (also discussed in Section IV.A.1. of the IM 2021 First Quarter Report and **Section II.A.1.** of this IM 2021 Second Quarter Report).

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[2] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. As noted in the IM 2020 Second Quarter Report, PSE&G's Asset Management group determined a pilot program would be initiated prior to the full scope to ensure these new devices work as intended. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the SCADA communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will

[2] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

monitor to ensure it addresses the issues prior to placing additional orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021, as it awaits approval by PSE&G's Asset Management group to proceed with the full scope, aside from the installation of additional units from existing stock. A final decision on the Fuse Saver scope is expected to be made before the end of 2021.

The current forecasted final in-service dates for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2021**. This table also shows the forecasted dates as of the end of the first quarter of 2021 to show movement to the forecast as of the end of the second quarter of 2021.

Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2021

Scope & Division		Q1 2021 Forecasted Completion Date	Q2 2021 Forecasted Completion Date
Reclosers	Central	12/31/2021	1/31/2022
	Metro	12/31/2021	1/31/2022
	Palisades	11/30/2021	10/31/2021
	Southern	12/31/2021	1/31/2022
Fuse Savers	Central	12/30/2023	12/30/2023
	Metro	12/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	12/30/2023

As shown in **Table 13**, the forecasted final in-service date for each Division's Fuse Saver program remained constant as PSE&G continues its evaluation of the Fuse Saver pilot program before making a final scope decision. While the recloser scope of work saw minor movement across each Division (three slipping one month, one advancing one month from the prior quarter), which was driven by the current scope and status in each Division.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2021 are presented in **Table 14 – ES 2 Contingency Reconfiguration Costs as of June 30, 2021**.

Table 14 – Contingency Reconfiguration Costs as of June 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$20,188,282	$25,054,781	81%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$17,597,154	$23,888,564	74%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$20,335,714	$23,161,122	88%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$23,560,938	$28,952,061	81%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$1,283,102	$12,463,404	10%
	Metro	$7,557	$561,915	$216,511	$89,860	$875,843	$11,526,731	8%
	Palisades	$7,468	$522,454	$133,552	$63,808	$727,282	$8,833,380	8%
	Southern	$9,792	$859,014	$65,018	$56,845	$990,669	$13,190,192	8%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$85,558,985**	**$147,070,235**	**58%**

Findings & Observations:

- PSE&G continued to maintain progress during the second quarter of 2021 and stayed on track for the 2021, assisted by the engagement of a pole setting contractor to alleviate resource constraints in the Metro Division.
- As previously reported, 80 Fuse Saver devices were installed as part of the pilot program for these devices. PSE&G is monitoring the performance of these initial devices after encountering communication issues on approximately 10% of the installed units. The solution developed with Siemens utilizes an external antenna to improve communications.
- The forecasted completion of the recloser scope of this subprogram saw some adjustment during the second quarter of 2021 with most Divisions seeing an approximate one month slip to the completion of the recloser scope, other than the Palisades Division that saw the 13kV recloser completion date improve by 30 days and no change to the 4kV recloser completion date, and the 4kV completion date for the Southern Division, which slipped 92 days based on the engineering package readiness (specifically for tie reclosers). For the Fuse Savers, there was no change to the forecasted completion dates during the second quarter of 2021 while PSE&G continues to assess its final decision on the scope of this work.
- The Contingency Reconfiguration subprogram forecast remained fairly constant as of the end of the second quarter, with a slight decrease of approximately $1.9 million from the first quarter of 2021. This was largely driven by a net 14-unit reduction in the number of 13kV reclosers planned based on the current status of the network.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. No overall impacts are expected from this decision and PSE&G plans to regain the planned retrofit installations by the middle of 2021 as it shifts focus from new recloser installations to the retrofit reclosers. During the second quarter of 2021, retrofit installations continued to ramp up with 684 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter out of a total program forecast of 2,364 (which is periodically reviewed and updated).

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations (see additional post-second quarter of 2021 information on the approved fiber projects in **Section IV.B.**). The list of identified fiber installation and cutover projects is presented in **Table 15 – Fiber Projects by Division**.

Table 15 – Fiber Projects by Division

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***

During the second quarter of 2021, one additional fiber installation projects (Roselle) was placed in-service. This brought the total projects in-service as of the end of the second quarter of 2021 to nine for the fiber installation projects and eight for the fiber cutover projects. **Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the second quarter of 2021 and the projects in italics represent those placed in-service.

Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021

Project Name	Q2 2021 Status	Budget*	Forecast**
Fiber Installation Projects			
Bergen Point	*In-Service (Q1 2021)*	$750,000	$701,459
Bloomfield	Continued construction	$300,000	$1,482,687
Bordentown	Inside plant (IP) civil construction completed	$0	$682,285
Carteret	OP construction mobilized; IP civil construction completed	$0	$753,816
Central Ave	IP IFC issued	$480,000	$112,759
Central HQ	IP IFC issued; OP IFC issued	$570,000	$1,800,274
Chauncey Street	OP IFC issued	$840,000	$875,395
Cranford	*In-Service (Q4 2020)*	$300,000	$357,876
Culver Ave	Preliminary engineering	$0	$832,145
East Orange	*In-Service (Q1 2021)*	$480,000	$1,143,568
Edison	Preliminary engineering	$0	$1,070,066
Elizabeth Sub HQ	*In-Service (Q1 2021)*	$555,000	$749,712
First Street	OP construction completed; IP IFC issued	$300,000	$618,118
Fort Lee	Continued construction	$480,000	$1,263,941
Hackensack Sub HQ	*In-Service (Q4 2020)*	$825,000	$595,412
Haddon Heights	Preliminary engineering	$0	$738,942
Hadley Rd HQ	IP civil construction completed	$0	$1,460,786
Haledon	IP IFC issued; OP construction mobilized	$300,000	$567,567
Harrison	IP construction mobilized	$300,000	$576,805
Howell Street	Preliminary engineering [see also updated status in **Section IV.B.**]	$0	$0
Irvington	OP construction mobilized	$300,000	$174,633
Irvington Sub HQ	OP IFC issued; OP Construction mobilized	$300,000	$601,657
Keasbey	Preliminary engineering	$840,000	$784,856

Project Name	Q2 2021 Status	Budget*	Forecast**
Lehigh Avenue	Preliminary engineering	$0	$818,014
Mechanic Street	Preliminary engineering	$1,200,000	$925,256
Metro HQ	*In-Service (Q1 2021)*	$300,000	$582,568
Montclair	OP IFC issued	$840,000	$2,147,782
Morgan Street	IP IFC issued; IP construction mobilized; OP IFC issued	$0	$518,181
Norfolk St	IP IFC issued	$300,000	$186,265
Palisades HQ	Continued construction	$255,000	$409,690
Princeton	OP construction completed	$300,000	$1,132,137
Rahway	*In-Service (Q1 2021)*	$390,000	$1,026,601
Ridgewood	OP IFC issued	$390,000	$483,367
Roselle	*In-Service (Q2 2021)*	$390,000	$428,183
So Orange	OP IFC issued; OP construction mobilized; OP construction completed	$390,000	$312,099
Southern HQ	*In-Service (Q4 2020)*	$570,000	$708,350
Thirty Second Street	Preliminary engineering	$0	$0
Waverly	Preliminary engineering; project being rescheduled to align with the completion of the new control house as part of the Waverly substation project under the Electric Station Flood Mitigation subprogram.	$300,000	$439,640
West New York	IP IFC issued	$300,000	$997,565
Fiber Cutover Projects***			
Delair	*In-Service (Q4 2020)*	$50,000	$117,340
East Riverton	*In-Service (Q4 2020)*	$50,000	$117,340
Elizabeth	*In-Service (Q1 2021)*	$50,000	$215,592
Fairview	Completion dependent upon Fort Lee fiber installation project (tentative start of construction in September 2021)	$50,000	$89,786
Henry St	Battery rack installation pending; site visit with Central Division scheduled	$50,000	$215,592
Mount Holly	*In-Service (Q4 2020)*	$50,000	$117,340
Polk Street	Completion dependent upon West New York fiber installation project (engineering in progress)	$50,000	$89,786
Riverside	*In-Service (Q4 2020)*	$50,000	$117,340
Spring Valley Rd	*In-Service (Q1 2021)*	$50,000	$89,786
Tonnelle Ave	*In-Service (Q4 2020)*	$50,000	$89,786
Union City	*In-Service (Q1 2021)*	$50,000	$89,786
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)	$50,000	$56,866
Substation Remote Terminal Unit (RTU) Cutovers			
Scope: 204 units	5 cutovers completed	$1,540,000	$1,929,597

**-The fiber projects with $0 budgets were not part of the original project list and were added to the subprogram following PSE&G's review of the fiber requirements and status of all its substations and operation centers (see Section IV.A. of the IM 2020 Third Quarter Report), subject to the availability of funds.*

***-The forecast data is the current forecast information received as of the date of this report (i.e. it reflects the forecast as of early 2022). For the projects with a $0 forecast, these have been either identified for removal (Howell Street) or were projects identified as potential additions to the subprogram that are unlikely to advance due to lack of additional funds (Thirty Second Street).*

****-The cutover projects have budgets authorized and tracked by Division. Thus, costs for each station are calculated by taking the budget/forecast for a Division and dividing by the number of stations in the scope for that Division.*

During the second quarter of 2021, updated estimates for the wireless network and retrofits scope (Conceptual level estimate) and for the fiber installation and substation cutover scope (Study level estimate) were approved by the URB. The wireless network and retrofits scope saw its total estimate decrease from $48.6 million as originally approved to $35.1 million. This $13.5 million reduction was driven by the selection of FirstNet as the wireless network vendor in lieu of the original plan to build a solely owned and operated private network.[3] The fiber installation and substation cutover scope saw its total estimate increase from $23.4 million to $27.5 million. This $4.1 million increase was the result of a comprehensive review of the fiber requirements and status of all PSE&G substations and Operations Centers that refined the scope based on current communication needs from what was identified in the original ES 2 filing.

The Grid Modernization – Communication System subprogram costs through the end of the second quarter of 2021 are presented in **Table 17 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2021**.

Table 17 – ES 2 Grid Modernization – Communication System Costs as of June 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$2,979,175	$6,872,724	43%
	Metro	$0	$818,620	$436,089	$683,893	$1,938,602	$5,762,666	34%
	Palisades	$0	$825,174	$754,869	$965,416	$2,545,459	$6,349,520	40%
	Southern	$0	$929,058	$956,444	$1,005,852	$2,891,354	$7,124,742	41%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$4,566,535	$7,790,984	59%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$3,040,204	$7,230,419	42%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$3,021,932	$4,822,458	63%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$2,589,590	$3,569,301	73%
	Cutovers*	$0	$876,502	$323,458	$86,115	$1,286,075	$2,945,462	44%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$6,709,236	$7,909,532	85%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	$1,820,850	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,176**	**$33,389,011**	**$60,377,806**	**78%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Findings & Observations:

- During the second quarter of 2021, retrofit installations continued to advance following the ramp-up earlier in 2021 with 685 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter of 2021 out of a total program forecast of 2,364 (which continues to be periodically reviewed and updated).
- One additional fiber installation project was placed in-service during the second quarter of 2021, bringing the total number of projects in-service to nine fiber installation projects and eight fiber cutover projects.
- An updated Grid Modernization – Communication System subprogram estimate was approved by the URB during the second quarter of 2021, which resulted in the wireless network & retrofits

[3] See related discussion in Section II.A.1. of the IM 2020 Third Quarter Report.

estimate decreasing by $13.5 million to $35.1 million, driven by the savings realized in the wireless network vendor selection. The fiber scope estimate increased $4.1 million to $27.5 million, which was driven by an updated review of the fiber and communication requirements and current status of all PSE&G substations and Operations Centers. Collectively with the updated estimate to the Grid Modernization – ADMS subprogram, there was no net change to the total estimate of the two Grid Modernization subprograms (after the addition of $1.7 million as a placeholder for future subprogram needs).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the second quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q2 2021 Activities:
  - Reviewed program development system configuration.
  - Conducted 3rd party interface requirement meetings.
  - Received AMI and weather interface software and license pricing.
  - Conducted factory acceptance testing activities.
- Forecasted Completion as of the end of the second quarter of 2021: 12/9/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tolls for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q2 2021 Activities:
  - Completed legacy data for conversion requirements.
  - Completed Power BI training session.
  - Conducted feedback sessions with Divisions.
  - Conducted design review workshops.
  - Reviewed list of reports to finalize reporting requirements.
  - Drafted damage assessment process and design.
- Forecasted Completion as of the end of the second quarter of 2021: 12/2/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q2 2021 Activities:
  - Approved test lead candidate for cognizant.
- Forecasted In-Service as of the end of the second quarter of 2021: 12/10/2021.

During the second quarter of 2021, the Grid Modernization – ADMS subprogram transitioned to a Conceptual level estimate that was approved by the URB at $42.7 million, an increase of $7.7 million from the prior $35.0 million estimate. The increase was primarily the result of a more refined scope, including:

- Increased interface and hardware architecture requirements identified since the original ES 2 filing ($5.4 million); and,
- Increased performance testing scope requirements as a result of lessons learned from Tropical Storm Isaias ($2.3 million).[4]

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2021 are presented in **Table 18 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2021**.

Table 18 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals				*Forecast*		
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,916,157	$3,477,015	$15,178,439

Actuals to Date	Forecast	% of Actuals to Forecast
$21,141,005	$42,712,616	49%

Findings & Observations:

- The resource constraints continue to be monitored by PSE&G but have not led to additional issues. During the second quarter of 2021 a new ADMS test lead was also brought on board.
- The Grid Modernization – ADMS forecast increased approximately $2.3 million during the second quarter of 2021 from the end of the first quarter of 2021. This was also reflected in an updated estimate for the subprogram, with this increase driven by additional performance testing scope requirements and an extended schedule as a result of lessons learned from Hurricane Isaias. Likewise, the forecasted completion date for the OMS scope shifted from May 2022 to December 2022 based on the lessons learned.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric OP higher design and construction standards and/or

[4] See related discussion in Section IV.A.2. of the IM 2021 First Quarter Report and in **Section II.A.2.** of this IM 2021 Second Quarter Report.

electric stations life cycle subprograms described in the original ES 2 filing.[5] The bulk of OP higher design and construction standards work is planned to commence in January 2022, which will involve the hardening of selected 13kV circuits with poor storm performance by changing the construction standard from cross-arm open wire to spacer cable construction. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its OP scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 19 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2021**.

Table 19 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$1,000,011	6%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$5,376,035	27%	11/15/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$1,264,500	6%	10/20/2022 (↓)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,447,528	8%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$17,633	0%	3/15/2023

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 19**, of the four prior life cycle station upgrade projects, both the Paramus and Plainfield projects saw a slight slip of 8 and 14 days, respectively, to the forecasted in-service date. Given the relatively small magnitude of these changes, the IM has not performed additional schedule analyses on these projects but will continue to monitor for potential trends. The State Street OP project has its initial forecasted in-service date set for March 15, 2023. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- The primary activities during the second quarter of 2021 continued to center around advancing the engineering and procurement for the life cycle station upgrade projects. The Paramus project also became the first of these stations to commence construction.

[5] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

- The Hamilton and Woodbury projects saw their forecasts increase by 11% and 19%, respectively, from the end of the first quarter of 2021. On Hamilton, the increase was driven by a higher than previously estimated civil construction costs; while on Woodbury, the increase was driven by updated estimates for electrical construction, testing and commissioning, wire checkers costs, Division support, and a correction to the total switchgear PO value. Despite these increases, the current forecasts for both projects remain below their respective estimates.
- There was minor movement to the forecasted in-service dates for the Paramus and Plainfield projects during the second quarter of 2021, with Paramus slipping 8 days and Plainfield slipping 14 days from the forecasted in-service date as of the end of the first quarter. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022.
- One new life cycle station upgrade project, State Street (OP), was added to the Electric Stipulated Base set of projects. This OP scope was originally part of the State Street project within the Electric Station Flood Mitigation subprogram but was split out in accordance with PSE&G's notice of mitigation change on the original State Street project.

1. Hamilton

During the second quarter of 2021, $400,855 was spent on the Hamilton project against a forecast of approximately $388,000. This brought total spend through the end of the second quarter of 2021 on the project to approximately $1.0 million. Notable activities conducted during the second quarter of 2021 included:

- Civil and electrical drawings IFC; and,
- Civil construction out for bid.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$362,372	$236,783	$400,855	$1,044,531	$1,703,282	$12,455,452

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,000,011	$18,200,000	$16,203,276	6%

2. Paramus

During the second quarter of 2021, $4,176,989 was spent on the Paramus project against a forecast of approximately $4.1 million. This brought total spend through the end of the second quarter of 2021 on the project to approximately $5.4 million. Notable activities conducted during the second quarter of 2021 included:

- Civil construction start (contingency switchgear);
- Electrical construction PO issued and start of electrical construction; and,
- Partial 4kV contingency feeder rows delivered.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$840,200	$358,846	$4,176,989	$1,215,200	$1,314,500	$11,108,617

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$5,376,035	$20,200,000	$19,014,352	27%

3. Plainfield

During the second quarter of 2021, $367,543 was spent on the Plainfield project against a forecast of approximately $914,000. The variance between actual and forecasted spend was largely the result of Division work planned for June that was shifted to July-August due to weather constraints (which contributed to the 14-day slip in the in-service date noted above). This brought total spend through the end of the second quarter of 2021 on the project to approximately $900,000. Notable activities conducted during the second quarter of 2021 included civil and electrical drawings IFC.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals				*Forecast*		
$0	$682,325	$214,632	$367,543	$1,787,346	$1,202,569	$15,390,900

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,264,500	$22,600,000	$19,645,315	4%

4. Woodbury

During the second quarter of 2021, $356,225 was spent on the Woodbury project against a forecast of approximately $356,000. This brought the total spend on the project to approximately $1.4 million. Notable activities conducted during the second quarter of 2021 included:

- Planning board hearing and permits issued;
- Controls drawings IFC; and,
- Civil and electrical construction out for bid.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$551,165	$540,138	$356,225	$228,137	$633,995	$15,590,340

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,447,528	$18,700,000	$17,900,000	6%

5. State Street (Outside Plant)

The scope of work for the State Street OP project is comprised of new 4kV OP underground and overhead distribution equipment including manholes and duct banks as required to connect the existing State Street 4kV circuits to the new State Street substation located at Cooper Street.

During the second quarter of 2021, $17,633 was spent on the State Street (OP) project against a forecast of approximately $128,000. This variance was primarily due an error that captured the forecast for July 2021 within the June 2021 forecast. This was the first quarter with spend on this project and the minimal spend to date was related to setting up the project and initial planning efforts.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$0	$0	$0	$17,633	$469,426	$145,608	$19,067,333

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$17,633	$22,700,000	$19,700,000	0%

F. Gas M&R Station Upgrades

Through the end of the second quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the engineering at each station and other pre-construction activities such as reviewing scope and permit documents and performing noise and geotechnical studies. **Table 20 – ES 2 Gas M&R Summary Status as of June 30, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 20 – ES 2 Gas M&R Summary Status as of June 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$1,669,208	6%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$1,182,818	4%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$1,128,559	7%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$673,165	6%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$828,841	6%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$4,736,632	47%	Dec 2021
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$10,219,223**	**9%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

During the second quarter of 2021, the Westampton project saw its 70%/Conceptual level estimate internally approved in May 2021, followed by the URB approval of the 90%/Definitive level estimate in June 2021. The total estimate remains at $10.0 million, unchanged from the prior estimate for the project, but includes $0.8 million released from R&C to the base estimate. There were no changes to the forecasted in-service dates for the Gas M&R project in this period.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including the issuing material procurement POs, performing geotechnical tests and groundwater studies. The Westampton project became the first Gas M&R station to enter construction, which commenced in April 2021 and is forecasted to be complete by the end of the year. Engineering and procurement efforts continued to be a main focus of 2021 second quarter activities at the other stations.
- While still early in the subprogram, the IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. The Westampton project advanced through the Conceptual level estimate to have it Definitive level estimate approved by the URB in June 2021, which resulted in no net change to the project's estimate. The overall subprogram currently has a total forecast of $92 million, which remains under the Stipulation budget of $101 million.

1. Camden

During the second quarter of 2021, $290,839 was spent on the Camden project compared to a forecast of approximately $378,000, which brought the total spend to approximately $1.7 million. Continuing with the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Camden project included:

- Completed geotechnical borings;
- Issued material procurement PO;
- Presented and received conditional zoning board approval; and,
- Received NJDEP Flood Hazard Area (FHA) permit.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$13,326	$859,350	$505,693	$290,839	$1,695,488	$5,650,303	$15,285,001

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,669,208	$29,300,000	$24,300,000	6%

2. Central

During the second quarter of 2021, $190,109 was spent on the Central project compared to a forecast of approximately $247,000, which brought the total spend to approximately $1.2 million. Continuing with the pre-construction efforts, during the second quarter of 2021, notable activities completed on the Central project included:

- Received preliminary cathodic protection drawings for review;
- Issued material procurement PO;
- Completed 3D model review of station design;
- Submitted environmental key plan to township; and,
- Prepared construction bid package.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$6,869	$670,582	$315,258	$190,109	$2,636,014	$7,791,681	$12,289,486

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,182,817	$29,000,000	$23,900,000	4%

3. East Rutherford

During the second quarter of 2021, $260,112 was spent on the East Rutherford project compared to a forecast of approximately $245,000, which brought the total spend to approximately $1.1 million. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the East Rutherford project included:

- Collected water samples for groundwater study and received groundwater study report; and,
- Received Licensing & Permitting drawing package.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$9,010	$521,865	$337,573	$260,112	$234,569	$985,999	$11,450,873

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,128,560	$16,500,000	$13,800,000	7%

4. Mount Laurel

During the second quarter of 2021, $149,682 was spent on the Mount Laurel project compared to a forecast of approximately $122,000, which brought the total spend to approximately $673,000. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Mount Laurel project included:

- Competed soft digs to confirm underground pipe locations;
- Completed page turn of 90% design drawings;
- Performed station boundary survey; and,
- Received information for bidders (IFB) construction drawing package.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$5,965	$362,167	$155,351	$149,682	$441,985	$968,060	$7,316,791

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$673,166	$11,400,000	$9,400,000	6%

5. Paramus

During the second quarter of 2021, $129,694 was spent on the Paramus project compared to a forecast of approximately $142,000, which brought the total spend to approximately $829,000. Continuing the pre-construction efforts, during the second quarter of 2021 notable activities completed on the Paramus project included the issuance of the material procurement PO.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$8,842	$462,452	$277,854	$129,694	$123,989	$82,693	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$828,841	$13,700,000	$11,500,000	6%

6. Westampton

During the second quarter of 2021, $3,217,496 was spent on the Westampton project compared to a forecast of approximately $3.0 million, which brought the total spend to approximately $4.7 million. Construction on the Westampton project commenced in April 2021, while other notable activities completed on the Westampton project during the second quarter of 2021 included:

- Started foundation work and completed data building foundation;
- Received fully executed interconnection agreement with Transco;
- Set data building on foundation;
- Received demolition permits;
- Completed successful hydrotest of all prefabricated piping;
- Completed asbestos remediation at existing regulator building; and,
- Received new regulator building.

During the second quarter of 2021, the project team internally approved the Conceptual level estimate in May 2021 and submitted an updated estimate to the URB in June 2021 that transitioned to the Definitive estimate level with a total estimate of $10.0 million that represented no net change to the total estimate but saw $0.8 million of R&C released into the base estimate. The $0.8 million increase in the base estimate was the result of:

- Increased construction costs based on revised environmental estimates and increased oversight duration ($0.4 million);
- Increased procurement costs based on POs issued ($0.3 million); and,
- Project management, design & engineering, and licensing & permitting adjustments ($0.1 million).

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals				*Forecast*		
$8,395	$1,032,670	$478,072	$3,217,496	$2,252,945	$1,948,690	$161,734

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$4,736,632	$10,000,000	$9,100,000	47%

IV. Additional Information Following the End of the Second Quarter of 2021

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the second quarter of 2021, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information, the IM has provided additional remarks to provide a more complete view of the status of the ES Program based on the available information as of the date of this IM 2021 Second Quarter Report.

A. Market Street In-Service Date

As of the end of the second quarter of 2021, the Market Street in-service was forecasted for September 2021 when the 26kV equipment associated with the 26kV reconfiguration work was to be installed. Following the second quarter of 2021, engineering design was completed for the 26kV reconfiguration, which allowed PSE&G to determine that no new equipment was needed for the reconfiguration, and thus no further in-service date required for the Market Street project beyond the 4kV to 13kV OP conversion scope that was completed as of June 25, 2021.

B. Updated Fiber Projects

During the fourth quarter of 2021, PSE&G's DSCADA and Transmission Fiber Infrastructure (TFI) groups evaluated that the Howell Street fiber project would not provide the redundancy and resiliency benefits that the ES 2 Program aims to obtain, as the Howell Street substation shares a site with the Jerset City switching station that already has a TFI rack that links back to Howell Street, and thus the Howell Street project was removed from the ES 2 Program. This is consistent with the approach used by PSE&G for the fiber projects, which initially identified a pool of 41 fiber installations for the ES 2 Program and previously removed two projects where a future substation elimination is planned. At this time, PSE&G does not anticipate replacing the cancelled fiber projects with new fiber projects.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

MAY 5, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-1	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2021 Report, please provide an update to the Waverly site plan approval process.	The Waverly site plan received unanimous approval during the City of Newark's Planning Board meeting on December 14, 2021. Normally, it would then be memorialized in the next meeting, however, the City attorney was out with Covid-19 at that time, which coupled with a backlog of applications resulted in it not being memorialized until the February 3, 2022 meeting.	No change
RCR-INF-2	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain if the revised and delayed site plan for the Waverly substation will increase projected costs for the project.	As noted in the IM's 2021 First Quarter Report, PSE&G's preliminary office level estimate on the changes resulting from the revised site plan indicate an estimated cost increase of $2.6 million. This is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
RCR-INF-3	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please indicate how many of the 330 reclosers (177 13kV reclosers and 153 4kV reclosers) would be part of the Company's Poorest Performing Circuit program.	Of these 330 reclosers on 238 circuits identified for removal from the ES 2 Program, 54 circuits were part of the last two years Poorest Performing Circuit.	**Section II.A.1.**
RCR-INF-4	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please indicate how many of the 330 reclosers (177 13 kV reclosers and 153 4kV reclosers) are part of some other program that is neither Energy Strong 2 nor the Poorest Performing Circuit program. Please identify the program(s).	Of these 330 recloser on 238 circuits identified for removal from the ES 2 Program, beyond the 54 circuits mentioned in response to RCR-INF-3 as part of the Poorest Performing Circuit initiative, 78 circuits received other reliability enhancements outside of the ES 2 Program.	**Section II.A.1.**
RCR-INF-5	With reference to page 5 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain why the replacement reclosers are skewed towards 13kV reclosers.	The number and type of reclosers added to the Contingency Reconfiguration subprogram was the result of PSE&G's detailed review of 4kV and 13kV circuits that sought to identify cost effective opportunities to include additional circuits in the program in order to improve reliability by reducing the number of customers impacted by an outage and evaluated the options utilizing the same cost benefit process performed for the ES 2 filing.	No change

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>RCR-INF-6</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please describe the gaps in performance testing and the lessons learned by Hurricane Isaias.</td><td>Initially discussed in the IM 2021 First Quarter Report (Section IV.A.2.), the gaps in performance testing on the integrated systems included the OMS experiencing multiple issues with the high volume of data transmitted during the storm, which impacted all communication channels and field management activities. The suspected root cause of the OMS performance issues included: SCADA alarms and customer reports not processed at a rate fast enough to keep up with incoming reports; and stale and repeated outage reports were being submitted erroneously to the OMS when initial submission attempts timed out. The OMS unresponsiveness caused delays to work processes and led to a lower quality of estimated time of recovery information.

Among the lessons learned from this storm were two that specifically impact the OMS implementation:
1. Do not introduce any major system changes immediately before storm season.
2. Ensure enhanced performance testing is conducted for each system and its ecosystem. These tests should be repeated annually, with the proper infrastructure, to ensure reliability and availability of critical systems when they are needed most.
The above lessons learned dictated the following changes to the OMS implementation:
• Shift the deployment date from May 2022 until after the June-September major storm season.
• Increase the services scope for the additional enhanced performance testing expectations.
• Enhance the OMS architecture to ensure separate development/testing environments for the long-term.
• Including contingency to mitigate performance issues in OMS and its ecosystem.</td><td>No change</td></tr>
<tr><td>RCR-INF-7</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please describe the enhanced performance testing in response to Hurricane Isaias.</td><td>See the response to RCR-INF-6 above.</td><td>No change</td></tr>
<tr><td>RCR-INF-8</td><td>With reference to page 5 of the Independent Monitor’s Draft Second Quarter 2021 Report, please explain what portion of the $2.3 million increase in costs is attributed to additional scope and what is attributable to the revised deployment date.</td><td>The estimated $2.3 million cost increase related to the OMS implementation is comprised of the following components:
<table><tr><th>Component</th><th>Cost</th></tr><tr><td>Extend OSI services contract</td><td>$1.5 million</td></tr><tr><td>Extend Cognizant services contract</td><td>$0.2 million</td></tr></table></td><td>Section II.A.2.</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		<table><tr><td>Extend Pontoon services contract</td><td>$0.2 million</td></tr><tr><td>Extend Internal subject matter experts</td><td>$0.2 million</td></tr><tr><td>Development Environment</td><td>$0.2 million</td></tr><tr><td>Development Contingency</td><td>$0.3 million</td></tr><tr><td>Reduced Travel & Expenses</td><td>($0.3 million)</td></tr><tr><td>Total</td><td>$2.3 million</td></tr></table>	
RCR-INF-9	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2011, please explain the increase in the projected cost of the Clay Street Substation from $29.8 to $30.8 million.	The Q1 2021 to Q2 2021 forecast increase on the Clay Street substation project was driven by higher than previously estimated cutover costs based on an updated estimate from the Division ($0.5 million) and an increase in surcharge rates based on the 2020 surcharge methodology ($0.5 million).	**Section III.A.2.**
RCR-INF-10	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Market Street Substation from $26.1 to $29.3 million.	The forecast increase on the Market Street project was driven by additional OP overhead and restoration work along with associated material and surchargers based on the complexity of the work and the field conditions, including higher than estimated traffic control as per city/county requirements.	**Section III.A.8.**
RCR-INF-11	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Ridgefield 4kV Substation from $18.8 to $21.2 million.	The forecast increase on Ridgefield 4kV project was driven by: additional engineering and overhead labor required to remove primary wires and complete the 4-13kV conversions; the contract for manhole rebuild work was awarded higher than estimated; additional labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main that was not known at the time of the prior estimate.	**Section III.A.12.**
RCR-INF-12	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the decrease in the projected cost of the State Street Substation from $38.9 to $19.0 million.	The forecast decrease on the State Street project was driven by the scope change that split the OP scope into a separate project carried out under the Electric Stipulated Base.	No change
RCR-INF-13	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Waverly Substation from $33.8 to $35.0 million.	The forecast increase on the Waverly project was driven by higher carrying costs based on the extended duration stemming from the site plan denial along with additional engineering and licensing and permitting costs related to site plan revisions (see also the response to RCR-INF-2 above).	**Section III.A.15.**
RCR-INF-14	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2021, please explain the increase in the projected cost of the Woodlynne Substation from $18.3 to $21.2 million.	The forecast increase on the Woodlynne project was driven by higher than previously estimated civil construction work, which was slightly offset by lower in-house engineering costs and lower than estimated costs of piles procurement.	**Section III.A.16.**

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-15	With reference to page 22 of the Independent Monitor's Draft Second Quarter 2021 Report, please explain why the outside plant portion of the project has been incorporated into the Company's $100 million electric base component that was originally intended for life cycle station upgrades.	PSE&G informed the IM that discussions it had with BPU Staff and Rate Counsel regarding the mitigation change on the State Street project resulted in the decision to recover the increased cost for the State Street project (then estimated at $16.5 million) in the Company's next rate case as opposed to the ES 2 accelerated recovery. PSE&G's view is that while these increased costs on State Street are prudent and can and should be recovered by way of the accelerated recovery mechanism, it will in this one circumstance defer its request for recovery and credit the additional cost toward the Company's stipulated base requirements for the ES 2 Program.	**Section III.A.13.**
RCR-INF-16	With reference to page 32 of the Independent Monitor's Draft Second Quarter 2021 Report, please describe the proposed outside plant scope of work for the State Street substation proposed by the Company as part of the $100 million electric base.	Related to the change in mitigation method for the State Street project that changed the scope from raise and rebuilt to relocate, the State Street OP scope is comprised of new 4kV OP underground and overhead distribution equipment including manholes and duct banks as required to connect the existing State Street 4kV circuits to the new State Street substation.	**Section III.E.5.**
RCR-INF-17	With reference to page 32 of the Independent Monitor's Draft Second Quarter 2021 Report, please distinguish the difference of the proposed outside plant scope of work for the State Street substation, and the $19.09 million forecasted for the State Street substation as part of the Electric Station Flood Mitigation subprogram.	The State Street scope within the Electric Station Flood Mitigation subprogram contemplates the relocation of the State Street substation from its current site to the new location identified at Cooper Street. The State Street OP scope being executed under the Electric Stipulated Base involves the extensive underground installation required to connect the new 4kV circuits back to the existing 4kV circuits and to maintain the current capacity of these circuits.	**Section III.A.13.**
S-INF-1	**Reference Page 16, Electric Station Flood Mitigation Projects (Clay Street)** What is attributed to the forecasted in-service date for the Clay Street project advancing 50 days?	The advancement of the forecasted in-service date for the Clay Street project experienced during the second quarter of 2021 was driven by the planned start of electrical construction advancing from August 2022 to June 2022.	No change
S-INF-2	**Reference Page 18, Electric Station Flood Mitigation Projects (Hasbrouck Heights)** Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Hasbrouck Heights project increasing by $0.6 million.	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories (Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.1 million • Internal Labor: $0.5 million • Total Change in T&D Surcharge Methodology increase: $0.6 million	**Section III.A.4.**
S-INF-3	**Reference Page 19, Electric Station Flood Mitigation Projects (Leonia)**	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories	**Section III.A.7.**

ID #	Question/Comment	IM Response	Report Changes
	Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Leonia project increasing by $1.2 million.	(Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.6 million • Internal Labor: $0.6 million • Total Change in T&D Surcharge Methodology increase: $1.2 million	
S-INF-4	**Reference Page 21, Electric Station Flood Mitigation Projects (Ridgefield 13kV)** Please provide additional details about the "Change in T&D surcharge methodology" which resulted in the estimated cost of the Ridgefield 13kV project increasing by $1.7 million.	The change in surcharge methodology primarily impacted outside service electrical construction and various internal labor categories (Project Manager, Staff Engineer, Project Engineer, Project Controls Engineer), which resulted in the following estimate change: • Outside Services Electrical Construction: $0.6 million • Internal Labor: $1.1 million • Total Change in T&D Surcharge Methodology increase: $1.7 million	**Section III.A.11.**
S-INF-5	**Reference Page 23, Electric Station Flood Mitigation Projects (Waverly)** Regarding the Waverly project: a. Please provide additional details describing the work included within the approximately $2.8 million in spending during the second quarter of 2021. b. Please confirm that this work will not be affected by the Newark Planning Board's denial of the site plan for the project.	The majority of the actual spend during the second quarter of 2021 was associated with the delivery of the 26kV switchgear in April 2021 ($2.3 million), with the remaining spend in the quarter related to project support costs (Project Management, licensing and permitting) of $0.2 million, engineering costs of $0.2 million, and A/E procured equipment of $0.15 million. The Waverly project site plan was approved by the City in early 2022 with the construction permits received in April 2022.	**Section III.A.15.**
S-INF-6	**Reference Page 24, Table 12 – ES 2 Program Recloser Status as of June 30, 2021** Please provide the total number of 13kV reclosers and 4kV reclosers currently expected to be installed within the Contingency Reconfiguration subprogram.	Recloser installations were completed in early 2022 with a final amount of 932 13kV reclosers and 510 4kV recloser installed during the ES 2 Program.	No change
S-INF-7	**Reference Page 25, Figure 3 – 2021 Recloser Installations as of June 30, 2021** What is attributed to the actual 13kV recloser installations (as of June 30, 2011) exceeding planned 13kV recloser installations for all of 2021?	The change in the number of 13kV reclosers planned stemmed from the decision to identify opportunities to include additional circuits in the subprogram (discussed in Section IV.A.1. of the IM 2021 First Quarter Report and **Section II.A.1.** of this IM 2021 Second Quarter Report). As a result of this review, 365 reclosers on 342 circuits were identified for inclusion in the subprogram, which was comprised of 275 13kV units and 90 4kV units. These were added after the 2021 installation plan was established, which resulted in the actual 13kV recloser installations exceeding the 2021 installation plan.	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-8	**Reference Page 27, Grid Modernization – Communication System** Regarding retrofit recloser installations: a. Please compare the current forecast (2,364 retrofit reclosers) to the originally planned total. b. Please compare the currently forecasted cost of retrofit recloser installations to the originally budgeted cost.	Regarding the retrofit recloser installations: a. PSE&G initially forecasted that 2,601 units would be installed as part of the ES 2 Program, which included 204 substation RTU retrofits. As execution progressed, PSE&G split the tracking of substation RTU retrofits out from the recloser retrofits. The forecasted units also continued periodically to update the forecast based on reviews of current phone line devices, circuit reconfigurations, and removed or replaced units. At completion in December 2021, 2,318 recloser retrofits were installed. b. The budget for the retrofit reclosers was established at $29.6 million while the forecast as of December 2021 was $25.9 million.	
S-INF-9	**Reference Page 27, Table 15 – Fiber Projects by Division** Please confirm that the Waverly fiber project is not expected to be impacted by the site plan denial associated with the Waverly substation project.	The site plan delay on the Waverly substation project resulted in a delay to the Waverly fiber project. The fiber racks and equipment can only be installed after the new control house is built. As such, the Waverly fiber project will be rescheduled to align with the substation control house construction.	**Table 16**
S-INF-10	**Reference Page 28, Table 16 – ES 2 Program Fiber Projects Status as of June 30, 2021** For each fiber project, please compare the forecasted cost to the originally budgeted cost.	The budget and forecasted fiber project cost information has been incorporated into **Table 16**.	**Table 16**
S-INF-11	**Reference Page 32, Electric Stipulated Base** Refer to the statement "The bulk of outside plant higher design and construction standards work is planned to commence in January 2022." a. Please provide additional details about any "outside plant higher design and construction standards" projects that the Company currently expects to include within the "Electric Stipulated Base" spending (excluding the State Street project). b. Please estimate the total spending associated with "outside plant higher design and construction standards" that the Company currently expects to include within "Electric Stipulated Base" spending (excluding the State Street project).	Regarding these requests relating to the Electric Stipulated Base OP higher design and construction standards: a. The OP-Higher Design Standards projects will harden selected 13kV circuits with poor storm performance by changing the construction standard from cross-arm open wire construction to spacer cable construction. In addition to replacing the cross-arms and wires, the scope also provides for replacing poles as needed to meet the higher design standards. b. The original assumption of 1/3 Lifecycle stations and 2/3 OP-Higher Design Standards will be revised by PSE&G based on opportunities to shift Lifecycle stations from Stipulated Base to be funded under the Accelerated Recovery given the final estimates of the 16 electric station flood mitigation stations four previously approved life cycle station projects.	**Section III.E.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-12	**Reference Page 40, Updated Fiber Projects** Regarding the removal of the Howell Street fiber project from the program: a. Please provide additional detail describing the Company's determination that this project would not provide sufficient redundancy and resiliency benefits. b. Please indicate if the Company is considering adding additional fiber projects to replace any removed fiber projects.	The Howell Street substation is located on the same property as the Jersey City Switching Station, which already has a TFI rack that links back to Howell Street. Therefore, PSE&G determined an additional TFI rack at Howell Street was not required for redundancy and resiliency benefits. PSE&G is not anticipating to replace the cancelled fiber projects with new fiber projects.	**Section IV.B.**
4/7/2022 Letter from Rate Counsel	In addition to the above informal questions issued by Rate Counsel, the IM also received a letter on April 7, 2022 from Rate Counsel that provided additional comments on the draft IM 2021 Q2 Report. The nature of the comments in this letter generally summarized the key contents of the draft report and did not include additional specific questions and/or requests, as such the IM is noting receipt of the letter here but has no further response to it.	N/A	N/A
PSE&G-1	Referencing **Table 1**, the total spend to date excludes the Front Street project in the Electric Station Flood Mitigation subprogram.	The IM has corrected the total spend as of the end of the second quarter of 2021 on the Electric Station Flood Mitigation subprogram to $90,603,138, which reflects the inclusion of the Front Street project ($190,915 spend) and still excludes the cancelled Constable Hook project ($133,616 spend). In review of **Table 1**, the IM also identified that the total forecast for the Electric Station Flood Mitigation subprogram included the actual spend associated with the cancelled Constable Hook project, which has now been removed for a revised total forecast of $346,463,155 as of the end of the second quarter of 2021. Similar corrections were also made to **Table 11**.	**Table 1 & Table 11**
PSE&G-2	Referencing the following, "During the second quarter of 2021, retrofit installations continued to ramp up with 685 installations completed during the quarter against a target of 680. In total, 1,432 retrofit reclosers have been installed on the Program through the end of the second quarter out of a total program forecast of 2,364 (which is periodically reviewed and updated)." The number of installations completed during the second quarter of 2021 should be 684 units, not 685 (the total of 1,432 is correct, however).	The IM has corrected the number of retrofit recloser installations completed during the second quarter of 2021 to 684 units.	**Section III.C.**

ID #	Question/Comment	IM Response	Report Changes
PSE&G-3	Referencing the first bullet under “Findings & Observations” for the Grid Modernization – ADMS subprogram, it should state “resource constraints” not “recourse constraints”.	The identified typo has been corrected in this final report.	**Section III.D.**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2021 THIRD QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

AUGUST 24, 2022

Table of Contents

I. Executive Summary 1
II. Program Status 5
A. Key Decisions 5
B. Program Management 6
C. Cost Assignments 6
D. System Performance 11
III. Project Status 17
A. Electric Station Flood Mitigation 17
B. Contingency Reconfiguration 30
C. Grid Modernization – Communication System 33
D. Grid Modernization – ADMS 37
E. Electric Stipulated Base 39
F. Gas M&R Station Upgrades 42

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS
Advanced Metering Interface ..... AMI
Allowance for Funds Used During Construction ..... AFUDC
Architect and Engineer ..... A/E
Board of Public Utilities ..... BPU
Construction Work In Progress ..... CWIP
Costs of Removal ..... COR
Distribution Management System ..... DMS
Distributed Energy Resource Management System ..... DERMS
Distribution Supervisory Control and Data Acquisition ..... DSCADA
Energy Strong 2 ..... ES 2
Gas Metering & Regulating ..... Gas M&R
Independent Monitor ..... IM
Inside Plant ..... IP
Issued for Bid ..... IFB
Issued for Construction ..... IFC
Mobile Work Management System ..... MWMS
New Jersey Department of Environmental Protection ..... NJDEP
New Jersey Sports and Exposition Authority ..... NJSEA
Open Systems International Inc. ..... OSII
Outage Management System ..... OMS
Outside Plant ..... OP
Pipeline and Hazardous Materials Safety Administration ..... PHMSA
Public Service Electric & Gas ..... PSE&G
Purchase Order ..... PO
Record of Decision ..... ROD
Remote Control Unit ..... RCU
Remote Terminal Unit ..... RTU
Risk and Contingency ..... R&C

Supervisory Control and Data Acquisition ..... SCADA

System Average Interruption Duration Index ..... SAIDI

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the third quarter of 2021.

During the third quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with six projects continuing in construction; and Contingency Reconfiguration that continues to advance the installation and commissioning of reclosers largely in alignment with PSE&G's plan. Within the other subprograms, the Grid Modernization – Communication System subprogram placed eight additional fiber installation projects and one additional fiber cutover project in-service, and continued the retrofit recloser installations, with 562 units installed during the third quarter of 2021, bringing the total number of retrofit reclosers installed to 1,994 units out of a current forecast of 2,357 units. The Grid Modernization – ADMS subprogram completed the factory acceptance testing and received and setup server hardware equipment. The Gas M&R subprogram continued construction on the Westampton project, while other stations continued to advance design, submitted site plan/permit packages, and continued other preliminary activities. The Hamilton, Plainfield, and Woodbury projects in the Electric Stipulated Base scope commenced construction during the third quarter of 2021, while construction continued to advance on the Paramus project. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2021

Subprogram	Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	$10,647,819	$101,384,572	$346,555,960	29%	Dec 2024	$389M
Contingency Reconfiguration	$11,715,206	$97,274,191	$145,494,461	67%	Dec 2023	$145M
Grid Modernization – Communications	$6,721,006	$40,110,017	$63,110,594	64%	Dec 2023	$64.3M
Grid Modernization – ADMS	$2,368,648	$23,509,654	$42,722,333	55%	Dec 2022	$42.7M
Electric Stipulated Base	$4,279,681	$13,385,388	$100,000,000	13%	Dec 2023	$100M
Gas M&R Station Upgrades^	$2,950,314	$13,169,538	$95,801,855	14%	Dec 2023	$101M
*Total**	$38,682,675	$288,833,359	$793,685,204	36%	Dec 2024	$842M

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$5,431,127	52%	10/20/2021 (↑)
2. Clay Street	$33,800,000	$3,255,941	10%	12/27/2022 (↓)
3. Front Street^	$27,400,000	$1,261,050	5%	11/6/2023 (↓)
4. Hasbrouck Heights	$22,700,000	$2,091,795	9%	2/7/2023
5. Kingsland	$8,300,000	$531,370	6%	10/4/2023
6. Lakeside Avenue	$47,900,000	$1,045,328	2%	11/8/2023 (↑)
7. Leonia	$26,400,000	$14,399,755	55%	10/10/2022 (↓)
8. Market Street	$29,900,000	$25,293,157	85%	**6/25/2021**
9. Meadow Road	$9,000,000	$899,374	10%	9/22/2023
10. Orange Valley	$20,200,000	$702,848	4%	12/29/2023
11. Ridgefield 13kV	$27,600,000	$14,893,425	54%	11/11/2022 (↓)
12. Ridgefield 4kV	$21,300,000	$20,404,916	96%	**5/16/2021**
13. State Street	$21,400,000	$1,764,732	8%	9/23/2022
14. Toney's Brook	$18,800,000	$1,122,883	6%	4/21/2023
15. Waverly	$35,400,000	$6,339,767	18%	12/18/2024
16. Woodlynne	$19,400,000	$1,947,106	10%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover). **Bold dates indicate the actual in-service date.*

(↑)-Indicates the forecasted in-service date advanced from the prior quarter.

(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

As indicated in **Table 2**, the projects that previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date. Additionally, four of the stations (Leonia, Market Street, Ridgefield 4kV, and State Street) had new estimates approved by the PSE&G's Utility Review Board (URB) in during the third quarter of 2021. **Table 2** also shows that six of the sixteen projects had movement during the third quarter of 2021 in the forecasted in-service date, with two advancing and four slipping. Of these six projects, five of the projects (Academy Street, Clay Street, Front Street, Leonia, and Ridgefield 13kV) had forecasted in-service dates

change by less than two weeks. While the Lakeside Avenue forecasted in-service date advanced 35 days from the status as of the end of the second quarter of 2021. As previously reported, the Waverly final in-service date is currently forecasted for December 2024, unchanged from the prior quarter while the project team continues to work on a new site plan application, which once approved will provide PSE&G with a clearer view of the Waverly schedule, including potential opportunities to advance the in-service date.

The IM has found nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to ensure the ES 2 Program is completed within the defined timeline.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives and has summarized the findings on these areas as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram.
- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. The IM concurrently reviewed the program governance and structure, including the Company's policies and procedures, to understand how the Company intended to execute the projects. As the Program execution advances, the IM evaluates actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. In the initial IM report on the ES 2 Program (the IM 2020 First Quarter Report), a review of the Program governance and the policies and procedures utilized by PSE&G was performed with the IM finding it provided a solid foundation for PSE&G to execute the Program. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.).

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
    - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
    - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
    - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
    - Review and investigation of prior period adjustments and/or corrections to capital accounts.
    - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

  Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied.

Within the Stipulation, it also noted the IM was to review and report "on the impact of the Program on overall system performance during severe weather events." In each quarterly report, the IM reviews any Major Events that occurred in the reporting period, including the system performance metrics provided by PSE&G, and seeks additional information as appropriate to have a more robust view of the system performance. The results of this review are detailed within **Section D**. of the IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On June 7, 2022, a draft IM 2021 Third Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2.*

Subprogram	Record of Decision	IM Comments
		the IM 2021 Second Quarter Report)

During the third quarter of 2021, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

During the third quarter of 2021, PSE&G issued notice to the BPU that it is transferring $7.7 million of funds from the Grid Modernization – Communication System subprogram to the Grid Modernization – ADMS subprogram. The Stipulation provides that PSE&G can immediately reallocate funds amongst the electric subprograms of the ES 2 Program provided that the amount transferred is 5% or less of the overall ES 2 Program electric investment amount. At $7.7 million, this transfer represents approximately 1% of the total $641 million allocated for electric investments in the ES 2 Program. This transfer was supported by the updated estimates completed in the second quarter of 2021 for these two Grid Modernization subprograms (which saw the Grid Modernization – Communication System subprogram estimate decrease by $9.4 million and the Grid Modernization – ADMS subprogram estimate increase by $7.7 million).

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2021, below itemizes the charges to COR for the first three quarters of 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through September 30, 2021.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2021

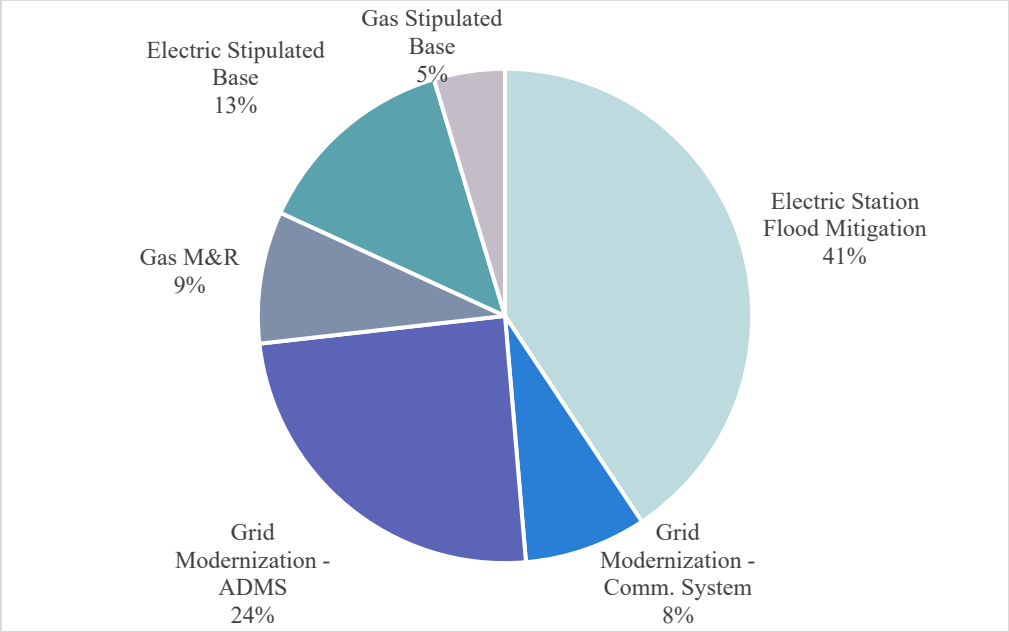
Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)						
Electric Station Flood Mitigation	**$1,464.2**	**$1,141.0**	**$1,129.5**	**$3,734.7**	**$1,021.1**	**$0**	**$4,755.8**
Contingency Reconfiguration	**$811.4**	**$485.2**	**$622.9**	**$1,919.5**	**$2,198.9**	**$431.0**	**$4,549.4**
Grid Modernization – Communications	**$38.6**	**$37.9**	**$37.8**	**$114.3**	**$24.4**	**$0**	**$138.7**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$3.2**	**$0**	**$0**	**$3.2**	**$0**	**$0**	**$3.2**
Gas M&R Station Upgrades	**$63.5**	**$87.6**	**$0**	**$151.1**	**$0**	**$0**	**$151.1**
Gas Stipulated Base	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total	**$2380.9**	**$1,751.7**	**$1,790.2**	**$5,922.8**	**$3,244.4**	**$431.0**	**$9,598.2**

The increase in COR for the third quarter of 2021 from the second quarter reflects, (i) demolition and removal of various 4kV equipment at the Market Street and Ridgefield Electric Station Flood Mitigation elimination projects, and (ii) higher levels of pole fixture, switches, and other equipment removal across virtually all districts in connection with the reclosure projects.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

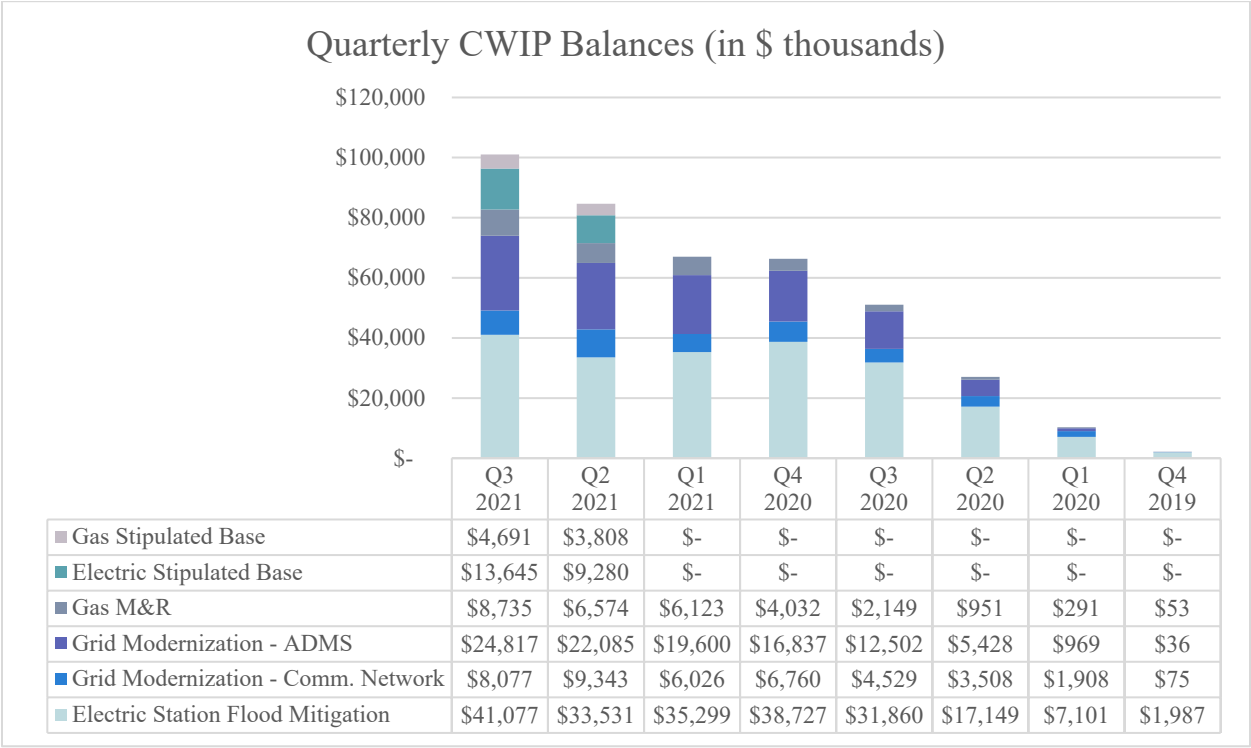
As of September 30, 2021, the Energy Strong CWIP balance was $101.0 million, compared to $84.6 million as of June 30, 2021. The largest components of the September 30, 2021 CWIP were the Leonia ($7.0 million), Waverly ($6.6 million), Westampton ($6.5 million), Ridgefield ($6.4 million) and Academy Street ($5.8 million) substations, as well as the Paramus substation Electric Stipulated Base lifecycle project ($7.1 million), and work associated with the Advanced Distribution and Management System ($24.8 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2021** below.

Figure 1 – ES 2 CWIP as of September 30, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2021, each quarter of 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2021



	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$4,691	$3,808	$-	$-	$-	$-	$-	$-
Electric Stipulated Base	$13,645	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$8,735	$6,574	$6,123	$4,032	$2,149	$951	$291	$53
Grid Modernization - ADMS	$24,817	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. Network	$8,077	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$41,077	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in service totaled $3.8 million during the third quarter of 2021, comprised of fiber projects in the Grid Modernization – Communication Network subprogram. Total ES 2 Program transfers from CWIP have been $38.4 million through September 30, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each Energy Strong subprogram during the third, second and first quarters of 2021, AFUDC for 2021 to date, total AFUDC for the years 2020 and 2019 and total Energy Strong AFUDC accrued to date, is shown below in **Table 5 – ES 2 Program AFUDC as of September 30, 2021**.

Table 5 – ES 2 Program AFUDC as of September 30, 2021

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)						
Electric Station Flood Mitigation	**$581.6**	**$576.7**	**$558.6**	**$1,716.9**	**$936.5**	**$9.9**	**$2,663.3**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$105.2**	**$95.5**	**$59.0**	**$259.7**	**$184.3**	**$0.2**	**$444.2**
Grid Modernization – ADMS	**$363.5**	**$316.9**	**$274.2**	**$954.6**	**$352.7**	**$0.1**	**$1,307.4**
Electric Stipulated Base	**$160.9**	**$80.5**	**$49.6**	**$291.0**	**$44.0**	**$0**	**$335.0**
Gas M&R Station Upgrades (incl. Stip. Base)	**$157.0**	**$107.6**	**$72.2**	**$336.8**	**$70.0**	**$0.2**	**$407.0**
Total	**$1,368.2**	**$1,177.2**	**$1,013.6**	**$3,559.0**	**$1,587.5**	**$10.4**	**$5,156.9**

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2021, based on data as of September 30, 2021, the recalculated weighted average AFUDC accrual rate (6.84%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the third quarter of 2021 at the calculated rate of 6.81%.

AFUDC accrued for Energy Strong projects during the third quarter of 2021 increased over AFUDC accrued during the second quarter of 2021 as the result of increases in total average CWIP balances for almost all subprograms.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2021 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021** are the allocated overhead costs charged to ES 2 subprograms for the first three quarters of 2021, total 2021 year to date, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Electric Station Flood Mitigation	**$2,527**	**$4,352**	**$5,588**	**$12,467**	**$14,023**	**$287**	**$26,776**
Contingency Reconfiguration	**$3,683**	**$4,006**	**$4,215**	**$11,904**	**$17,109**	**$3,415**	**$32,428**
Grid Modernization – Communications	**$2,230**	**$2,506**	**$1,743**	**$6,479**	**$3,625**	**$12**	**$10,116**
Grid Modernization – ADMS	**$125**	**$124**	**$119**	**$368**	**$426**	**$11**	**$805**
Electric Stipulated Base	**$903**	**$287**	**$126**	**$1,316**	**$259**	**$0**	**$1,575**
Gas M&R Station Upgrades (incl. Stip. Base)	**$185**	**$169**	**$131**	**$485**	**$291**	**$15**	**$791**

Subprogram	Q3 2021	Q2 2021	Q1 2021	Year-to-Date 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Total	**$9,653**	**$11,444**	**$11,922**	**$33,019**	**$35,733**	**$3,740**	**$72,491**

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 75%) of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decreases in overhead costs for the third quarter 2021 from the second quarter of 2021 reflect generally lower total subprogram spending levels. Additionally, the IM 2021 Second Quarter Report indicated a total of $11.393 million in allocated overheads during the second quarter of 2021. This figure was updated with revised information provided to the IM after the issuance of that report in which PSE&G identified that the original data provided to the IM contained an error based on when the data was extracted (i.e. the original data was extracted earlier in the month than it should have been). The correct allocated overheads data for the second quarter of 2021 is the $11.444 million shown above in **Table 6**.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2021, there were two Major Events reported in PSE&G's service territory, one concerning a load shedding event in East Orange on September 1-2, 2021, which overlapped with a State of Emergency issued by Governor Murphy on September 1, 2021, due to heavy rains and flooding associated with the remnants of Hurricane Ida. The weather associated with the State of Emergency saw heavy rains fall across PSE&G's service territory over a three-week period. The direct impacts from the remnants of Hurricane Ida were experienced on September 1-2, 2021 and resulted in 105,722 PSE&G customers experiencing service interruptions. During the following weeks through the Major Event period an additional 109,470 PSE&G customers experienced service interruptions. In total, 215,192 PSE&G customers were affected by this Major Event, with 99% of those customers returned to service within 48 hours.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q3 2021 Major Event Performance** below.

Table 7 – Q3 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8012	**0.02574**	**0.02991**
ADA 8024		**0.01838**
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
ALD 8022	0.05448	0.00000
BAO 8014		**0.00164**
BAO 8023		**0.04859**
BEA 8003	0.00238	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
BEA 8010	**0.07397**	**0.17328**
BEF 8014	**0.01387**	**0.10160**
BEN 8016	**0.01934**	**0.14705**
BEN 8021	**0.00143**	**0.01645**
BEN 8022	0.00232	0.00181
BEN 8023	0.18243	0.00000
BLO 4006	**0.00535**	**0.38192**
BRU 8011	0.04127	0.03143

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
BRU 8012	0.01648	0.00240
BRU 8013	**0.00121**	**0.00249**
BUS 8013	0.21323	0.01037
BUS 8015	0.00494	0.00000
CAS 8001	0.02438	0.00084
CED 8013	0.00134	0.00062
CED 8021	0.10724	0.02195
CED 8022	0.05071	0.00061
CET 4012	0.17321	0.09823
CET 4019		**0.06238**
CHA 4013	0.01874	0.00586
CIN 8001	0.12834	0.00237
CIN 8004	0.03186	0.00000
CIN 8005	0.04256	0.00000
CIN 8043	0.18459	0.00262
CLF 8025	0.00177	0.00000
CLK 8014	0.20056	0.00000
CLK 8022	0.06677	0.00673
CLK 8023	**0.00019**	**0.00079**
CLK 8024	0.01526	0.00000
CLK 8032	**0.01489**	**0.07217**
CON 8001		**0.01379**
COR 8015	**0.00123**	**0.01616**
COR 8042	0.05446	0.00000
CRX 8001	0.16798	0.03532
CRX 8009	0.20824	0.00560
CUT 8006	0.59550	0.00073
CUT 8007	0.67234	0.02496
CUT 8041	0.07628	0.00142
DAY 8001	0.15084	0.00440
DAY 8002	0.03617	0.00371
DEA 4001		**0.02289**
DFD 8007	0.06056	0.00496
DFD 8009	**0.03737**	**0.03992**
DFD 8031	0.13025	0.06888
DFD 8041	**0.20440**	**0.42586**
DOR 8012		**0.01725**
DOR 8025		**0.00000**
DVB 8011	0.02010	0.00304
DVB 8013	**0.00455**	**0.00499**
EAO 4019	0.03000	0.01262
EAO 4023	0.08458	0.01803
EAT 8011	0.09890	0.03162
EAT 8013	0.13363	0.00078
EAT 8021	**0.01128**	**0.06889**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
EAT 8022	0.08703	0.00068
EAT 8025		**0.00000**
FAW 8011	0.63063	0.00000
FAW 8014	0.21021	0.00000
FAW 8015	0.06006	0.00000
FAW 8016	0.12332	0.00000
FED 4010	0.01943	0.00289
FED 4022		**0.01411**
FIT 8003	0.01301	0.00000
FRA 8012		**0.00000**
FRA 8021		**0.00000**
GBK 8011	0.27452	0.00068
GBK 8014	0.30784	0.02020
GET 4007	0.06673	0.00000
HAD 4002	**0.03536**	**0.05181**
HAT 8012		**0.00000**
HAT 8021	0.00164	0.00000
HAT 8022	0.30670	0.02147
HAT 8023	0.01869	0.00000
HAT 8027	0.00007	0.00000
HAT 8034		**0.00000**
HAT 8035	0.04291	0.00501
HAW 8032	0.22973	0.00000
HAW 8041	**0.00290**	**0.00888**
HID 8011	0.11110	0.01377
HID 8013	0.02446	0.00369
HID 8044	0.08229	0.01545
HID 8045	0.12747	0.01115
HNC 8021	0.02280	0.00745
HNC 8025	0.49719	0.01143
HOE 8044	0.00039	0.00000
HOM 8003	**0.01571**	**0.02652**
JAC 8012	0.09238	0.03152
JAC 8024	0.25423	0.00265
KEN 4006		**0.00237**
KIL 8023		**0.00026**
KIL 8041	0.02511	0.00000
KIL 8043	0.00194	0.00110
KIL 8044	0.03622	0.00609
KIN 8011		**0.00000**
KIN 8012		**0.00004**
KIN 8022	**0.01206**	**0.01380**
KIN 8023	0.02086	0.00033
KUL 8012	**0.02022**	**0.11076**
KUS 8002	**0.06162**	**0.06911**

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
KUS 8004	0.00500	0.00181
KUS 8042	0.07830	0.02821
KUS 8044	0.01605	0.00000
KUS 8045	0.02505	0.00179
LAF 8026	0.04406	0.01141
LAU 8011	0.30809	0.00382
LAU 8012	0.09474	0.00058
LAU 8021	0.44101	0.01061
LAU 8023	0.82844	0.06185
LAU 8025	**0.02009**	**0.10303**
LAU 8034	0.60195	0.00061
LAW 8015	0.02138	0.00766
LAW 8016	0.14895	0.00054
LCE 8003	0.15926	0.00242
LCE 8005	0.11803	0.00228
LCE 8010	0.05624	0.00090
LCE 8012	0.30622	0.00000
LCE 8032	0.30801	0.00085
LCE 8033	0.42672	0.00000
LCE 8034	0.08300	0.01673
LEO 8005	0.61152	0.01065
LEO 8006	0.07368	0.00191
LEO 8032	0.00287	0.00136
LEO 8034	0.03370	0.00439
LEO 8041	**0.05678**	**0.19273**
LEV 8002	**0.06064**	**0.06469**
LEV 8008	**0.04412**	**0.22621**
LEV 8012	0.25318	0.00790
LEV 8016	0.00021	0.00000
LOC 8014		**0.00000**
LUM 8014	0.29932	0.00336
MAD 8022	0.41375	0.01250
MAI 8013	0.05318	0.04007
MAR 8002	0.04356	0.00225
MAR 8008	0.30277	0.00017
MAR 8010	0.29544	0.00000
MAR 8012	0.05857	0.00003
MAR 8013	0.36502	0.00035
MAR 8016	0.26336	0.00163
MDF 8012	0.58371	0.00116
MDF 8023	0.26488	0.00220
MDF 8024	0.26556	0.00261
MEA 8013	0.04040	0.01311
MEA 8024	0.09438	0.04539
MIN 8013	0.00714	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MIN 8015	0.01242	0.00052
MIN 8026	0.01780	0.00000
MON 8002	0.35076	0.01259
MON 8003	0.27132	0.00639
MOT 8001	0.08290	0.00011
MOT 8002	0.12549	0.03369
MRO 8012	1.08732	0.01453
MRO 8013	0.46710	0.00476
MRO 8022	0.23183	0.00411
MRO 8023	0.19878	0.00363
MRO 8024	0.29163	0.09292
MSD 8001	0.40760	0.00000
NBS 8012	0.09414	0.00000
NBS 8013		**0.91343**
NBS 8021		**0.00000**
NED 8013	0.03270	0.00074
NED 8024		**0.00257**
NED 8025	0.01640	0.01282
NEW 8013	**0.01180**	**0.38418**
NEW 8014	**0.01839**	**0.04522**
NEW 8023	0.02660	0.01247
NEW 8025	0.00343	0.00187
NEW 8032		**0.00063**
NEW 8034	0.10522	0.02843
NEW 8041	**0.00280**	**0.00362**
NEW 8044	0.00273	0.00101
NIN 4001	0.05314	0.04194
NOT 8011		**0.00000**
NOT 8023	0.00214	0.00032
NRB 8014	0.03116	0.00000
NRB 8022		**0.00000**
NRP 4004		**0.01437**
NRP 4010		**0.04988**
OAK 4004	0.05636	0.00000
ORA 4002	0.07591	0.00126
PAT 4003		**0.00721**
PEH 8004		**0.00387**
PEH 8015		**0.03327**
PEH 8025	0.00149	0.00000
PEK 8018	0.08524	0.00000
PEK 8021	0.00069	0.00010
PEK 8023	0.05457	0.00088
PEK 8026	**0.04523**	**0.18109**
PEK 8035	0.28036	0.00550
PIE 8013	0.02355	0.08797

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
PIE 8015	0.05606	0.00000
PLI 8004	**0.01320**	**0.03537**
PLI 8007	0.05542	0.00000
PLI 8008	0.19552	0.00115
POH 8012		**0.00000**
POH 8013	0.00898	0.00428
POH 8015	0.12765	0.00000
POH 8022	0.01503	0.00000
POL 4001		**0.00248**
RFL 8011	**0.00742**	**0.02311**
RFL 8021		**0.00007**
RFL 8023	**0.00885**	**0.02943**
RFL 8032	0.12446	0.00056
RFL 8034	0.04180	0.01396
RGW 4004	0.00776	0.00647
RIV 8006	0.00765	0.00604
RUN 8001		**0.00032**
RUN 8004	0.29484	0.00485
RVR 8022		**0.00000**
SAD 8032		**0.00000**
SAD 8043	**0.00775**	**0.02839**
SAD 8044	**0.00192**	**0.00594**
SDH 8021		**0.00154**
SDH 8026	0.01685	0.00155
SDH 8034		**0.00000**
SMV 8011	**0.00774**	**0.01043**
SMV 8013		**0.00293**
SMV 8021		**0.24553**
SMV 8024		**0.00000**
SMV 8025	0.01386	0.00575
SOH 8022	0.16946	0.00000
SOO 4011	0.62019	0.00232
SOO 4012	0.14426	0.03350
SOP 4007		**0.01162**
SPF 8012	0.78752	0.04433
SPF 8016		**0.00000**
SPF 8023	0.01271	0.00188
SPF 8024	0.00263	0.00000
SPF 8025	0.09408	0.00000
SUN 8011	0.05952	0.01374
SUN 8013		**0.00000**
SUN 8021		**0.00000**
SUN 8034	0.02298	0.00204
SUN 8035	0.03902	0.00000
SUN 8044		**0.01258**
SWT 8001		**0.01151**
TNY 4002	**0.05690**	**0.13013**
TNY 4003	**0.03940**	**0.45732**
TUR 8004	0.00879	0.00019
VIL 8001	0.24055	0.00000
WAD 8011	0.08512	0.02281
WAD 8013	0.12231	0.02871
WAN 8014		**0.04307**
WAN 8015		**0.00009**
WAN 8025	0.66194	0.00000
WAV 4018	**0.02277**	**0.03127**
WEW 8021	0.21824	0.02186
WEW 8025	0.00255	0.00115
WEW 8031		**0.00088**
WEW 8033	0.03506	0.02681
WEW 8041		**0.00957**
WEW 8042	0.01304	0.00000
WEW 8044	0.07375	0.00735
WFL 8012	0.02690	0.02304
WFL 8032	**0.11140**	**0.27363**
WFL 8034	0.04228	0.00082
WOR 8011	0.02748	0.00579
WOR 8013	**0.13969**	**0.37336**
WOR 8022	**0.00042**	**0.00517**
WOR 8025	0.03185	0.00000
WYN 4003	0.31855	0.00312
YRD 8014	0.05063	0.02029
YRD 8024	0.08273	0.00820

**-System Average Interruption Duration Index (SAIDI) calculations are in minutes; bold values indicate circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. As indicated above, there were 269 circuits impacted by this

Major Event 177 of which had a current Major Event SAIDI better than the 5-year Major Event SAIDI average, while an additional 51 circuits had no Major Event outage within the 5-year comparison window, leaving 41 circuits that both had a prior Major Event outage within the past 5-years and had worse performance during this Major Event.

Additional information on the 15 worse performing circuits from this Major Event is provided below in **Table 8 – Q3 2021 Major Event Additional Information on Selected Circuits.** Note that some of these circuits had more than one incident during the Major Event, resulting in a total of 57 incidents from these 15 circuits, and that some show zero customers impacted, which reflects the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair).

Table 8 – Q3 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BEA 8010	0.07397	0.17328	1,644	257
BEA 8010	0.07397	0.17328	19	175
BEF 8014	0.01387	0.10160	873	230
BEF 8014	0.01387	0.10160	873	56
BEN 8016	0.01934	0.14705	410	247
BEN 8016	0.01934	0.14705	1,053	247
BLO 4006	0.00535	0.38192	1,505	567
BLO 4006	0.00535	0.38192	60	179
BLO 4006	0.00535	0.38192	63	69
BLO 4006	0.00535	0.38192	403	174
DFD 8041	0.20440	0.42586	729	303
DFD 8041	0.20440	0.42586	331	303
DFD 8041	0.20440	0.42586	373	364
DFD 8041	0.20440	0.42586	1	3,661
DFD 8041	0.20440	0.42586	44	2,220
DFD 8041	0.20440	0.42586	105	3,877
DFD 8041	0.20440	0.42586	20	4,057
KUL 8012	0.02022	0.11076	878	310
LAU 8025	0.02009	0.10303	62	164
LAU 8025	0.02009	0.10303	1,394	155
LAU 8025	0.02009	0.10303	663	18
LAU 8025	0.02009	0.10303	37	325
LAU 8025	0.02009	0.10303	30	100
LEO 8041	0.05678	0.19273	387	885
LEO 8041	0.05678	0.19273	0	1,042
LEO 8041	0.05678	0.19273	8	1,041
LEO 8041	0.05678	0.19273	20	1,042
LEO 8041	0.05678	0.19273	1,324	43
LEO 8041	0.05678	0.19273	1,324	34
LEV 8008	0.04412	0.22621	2,603	183
LEV 8008	0.04412	0.22621	82	970
NEW 8013	0.01180	0.38418	32	778
NEW 8013	0.01180	0.38418	1,131	258
NEW 8013	0.01180	0.38418	894	258
NEW 8013	0.01180	0.38418	478	830
PEK 8026	0.04523	0.18109	1,556	286

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
PEK 8026	0.04523	0.18109	0	53
TNY 4002	0.05690	0.13013	0	182
TNY 4002	0.05690	0.13013	1,380	115
TNY 4002	0.05690	0.13013	39	183
TNY 4002	0.05690	0.13013	451	115
TNY 4002	0.05690	0.13013	17	178
TNY 4002	0.05690	0.13013	52	223
TNY 4002	0.05690	0.13013	6	178
TNY 4002	0.05690	0.13013	599	86
TNY 4002	0.05690	0.13013	775	45
TNY 4003	0.03940	0.45732	0	653
TNY 4003	0.03940	0.45732	647	652
TNY 4003	0.03940	0.45732	1,013	652
TNY 4003	0.03940	0.45732	1,660	25
WFL 8032	0.11140	0.27363	2	2,169
WFL 8032	0.11140	0.27363	1	2,169
WFL 8032	0.11140	0.27363	11	2,169
WFL 8032	0.11140	0.27363	135	4,756
WOR 8013	0.13969	0.37336	1,780	385
WOR 8013	0.13969	0.37336	1,350	172
WOR 8013	0.13969	0.37336	0	62
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. Additionally, the circuits in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers). For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Three of the circuits that had more severe outages than the five-year average were DFD 8041, LEO 8041, and WFL 8032, each of which had an outage involving tree impacts, with additional circuit-specific information as follows:

- DFD 8041: a tornado touched down in the area and resulted in the primary line down from wind/tree impacts.
- LEO 8041: a tree brought down all three phases, resulting in no circuit operation.
- WFL 8032: large tree impact resulted in multiple phases down in addition to flooding in the area.

Beyond the circuit-level performance, this Major Event and the flooding associated with resulted in water entering eight of the substations that were raised and rebuilt as part of the original Energy Strong

Program,[1] however, due to the storm hardening at those stations none was interrupted by these flooding events.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the third quarter of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2021**.

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
	Sep. 2021		KO		C						IS			CO						
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
	Sep. 2021			KO							C				IS					CO (Q2)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Sep. 2021								KO				C						IS	CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Sep. 2021		KO									C					IS		CO	
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Sep. 2021			KO											C				IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Sep. 2021						KO							C					IS	CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Sep. 2021			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Sep. 2021			KO					C/OS				CO							
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Sep. 2021			KO											C			IS		CO (Q2)

December 31, 2023 - ES 2 Program End Date

[1] The eight substations upgraded during ES 1 that experienced water intrusions included: Belmont, Cranford, Ewing, Hoboken, New Milford, Port Street, Rahway, and Somerville.

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Sep. 2021					KO									C					IS (Q1); CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Sep. 2021			KO	C										IS			CO		
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Sep. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Sep. 2021		KO						C					IS						CO (Q1)
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Sep. 2021			KO										C			IS			CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Sep. 2021			KO			C													IS (Q4); CO (Q2 2025)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Sep. 2021		KO												C				IS	CO (Q2)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout

-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).

***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**

^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the third quarter of 2021 is provided below **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road;

Activity	Total # of Projects	Specific Projects
		Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	17*	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	7	Academy Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly
In-Service	2	Market Street; Ridgefield 4kV

**-Three of the listed projects (Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 17 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or outside plant construction.*

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2021** summarizes the planned activities for each project during the fourth quarter of 2021, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q4 2021

Station	Upcoming Activities for Q4 2021	Carryover Activities from Q3 2021
1. Academy Street	• Place switchgear in-service on 1st circuit	• Continued engineering and construction
2. Clay Street	• Civil and electrical drawings (phase 2) Issued for Construction (IFC) • Electrical construction out for bid	• Continued engineering
3. Front Street	• Switchgear Purchase Order (PO) issued • License and permitting package issued • Site plan submitted for approval	• Continued engineering
4. Hasbrouck Heights	• Switchgear and capacitor bank delivered	• Continued engineering
5. Kingsland	• License and permitting package issued • Civil and electrical drawings IFC	• Commence license and permitting design • Continued engineering
6. Lakeside Avenue	• Site plan submittal • Vendor drawings received (final switchgear arrangement)	• Submit site plan application • Vendor drawings received (final switchgear arrangement)
7. Leonia	• 13kV switchgear #1 in-service	• Continued engineering and construction • Start commissioning of 13kV switchgear #1

Station	Upcoming Activities for Q4 2021	Carryover Activities from Q3 2021
8. Market Street	• Electrical demolition complete	• Start civil and electrical demolition
9. Meadow Road	• Receive New Jersey Department of Environmental Protection (NJDEP) permit	• Continued engineering
10. Orange Valley	• City council approval of site plan amendment • Vendor drawings received (final switchgear arrangement)	• Continued engineering
11. Ridgefield 13kV	• Commissioning and in-servicing switchgear #2	• Continued construction
12. Ridgefield 4kV	• Complete civil demolition	• Continued demolition
13. State Street	• Switchgear delivered • Start electrical construction	• 70% estimate completed • Switchgear delivered
14. Toney's Brook	• Start preliminary civil manhole/conduit work • Controls drawings IFC	• Continued engineering
15. Waverly	• Vendor drawings received (final switchgear controls) • Civil and electrical drawings IFC • New Site Plan meeting	• Site plan meeting requested • Continued engineering
16. Woodlynne	• Construction permits received	• Continued engineering

The current project estimates, including base and R&C amounts, is shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2021**. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the third quarter of 2021.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$9,012,316	$5,431,127	52%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$30,735,399	$3,255,941	10%
3. Front Street*	Study	$23,000,000	$4,400,000	$27,400,000	$25,889,200	$1,261,050	5%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,480,201	$2,091,795	9%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,540	$531,370	6%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$1,045,328	2%
7. Leonia	Definitive	$24,900,000	$1,500,000	$26,400,000	$24,851,796	$14,399,755	55%
8. Market Street	Definitive	$29,100,000	$800,000	$29,900,000	$29,032,028	$25,293,157	85%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,441,372	$899,374	10%
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$14,765,212	$702,848	4%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$25,987,975	$14,893,425	54%
12. Ridgefield 4kV	Definitive	$20,800,000	$500,000	$21,300,000	$20,716,895	$20,404,916	96%
13. State Street	Conceptual	$19,100,000	$2,300,000	$21,400,000	$19,040,411	$1,764,732	8%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$1,122,883	6%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$35,319,007	$6,339,767	18%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,255,000	$1,947,106	10%
Subprogram Total*		**$332,200,000**	**$47,800,000**	**$380,000,000**	**$346,555,960**	**$101,384,573**	**27%**

**-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*
***-The Subprogram Total presented in this Table 12 excludes the $5.3 million previously estimated for the cancelled Constable Hook project and excludes an additional $3.7 million approved by the URB for the subprogram and currently allocated as a placeholder. The currently approved URB funding for the subprogram includes both these amounts, resulting in a total subprogram estimate of $389.0 million. The cancelled Constable Hook project and the subprogram placeholder are also not included in the current $346.6 million subprogram forecast.*

Findings & Observations

- Six of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the third quarter of 2021, with two advancing and four slipping. Of these six projects, five of the projects (Academy Street, Clay Street, Front Street, Leonia, and Ridgefield 13kV) had forecasted in-service dates change by less than two weeks. The Lakeside Avenue forecasted in-service date advanced 35 days from the status as of the end of the second quarter of 2021.

- Following the Market Street and Ridgefield 4kV projects being placed in-service during the second quarter of 2021, the next project forecasted to go in-service is the Academy Street project in October 2021.

- Four projects had new estimates approved by the URB during the third quarter of 2021, including the Leonia project advancing to the Definitive level with a new estimate of $26.4 million (decreasing $1.1 from the prior estimate); the Market Street project submitting a revised Definitive level estimate with a new estimate of $29.9 million (increasing $3.0 million from the prior estimate); the Ridgefield 4kV project submitted a revised Definitive level estimate with a

new estimate of $21.3 million (increasing $1.8 million from the prior estimate); and the State Street project advancing to the Conceptual level with a new estimate of $21.4 million (decreasing $1.0 million from the prior estimate).

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of the third quarter of 2021, the Waverly project continues to show a final in-service date in December 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from December 2022 (26kV switchgear) to December 2024 (Transformer #3). PSE&G has informed the IM that the project team has every intention of improving the in-service dates and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the third quarter of 2021, $217,396 was spent on the Academy Street project compared to a forecast of approximately $600,000, which brought the total spend to approximately $5.4 million. The variance in spend during the third quarter of 2021 was driven by the focus on commissioning the Fairmount 69kV project before bringing the Academy Street project in-service. Despite that delay to commissioning activities, the forecasted in-service date for the Academy Street project advanced by five days from the prior quarter to October 20, 2021.

The primary activity conducted during the third quarter of 2021 on the Academy Street project was the continued advancement of construction activities. Construction, which started in July 2020 for non-permit work on Academy Street, advanced 13% during the third quarter to reach 88% complete inside plant (100% complete outside plant), while the total project is reported at 90% complete as of the end of the third quarter of 2021.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					*Forecast*	
$150,398	$4,224,550	$378,939	$405,843	$271,396	$1,046,595	$2,534,594

Actuals to Date	Estimate	% of Actuals to Estimate
$5,431,127	$10,500,000	52%

2. Clay Street

During the third quarter of 2021, $1,099,440 was spent on the Clay Street project compared to a forecast of approximately $1.1 million, which brought the total spend to approximately $3.3 million. The forecasted in-service date for the Clay Street project as of the end of the third quarter of 2021 slipped eight days from the end of the second quarter to December 27, 2022.

The primary activities on the Clay Street project during the third quarter of 2021 included the IFC release of control drawings and civil construction work going out for bid.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$116,409	$879,339	$565,030	$595,723	$1,099,440	$4,968,997	$22,510,461

Actuals to Date	Estimate	% of Actuals to Estimate
$3,255,941	$33,800,000	10%

3. Front Street

During the third quarter of 2021, $1,070,135 was spent on the Front Street project compared to a forecast of approximately $431,000, which brought total spend to approximately $1.3 million. The variance in spend during the third quarter of 2021 was driven by a change in the payment terms for the temporary switchgear from full payment at delivery to partial milestones. The forecasted in-service date for the Front Street project as of the end of the third quarter of 2021 slipped four days from the end of the second quarter to November 6, 2023.

The primary activities on the Front Street project during the third quarter of 2021 included the issuance of the PO for the temporary switchgear, completion of the permit compliance matrix, and approval of the scope document.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$0	$0	$190,915	$1,070,135	$1,074,477	$23,553,673

Actuals to Date	Estimate	% of Actuals to Estimate
$1,261,050	$27,400,000	5%

4. Hasbrouck Heights

During the third quarter of 2021, $71,649 was spent on the Hasbrouck Heights project compared to a forecast of approximately $910,000, which brought the total spend to approximately $2.1 million. The variance in spend during the third quarter of 2021 was driven by inclement weather and limited resource availability that delayed the start of Outside Plant (OP) Division work. The forecasted in-service date for the Hasbrouck Heights project continues to remain February 7, 2023, which is unchanged from the previous quarter.

Notable activities completed during the third quarter of 2021 included the contingency plan control drawings IFC and the start of OP manhole enlargement work.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$149,848	$1,129,934	$550,795	$189,748	$71,469	$5,370,203	$13,018,203

Actuals to Date	Estimate	% of Actuals to Estimate
$2,091,795	$22,700,000	9%

5. Kingsland

During the third quarter of 2021, $150,084 was spent on the Kingsland project compared to a forecast of approximately $243,000, which brought the total spend to $531,370. The forecasted in-service date for the Kingsland project continues to remain October 4, 2023, which is unchanged from the previous quarter.

During the third quarter of 2021, the Kingsland project commenced detailed design and license and permitting design work.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$104,112	$209,667	$30,621	$36,886	$150,084	$202,265	$5,684,906

Actuals to Date	Estimate	% of Actuals to Estimate
$531,370	$8,300,000	6%

6. Lakeside Avenue

During the third quarter of 2021, $89,151 was spent on the Lakeside Avenue project compared to a forecast of approximately $105,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the third quarter of 2021 advanced 35 days from the prior quarter to November 8, 2023.

Notable activities completed during the third quarter of 2021 included the submittal of the site plan application, receipt of vendor drawings (final switchgear arrangement), and the commencement of detailed engineering.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$148,943	$453,994	$178,973	$174,268	$89,151	$216,131	$38,094,820

Actuals to Date	Estimate	% of Actuals to Estimate
$1,045,328	$47,900,000	2%

7. Leonia

During the third quarter of 2021, $1,365,412 was spent on the Leonia project compared to a forecast of approximately $1.4million, which brought the total spend to approximately $14.4 million. The forecasted in-service date for the Leonia project as of the end of the third quarter of 2021 slipped 10 days from the prior quarter to October 10, 2022.

Notable activities completed during the third quarter of 2021 included the commissioning of the 13kV switchgear #1. The Leonia project also advanced to the Definitive level estimate, which was approved by the URB in July 2021. This Definitive level estimate resulted in the total estimate for the project being reduced to $26.4 million from $27.5 million (at the Conceptual level estimate). The reduction in the current estimate was the result of:

- Revised estimate for Division underground work: -$0.4 million;
- Increase in construction costs: $0.3 million; and,
- Reduction in R&C based on the current risk profile for the project: -$1.0 million.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,365,412	$1,642,466	$8,809,575

Actuals to Date	Estimate	% of Actuals to Estimate
$14,399,755	$26,400,000	55%

8. Market Street

During the third quarter of 2021, $1,779,029 was spent on the Market Street project compared to a forecast of approximately $2.0 million, which brought the total spend to approximately $25.3 million. Notable activities conducted during the third quarter of 2021 included the commencement of electrical demolition at the station, which was placed out of service on June 25, 2021 following the completion of the 4kV to 13kV conversion work.

The Market Street project also had a revised Definitive level estimate approved by the URB in August 2021, which resulted in the total estimate increasing by $3.0 million from the previous Definitive level estimate. The increase was driven by:

- Additional OP overhead and restoration work along with associated material and surcharges based on the complexity of the work and the field conditions: $2.8 million, which was comprised of:
    - Unknown OP field conditions: condition of poles, conductors, transformers, and service wires along with space constraints for equipment operation required increased labor and

material to resolve. In addition, hazardous soils required use of backhoes, which in turn required additional road closures/traffic safety control;

- Cutover procedures: During the procedures for the 13kV conversions, the City mandated additional police around the work areas to ensure public safety and to minimize traffic detours. While construction activities were ongoing, the system being upgraded needed to remain in service and operations to continue to serve customers, which resulted in a higher that estimated level of effort and materials to complete this work safely and reliably; and,
- Traffic control procedures: Included in the conditions of permit approval, County and City officials required additional police presence and other traffic control contractor labor to safeguard work areas and mitigate traffic disruptions.

- Higher than estimated traffic control as per city/county requirements: $1.1 million.
- Reduction in R&C based on the current risk profile for the project: -$0.9 million.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					*Forecast*	
$251,193	$16,079,601	$4,035,880	$3,147,454	$1,779,029	$3,020,923	$717,949

Actuals to Date	Estimate	% of Actuals to Estimate
$25,293,157	$29,900,000	85%

9. Meadow Road

During the third quarter of 2021, $113,271 was spent on the Meadow Road project compared to a forecast of $69,000, which brought the total spend to approximately $900,000. Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on the Meadow Road project this quarter as the bulk of this project's activities planned for 2022-2023. The forecasted in-service date for the Meadow Road project as of the end of the third quarter of 2021 remained unchanged from the prior quarter at September 22, 2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$63,128	$535,081	$117,672	$70,220	$113,271	$88,000	$6,453,998

Actuals to Date	Estimate	% of Actuals to Estimate
$899,374	$9,000,000	10%

10. Orange Valley

During the third quarter of 2021, $108,806 was spent on the Orange Valley project compared to a forecast of approximately $75,000, which bought the total spend to approximately $703,000. Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on

the Orange Valley project this quarter as the bulk of this project's activities planned for 2022-2023. The forecasted in-service date for the Orange Valley project as of the end of the third quarter of 2021 remained unchanged from the project quarter at December 29, 2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$77,029	$362,895	$7,291	$146,827	$108,807	$68,426	$13,993,938

Actuals to Date	Estimate	% of Actuals to Estimate
$702,848	$20,200,000	4%

11. Ridgefield 13kV

During the third quarter of 2021, $1,573,500 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $14.9 million. The variance in spend during the third quarter of 2021 was driven by manhole and duct bank work planned for September that was postponed due to an obstruction by the concrete slab in the way of the manhole modification that was not part of the original design, and thus was not identified during the design phase of the project. The forecasted in-service date for the Ridgefield 13kV project as of the end of the third quarter of 2021 slipped three days from the prior quarter to November 11, 2022.

Notable activities completed during the third quarter of 2021 included the start of electrical construction and the setting of the first permanent 13kV switchgear. Construction at Ridgefield 13kV advanced to 70% complete inside plant as of the end of the second quarter of 2021, compared to 58% complete at the end of the prior quarter, with the total project at a reported 70% completion.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$205,982	$6,232,692	$3,215,967	$3,665,283	$1,573,500	$2,760,022	$8,334,528

Actuals to Date	Estimate	% of Actuals to Estimate
$14,893,425	$27,600,000	54%

12. Ridgefield 4kV

During the third quarter of 2021, $1,653,764 was spent on the Ridgefield 4kV project compared to a forecast of approximately $1.9 million, which brought the total spend to approximately $20.4 million. The variance in spend this quarter was driven by Division accruals released while the invoice was paid against an incorrect workorder (corrected via journal entry). The project was placed in-service on May 16, 2021.

The primary activities performed during the third quarter of 2021 included the commencement of station demolition. The total project is reported at 99% complete as of the end of the second quarter of 2021, up from 85% complete as of the end of the prior quarter.

The Ridgefield 4kV project also had a revised Definitive level estimate approved by the URB in July 2021, which resulted in the total estimate increasing by $1.8 million from the previous Definitive level estimate. The increase was driven by:

- Division manhole rebuild work awarded higher than estimate: $0.3 million;
- Additional Division labor and material required to rebuild several secondary buses and reroute two underground circuits around an existing gas main: $0.8 million;
- Additional engineering and overhead hours required to remove primary wires to complete 4-13kV conversions (involving aerial cable removal omitted from prior estimates): $1.2 million; and,
- Reduction in R&C based on the current risk profile of the project: -$0.5 million.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals					*Forecast*	
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,653,764	$251,980	$60,000

Actuals to Date	Estimate	% of Actuals to Estimate
$20,404,916	$21,300,000	96%

13. State Street

During the third quarter of 2021, $571,099 was spent on the State Street project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $1.8 million. The variance in spend during the quarter was driven by the switchgear delivery shifting from September as forecasted to October. The forecasted in-service date for the State Street project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at September 23, 2022. The sequencing of the IP and OP scopes of the State Street project always planned on the IP scope being completed prior to the OP scope, with that continued sequencing there is no advancement in the in-service date for this project following the split of the State Street OP scope to an Electric Stipulated Base project.

Notable activities performed on State Street during the third quarter of 2021 included the commencement of civil construction. The State Street project also advanced to the Conceptual level estimate, which was approved by the URB in August 2021. This Conceptual level estimate resulted in the total estimate for the project being reduced to $21.4 million from $22.4 million (at the revised Study level estimate). The reduction in the current estimate was the result of:

- Cost of removal scope award lower than estimated: -$0.5 million;
- Lower carrying cost: -$0.4 million;
- Capacitor banks award higher than estimated: $0.2 million;
- Revised Division electrical construction estimate: $0.5 million;
- Reduction in R&C based on the project's current risk profile: -$0.8 million

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$77,590	$662,148	$237,415	$216,479	$571,099	$6,885,880	$10,389,799

Actuals to Date	Estimate	% of Actuals to Estimate
$1,764,732	$21,400,000	8%

14. Toney's Brook

During the third quarter of 2021, $159,132 was spent on the Toney's Brook project compared to a forecast of approximately $186,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Toney's Brook project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at April 21, 2023.

Notable activities achieved during the third quarter of 2021 included the approval of state and municipal permits.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$211,940	$373,096	$88,947	$289,769	$159,132	$437,135	$14,694,311

Actuals to Date	Estimate	% of Actuals to Estimate
$1,122,883	$18,800,000	6%

15. Waverly

During the third quarter of 2021, $277,739 was spent on the Waverly project compared to a forecast of approximately $437,000, which brought the total spend to approximately $6.3 million. The variance in second quarter spend was largely driven an engineering milestone that shifted from September to October and work delayed in September due to lack of resources in the Metro Division. The forecasted in-service date for the Waverly project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 18, 2024 as the project awaits resolution of its site plan application.

As reported in the IM 2021 First Quarter Report, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which requires the project team to prepare a new site plan application. The comments received on the original site plan from the Newark Planning Board generally focused on the outward appearance of the substation. The revised site plan was submitted to the Newark Planning Board in early September 2021 with the site plan approval expected to be granted in a December 2021 meeting. The revised site plan incorporated feedback received from community meetings and from discussions with the Director of Arts and Culture for the City of Newark and the Newark Arts Council. The result is redesigned street facing frontages to the substation that includes a fence with brick finish (giving a wall-like appearance) and locations for artwork to be placed, two entrance gates with matching color schemes, portions of the isolation walls that were visible were redesigned to match the brick finishes on the street facing fences, and landscaping around the sidewalk area outside the substation was also added.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2025
Actuals					*Forecast*	
$103,748	$2,460,815	$659,572	$2,837,893	$277,739	$930,920	$28,048,320

Actuals to Date	Estimate	% of Actuals to Estimate
$6,339,767	$35,400,000	18%

16. Woodlynne

During the third quarter of 2021, $428,009 was spent on the Woodlynne project compared to a forecast of approximately $414,000, which brought the total spend to approximately $1.9 million. The forecasted in-service date for the Woodlynne project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at October 10, 2023.

Preliminary design work continued to progress during the third quarter of 2021, with minimal other activities conducted on the Woodlynne project this quarter as the bulk of this project's activities planned for 2022-2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$110,982	$993,298	$282,187	$132,630	$428,009	$1,248,185	$18,059,709

Actuals to Date	Estimate	% of Actuals to Estimate
$1,947,106	$19,400,000	10%

B. Contingency Reconfiguration

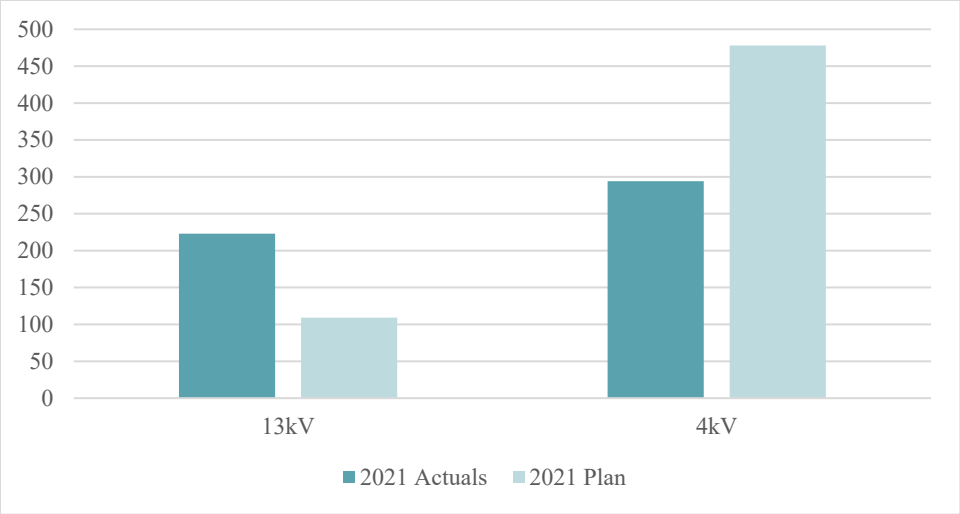
During the third quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 161 installed during the quarter and 173 commissioned. **Table 13 – ES 2 Program Recloser Status as of September 30, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of September 30, 2021** compares the installed reclosers as of the end of the third quarter of 2021 against PSE&G's 2021 installation plan.[2]

[2] Note that as discussed in the IM 2021 First Quarter Report (Section IV.A.1.) and the IM 2021 Second Quarter Report (Section II.A.1.), the number of reclosers identified the Contingency Reconfiguration subprogram was updated after the 2021 installation plan was established, which resulted in a net reduction of the 4kV reclosers planned for the subprogram and a net increase of the 13kV reclosers planned for the subprogram.

Table 13 – ES 2 Program Recloser Status as of September 30, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q3 Qty.	*2021 Total*	*Program Total*	*Q3 Qty.*	*2021 Total*	*Program Total*	*Q3 Qty.*	*2021 Total*	*Program Total*
13kV	74	220	919	81	223	884	91	227	871
4kV	60	248	502	80	294	451	82	294	449
Total	134	468	1,421	161	517	1,335	173	519	1,320

Figure 3 – 2021 Recloser Installations as of September 30, 2021



As shown in **Table 13** and **Figure 3**, PSE&G continued to maintain progress during the third quarter of 2021 and stayed on track for the 2021. As discussed in prior IM reports, there was an identified resource constraints within the Metro Division that prompted PSE&G to engage a contractor to perform the pole settings from the recloser scope, which commenced early in the second quarter of 2021, to reduce schedule impacts including avoiding other potential resource constraints if the recloser installations were to slip further into 2022 and overlap with the Fuse Saver scope.

The Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021.[3] In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing

[3] In the second quarter of 2021, PSE&G decided to install the remaining 34 Fuse Savers in its inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. These installations were completed across the second and third quarters of 2021.

additional orders. Because of this, the full Fuse Saver scope is no longer anticipated to commence in 2021.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2021**. This table also shows the forecasted final in-service dates as of the end of the second quarter of 2021 to show movement to the forecast as of the end of the third quarter of 2021.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2021

Scope & Division		Q2 2021 Forecasted Completion Date	Q3 2021 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022
	Metro	1/31/2022	1/31/2022
	Palisades	10/31/2021	12/31/2021
	Southern	1/31/2022	1/31/2022
Fuse Savers	Central	12/30/2023	9/30/2023
	Metro	12/30/2023	10/31/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	10/31/2023

As shown in **Table 14**, the forecasted final in-service dates for three of the four Division's Fuse Saver program advanced two to three months based on a reduction of the number of units to be installed, with the final number of units still under evaluation by PSE&G as it seeks the optimal mix of locations (maximizing customers served against locations requiring pole replacements) based on ongoing field assessments to accommodate the higher costs observed in the pilot program and the fixed budget for this scope of work. While the only change to the recloser scope of work was the Palisades Division slipping two months, which was driven by engineering delays on the remaining approved units.

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2021 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of September 30, 2021**.

Table 15 – Contingency Reconfiguration Costs as of September 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$2,116,213	$22,304,495	$25,105,143	89%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$3,926,036	$21,523,190	$24,376,440	88%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$1,991,442	$22,327,156	$22,913,508	97%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$2,742,523	$26,303,462	$28,940,957	91%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$255,092	$1,538,195	$12,022,135	13%
	Metro	$7,557	$561,915	$216,511	$89,860	$144,511	$1,020,354	$10,958,702	9%
	Palisades	$7,468	$522,454	$133,552	$63,808	$276,182	$1,003,464	$8,409,356	12%
	Southern	$9,792	$859,014	$65,018	$56,845	$263,207	$1,253,876	$12,768,220	10%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$11,715,206**	**$97,274,191**	**$145,494,461**	**67%**

Findings & Observations:

- PSE&G continued to maintain progress on the recloser installations during the third quarter of 2021 and stayed on track for the 2021, assisted by the ongoing engagement of a pole setting contractor to alleviate resource constraints in the Metro Division.
- The forecasted completion of the recloser scope of this subprogram remained unchanged from the prior quarter for three of the four Divisions, while the Palisades Division forecasted completion slipped two months based on the progress of engineering. For the Fuse Savers, while the Palisades Division completion remained unchanged, the other three Divisions advanced their forecasted completion date two to three months reflecting a reduction in the number of planned units.
- The Contingency Reconfiguration subprogram forecast was reduced approximately $1.6 million to a total forecast of $145.5 million as of the end of the third quarter of 2021 from the prior quarter. This was largely driven by reductions to the planned number of fuse savers anticipated for the subprogram.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

As reported in the IM 2020 Second Quarter Report, PSE&G made the strategic decision to focus on new recloser installations and has delayed the ramp-up in retrofit installations from August 2020 to January 2021 due to resource constraints. During the third quarter of 2021, retrofit installations continued to advance with 562 installations completed during the quarter against a target of 573. In total, 1,994 retrofit reclosers have been installed on the Program through the end of the third quarter out of a total program forecast of 2,357 (which is periodically reviewed and updated). The remaining units are expected to be completed by the end of 2021.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with two of 41 installation projects since removed due to the scheduled elimination of the targeted substations. The list of identified fiber installation and cutover projects is presented in **Table 16 – Fiber Projects by Division as of September 30, 2021**.

Table 16 – Fiber Projects by Division as of September 30, 2021

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-

Division	Fiber Installation	Fiber Cutover
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street; Howell Street*	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***39 projects***	***12 projects***
*******-As discussed in Section IV.B. of the IM 2021 Second Quarter Report, the Howell Street project was identified for removal from the subprogram as the result of a PSE&G review of the project conducted in the fourth quarter of 2021.*		

During the third quarter of 2021, eight additional fiber installation projects (Bordentown, Central Ave., Chauncey Street, First Street, Harrison, Norfolk Street, Princeton, and South Orange) and one fiber cutover project (Henry Street) were placed in-service. **Table 17 – Q3 Fiber Projects Budget vs. Actual Cost** shows the original budget of these projects against the actual costs as of the end of the third quarter of 2021.

Table 17 – Q3 Fiber Projects Budget vs. Actual Cost

Project	Budget	Actual (as of Q3 2021)	Variance
Bordentown*	$0	$528,017	$528,017
Central Ave.	$480,000	$110,548	($369,452)
Chauncey Street	$840,000	$849,852	$9,852
First Street	$300,000	$570,579	$270,579
Harrison	$300,000	$563,245	$263,245
Norfolk Street	$300,000	$183,294	($116,706)
Princeton	$300,000	$1,070,766	$770,766
South Orange	$390,000	$302,912	($87,088)
Henry Street (cutover)**	$50,000	$206,685	$156,685

**-Not on initial project list and therefore no initial budget, added after review of projects performed (See the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report)*
***-Cutover projects were budgeted by Division (each cutover project is budgeted at the Division budget divided by number of stations in the scope for that Division).*

With the eight additional fiber installation projects and one additional fiber cutover project placed in-service during the third quarter of 2021, it brought the total projects in-service as of the end of the third quarter of 2021 to 17 for the fiber installation projects and nine for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the third quarter of 2021 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2021

Project Name	Q3 2021 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Inside Plant (IP) IFC issued

Project Name	Q3 2021 Status
Bordentown	*In-Service (Q3 2021)*
Carteret	OP IFC issued
Central Ave	*In-Service (Q3 2021)*
Central HQ	Received approved railroad crossing agreement
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	Preliminary engineering
East Orange	*In-Service (Q1 2021)*
Edison	OP construction mobilized
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	Continued construction
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering
Hadley Rd HQ	IP IFC issued
Haledon	IP civil construction complete; OP construction complete
Harrison	*In-Service (Q3 2021)*
Howell Street	Preliminary engineering*
Irvington	IP IFC issued; OP construction complete; IP construction mobilized
Irvington Sub HQ	IP, OP IFC issued; OP construction complete; IP construction mobilized
Keasbey	Preliminary engineering
Lehigh Avenue	Preliminary engineering
Mechanic Street	Preliminary engineering
Metro HQ	*In-Service (Q1 2021)*
Montclair	IP IFC issued
Morgan Street	OP construction mobilized
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	Continued construction
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	IP IFC issued; IP civil construction complete
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	IP civil construction completed; OP IFC issued
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*

Project Name	Q3 2021 Status
Fairview	Completion dependent upon Fort Lee fiber installation project
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	Completion dependent upon West New York fiber installation project
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 204 units	9 cutovers completed
**-As indicated in the IM 2021 Second Quarter Report, the Howell Street fiber project was identified for removal from the subprogram during the fourth quarter of 2021.*	

The Grid Modernization – Communication System subprogram costs through the end of the third quarter of 2021 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021**.

Table 19 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals							
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$715,214	$3,694,388	$6,817,605	54%
	Metro	$0	$818,620	$436,089	$683,893	$733,376	$2,671,977	$5,485,018	49%
	Palisades	$0	$825,174	$754,869	$965,416	$888,467	$3,433,927	$6,173,947	56%
	Southern	$0	$929,058	$956,444	$1,005,852	$1,082,897	$3,974,252	$7,314,919	54%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$1,007,245	$5,573,779	$9,178,564	61%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$1,198,777	$4,238,981	$7,885,388	54%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$605,647	$3,627,579	$6,022,939	60%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$591,125	$3,180,714	$3,366,815	94%
	Cutovers*	$0	$876,502	$323,458	$86,115	$109,880	$1,395,955	$2,967,868	47%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$124,015	$6,833,252	$7,897,530	87%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	($335,637)	$1,485,213	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,175**	**$6,721,006**	**$40,110,017**	**$63,110,594**	**64%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Findings & Observations:

- During the third quarter of 2021, retrofit installations continued to advance following the ramp-up earlier in 2021 with 562 installations completed during the quarter against a target of 573. In total, 1,994 retrofit reclosers have been installed on the Program through the end of the third quarter of

2021 out of a total program forecast of 2,357 (which continues to be periodically reviewed and updated).

- Eight additional fiber installation projects and one fiber cutover project were placed in-service during the third quarter of 2021, bringing the total number of projects in-service to 17 fiber installation projects and nine fiber cutover projects.

- The forecast for the Grid Modernization – Communication system subprogram increased approximately $2.7 million as of the end of the third quarter of 2021 from the prior quarter. The bulk of this increase ($2.6 million) was in the fiber scope, which was driven by the updated fiber and communication requirements based on the current status of the PSE&G substations and Operations Centers selected for this scope, including IP contractor quotes higher than estimated and costs of outsourcing the overhead scope on selected projects to augment Division resources . Overall, the subprogram forecast of $63.1 million remains below the adjusted Stipulation budget amount of $64.3 million (following the $7.7 million transfer of funds to the Grid Modernization – ADMS subprogram).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS), the Outage Management System (OMS), and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the third quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.

- Q3 2021 Activities:

    - Resolved factory acceptance testing action items list and compiled factory acceptance testing results.

    - Conducted advanced metering interface (AMI) use case compilation discussion and completed AMI use case demo from Open Systems International Inc. (OSII).

- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.

- Q3 2021 Activities:
    - Conducted additional AMI interface workshops and initial mobile security design sessions.
    - Completed database installation for outage data warehouse.
    - Onboarded mobile work management system (MWMS) interface team and conducted MWMS design workshops.
- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/2/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q3 2021 Activities:
    - Reviewed testing gaps, selected testing tools, and created testing strategy.
    - Received all ADMS equipment shipments.
- Forecasted In-Service Date as of the end of the third quarter of 2021: 12/10/2021.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2021 are presented in **Table 20 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2021**.

Table 20 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,368,648	$3,564,757	$15,647,923

Actuals to Date	Forecast	% of Actuals to Forecast
$23,509,654	$42,722,333	55%

Findings & Observations:

- The server equipment received during the third quarter of 2021 required approximately one month to set up the equipment in alignment with PSE&G's security standards. The PSE&G team was able to implement the network segmentation, although the setting up and connecting of the server hardware consumed the bulk of the float in the schedule. However, the forecasted in-service date for the subprogram remains at December 2022 as of the end of the third quarter of 2021.
- The Grid Modernization – ADMS forecast remained nearly unchanged as of the end of the third quarter of 2021 from the second quarter of 2021, with an approximate $10,000 forecast increase to the $42.7 million subprogram.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[4] The bulk of outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 21 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2021**.

Table 21 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$2,083,445	11%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$6,940,343	34%	11/11/2022 (↑)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$2,478,976	11%	10/17/2022 (↑)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$1,811,330	10%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$71,294	0%	3/2/2023 (↑)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 21**, of the five life cycle station upgrade projects, the Paramus, Plainfield, and State Street OP projects each saw a slight advancement to their forecasted in-service dates, advancing four, three, and 13 days, respectively. Given the relatively small magnitude of these changes, the IM has not performed additional schedule analyses on these projects but will continue to monitor for potential trends. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- The primary activities during the third quarter of 2021 continued to center around advancing the engineering, permitting, and procurement processes for the life cycle station upgrade projects.

[4] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Construction also commenced on the Hamilton, Plainfield, and Woodbury projects during the third quarter of 2021, and continued on Paramus, which started construction in the second quarter of 2021.

- There was minor movement to the forecasted in-service dates for the Paramus, Plainfield, and State Street OP projects during the third quarter of 2021, with each advancing between 3-13 days from the prior quarter's forecast. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022 while the State Street OP project is forecasted for completion in the first quarter of 2023.

1. Hamilton

During the third quarter of 2021, $1,083,435 was spent on the Hamilton project against a forecast of approximately $1.3 million. This brought total spend on the project to approximately $2.1 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included:

- Municipal permits received;
- Controls drawings IFC; and,
- Electrical construction out for bid.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$362,372	$236,783	$400,855	$1,083,435	$1,723,783	$12,477,686

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,083,446	$18,200,000	$16,284,915	11%

2. Paramus

During the third quarter of 2021, $1,564,308 was spent on the Paramus project against a forecast of approximately $1.7 million. This brought total spend on the project to approximately $6.9 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included:

- Site plan approval received;
- 4kV contingency feeder rows delivered;
- Civil and electrical drawings IFC; and,
- Civil and electrical construction out for bid.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below. The current forecast of approximately $20.5 million represents an increase to the forecast of approximately $1.5 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated construction and material/equipment awards.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$840,200	$358,846	$4,176,989	$1,564,308	$1,023,572	$12,533,678

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$6,940,343	$20,200,000	$20,497,593	34%

3. Plainfield

During the third quarter of 2021, $1,214,476 was spent on the Plainfield project against a forecast of approximately $2.2 million. The variance between actual and forecasted spend was driven by lower than estimated hours to complete the work performed in the quarter and some work shifting to October. This brought total spend on the project to approximately $2.5 million through the end of the third quarter of 2021. The current forecast of approximately $22.1 million represents an increase to the forecast of approximately $2.4 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated construction and additional steel quantities with a higher steel price than was initially estimated.

Notable activities conducted during the third quarter of 2021 included:

- Municipal permits approved; and,
- OP construction commenced.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals					*Forecast*	
$0	$682,325	$214,632	$367,543	$1,214,476	$1,966,058	$17,640,676

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,478,976	$22,600,000	$22,085,710	11%

4. Woodbury

During the third quarter of 2021, $363,802 was spent on the Woodbury project against a forecast of approximately $380,000. This brought the total spend on the project to approximately $1.8 million through the end of the third quarter of 2021.

Notable activities conducted during the third quarter of 2021 included the issuance of civil and electrical construction POs.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$551,165	$540,138	$356,225	$363,802	$480,591	$15,571,232

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,811,330	$18,700,000	$17,863,153	10%

5. State Street (Outside Plant)

During the third quarter of 2021, $53,660 was spent on the State Street (OP) project against a forecast of approximately $42,000. This brought the total spend on the project to approximately $71,000.

Notable activities conducted during the third quarter of 2021 included the signoff of the project's scope document. The forecasted in-service date for the State Street (OP) project, currently forecasted for March 2, 2023, reflects the continued planned sequencing of this project, which will be completed after the State Street project within Electric Station Flood Mitigation subprogram is completed.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$0	$0	$0	$17,633	$53,660	$729,292	$18,912,003

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$71,294	$22,700,000	$19,712,589	0%

F. Gas M&R Station Upgrades

Through the end of the third quarter of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the pre-construction activities for the five projects not in construction, while the Westampton project continued its construction activities towards a fourth quarter of 2021 in-service date. **Table 22 – ES 2 Gas M&R Summary Status as of September 30, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 22 – ES 2 Gas M&R Summary Status as of September 30, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$2,082,756	7%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$1,493,901	5%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$1,318,297	8%	Dec 2022
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$794,330	7%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$921,080	7%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$6,559,174	66%	Oct 2021 (↑)
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$13,169,538**	**12%**	**Dec 2023**

**-Included in the Stipulated Base.*

(↑)-Indicates the forecasted in-service date advanced from the prior quarter.

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*							

The in-service dates for the Gas M&R projects as of the end of the third quarter of 2021 remained static from the status at the end of the prior quarter except for the Westampton project, which advanced from a forecasted in-service date of December 16, 2021 to October 22, 2021 based on the progression of the construction work.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and preparing construction bid packages. The Westampton project, which commenced construction in April 2021 and is forecasted to be complete by the end of 2021, advanced ahead of schedule.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time and/or on budget. During the third quarter of 2021 there were no updates to the Gas M&R project estimates and the forecast in-service dates remained unchanged from the prior quarter for the majority of the projects, except the Westampton project which advanced approximately two months based on the progress of the works.

1. Camden

During the third quarter of 2021, $413,548 was spent on the Camden project compared to a forecast of approximately $357,000, which brought the total spend to approximately $2.1 million. The current forecast of approximately $26.3 million represents an increase to the forecast of approximately $2.0 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by material costs coming in higher than what was initially estimated.

The forecasted in-service date for the Camden project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Camden project during the third quarter of 2021 included:

- Received approved resolution from the City of Camden;
- Ordered long lead materials/equipment; and,
- Received issued for bid (IFB) construction package.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$13,326	$859,350	$505,693	$290,839	$413,548	$1,321,924	$22,868,132

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$2,082,756	$29,300,000	$26,272,811	7%

2. Central

During the third quarter of 2021, $311,084 was spent on the Central project compared to a forecast of approximately $264,000, which brought the total spend to approximately $1.5 million. The current forecast of approximately $25.7 million represents an increase to the forecast of approximately $1.8 million from the status as of the end of the second quarter of 2021. This forecast increase was driven by higher than estimated material costs and additional design efforts required to address the complexity of the station and to incorporate modifications to meet the site plan approval requirements.

The forecasted in-service date for the Central project as of the end of the third quarter of 2021 remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Central project during the third quarter of 2021 included:

- Received construction bids and held bid clarification meetings;
- Received site plan approval from the Township of Edison;
- Submitted Title V air permit; and,
- Building PO issued to vendor.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$6,869	$670,582	$315,258	$190,109	$311,084	$6,765,527	$17,469,616

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,493,901	$29,000,000	$25,729,044	5%

3. East Rutherford

During the third quarter of 2021, $189,737 was spent on the East Rutherford project compared to a forecast of approximately $210,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the East Rutherford project remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the East Rutherford project during the third quarter of 2021 included:

- Issued Pipeline and Hazardous Materials Safety Administration (PHMSA) notification as required for upcoming construction; and,
- Completed final license and permit package and submitted permit application to the New Jersey Sports and Exposition Authority (NJSEA) and Bergen County.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$9,010	$521,865	$337,573	$260,112	$189,737	$1,030,830	$11,450,873

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$1,318,297	$16,500,000	$13,800,000	7%

4. Mount Laurel

During the third quarter of 2021, $121,165 was spent on the Mount Laurel project compared to a forecast of approximately $182,000, which brought the total spend to approximately $794,000. The forecasted in-service date for the Mount Laurel project remains unchanged from the prior quarter at December 30, 2022.

Notable activities completed on the Mount Laurel project during the third quarter of 2021 included:

- Received soil erosion and sediment control permit;
- Submitted site package and received conditional approval from the Burlington County Planning Board; and,
- Received IFB drawing package for review.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$5,965	$362,167	$155,351	$149,682	$121,165	$510,606	$8,095,064

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$794,330	$11,400,000	$9,400,000	7%

5. Paramus

During the third quarter of 2021, $92,239 was spent on the Paramus project compared to a forecast of approximately $131,000, which brought the total spend to approximately $921,000. The forecasted in-service date for the Paramus project remains unchanged from the prior quarter at December 29, 2023.

Notable activities completed on the Paramus project during the third quarter of 2021 included the receipt of the preliminary drawing package for review.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$8,842	$462,452	$227,854	$129,694	$92,239	$114,443	$10,464,477

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$921,080	$13,700,000	$11,500,000	7%

6. Westampton

During the third quarter of 2021, $1,822,542 was spent on the Westampton project compared to a forecast of approximately $1.7 million, which brought the total spend to approximately $6.6 million. The forecasted in-service date for the Westampton project advanced 55 days from the status at the end of the second quarter of 2021 to October 22, 2021, which was the result of the progress of the construction efforts on the project.

Construction on the Westampton project, which commenced in April 2021, was reported at 85% complete as of September 2021. Other notable activities completed on the Westampton project during the third quarter of 2021 included:

- Completed demolition of existing regulator building;
- Completed header piping and regulator piping installation; and,
- Completed new regulator building foundation and started building erection.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals					*Forecast*	
$8,395	$1,032,670	$478,072	$3,217,496	$1,822,542	$2,191,211	$349,615

Actuals to Date	Estimate	Current Forecast	% of Actuals to Estimate
$6,559,174	$10,000,000	$9,100,000	66%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

AUGUST 24, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q3 2021 Report, Page 1** Regarding the Grid Modernization – Communication System subprogram, what is attributed to the reduction in forecasted retrofit recloser installations from 2,449 units (See Q2 2021 Report, Page 1) to 2,357 units?	PSE&G periodically revises the number of forecasted retrofit recloser units to be installed under the ES 2 Program based on reviews of current phone line devices, circuit reconfigurations, and previously removed or replaced units. As a result of the updated status of these factors, the number of planned units is subject to being reduced.	No change
S-INF-2	**Reference Q3 2021 Report, Page 2, Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2021** Regarding the Electric Station Flood Mitigation project "State Street": a. Why has the forecasted in-service date of this project not advanced from September 2022 after the outside plant portion of this project was added to Electric Stipulated Base? b. Why is the outside plant portion of this project not expected to be placed in-service until March 2023 (See Q3 2021 Report, Page 35, Table 20) given that the Electric Station Flood Mitigation portion of this project has been projected to be placed in-service in September 2022 since before the outside plant portion was removed?	When the IP and OP scopes of the State Street project were planned to be executed as one project, the IP portion (which remains in the Electric Station Flood Mitigation subprogram) was forecasted to be placed in-service in September 2022, while the OP portion (now executed under Electric Stipulated Base) had been forecasted to be executed following the completion of the IP scope with a then forecasted in-service date of April 2023. This sequencing is effectively unchanged following the split of the IP and OP scopes on this project, though since that split the forecasted in-service date for the State Street OP project has advanced to March 2023.	**Section III.A.13. & Section III.E.5.**
S-INF-3	**Reference Q3 2021 Report, Pages 8-9, Table 6 – ES 2 Program Overhead Allocations as of September 30, 2021** What is attributed to Q2 2021 overhead allocations increasing from $11,393,000 in the IM's previous report (See Q2 2021 Report, Page 11) to $11,444,000 in this report?	The change in overhead allocations for the second quarter of 2021 from $11.393 million as reported in the IM 2021 Second Quarter Report to $11.444 million in this IM 2021 Third Quarter Report was the result of an error in the original second quarter data provided to the IM by PSE&G. PSE&G informed the IM this error was caused by a difference in the date/time the SAP data was extracted for each report, with the original second quarter data downloaded earlier in the month than typical. The correct amount for the second quarter of 2021 is the $11.444 million shown in **Table 6** of this report.	**Section II.C.4.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-4	**Reference Q3 2021 Report, Page 26, Electric Station Flood Mitigation Projects (Waverly)** a. Please provide additional details about the modifications incorporated into the Waverly substation project and their associated costs which led to the Newark Planning Board approving the site plan in early 2022 (as indicated in the response to S-INF-5 in the IM's Q2 2021 Report). b. Please indicate if the Waverly substation project is currently expected to be placed in service within the Energy Strong II program window.	Regarding the requests concerning the Waverly project: a. When the initial site plan was rejected, the comments received from the Newark Planning Board generally focused on the outward appearance of the substation. The revised site plan incorporated feedback received from community meetings and from discussions with the Director of Arts and Culture for the City of Newark and the Newark Arts Council. The result was redesigned street facing frontages to the substation that included a fence with brick finish (giving a wall-like appearance) and locations for artwork to be placed, two entrance gates with matching color schemes, portions of the isolation walls that were visible were also redesigned to match the brick finishes on the street facing fences, and landscaping around the sidewalk area outside the substation. b. As of April 2022 (the most recent data available to the IM at the time of this report), the final in-service date had improved to February 27, 2024, which still remains outside of the ES 2 program window. This relates to the transformer #3 in-service date, while the 4kV switchgear and transformers #1-2 are forecasted to be in-service in October 2023.	**Section III.A.15.**
S-INF-5	**Reference Q3 2021 Report, Page 28, Contingency Reconfiguration Subprogram** Regarding the Contingency Reconfiguration subprogram, please compare the total number of reclosers currently forecasted to be installed to originally budgeted totals.	At the time of the ES 2 filing, PSE&G estimated 1,816 reclosers to be installed in the Program. With the completion of the recloser scope in January 2022, a total of 1,467 reclosers were installed. The revision to the number of units planned in the subprogram was also discussed in the IM 2021 First and Second Quarter Reports (Section IV.A.1 and Section II.A.1, respectively). Additionally, as of the initial subprogram forecast received by the IM (April 2020, when the IM engagement began), the recloser scope of the Contingency Reconfiguration subprogram had a forecast of $107,976,302, while the final costs of the recloser scope was $101,920,298.	No change
S-INF-6	**Reference Q3 2021 Report, Page 29, Contingency Reconfiguration Subprogram** With respect to the Contingency Reconfiguration subprogram, it is noted that "the forecasted final in-service dates for three of the four Division's Fuse Saver program advanced two to three months based on a reduction of the number of units to be installed."	Regarding the Fuse Saver scope of work: a. PSE&G is still evaluating the number of Fuse Saver units to be removed from the Program through on ongoing field assessments and a prioritization based on customers served and locations not requirement a pole replacement. PSE&G expects this to be an iterative process with the final number of	**Section III.B.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>a. Please provide the total number of Fuse Saver units removed from the program for each division.
b. Please provide additional details describing the Company's rationale for reducing the number of Fuse Saver units.</td><td>units determined by the average cost per unit based on the most optimal mix of locations with and without pole replacements given the fixed budget.
b. The reduction in the planned number of Fuse Saver units is the result of the higher cost per unit observed in the pilot program.</td><td></td></tr>
<tr><td>S-INF-7</td><td><u>Reference Q3 2021 Report, Page 30, Grid Modernization – Communication System Subprogram</u>
Regarding the Grid Modernization – Communication System subprogram, it is stated that "During the third quarter of 2021, eight additional fiber installation projects (Bordentown, Central Ave., Chauncey Street, First Street, Harrison, Norfolk Street, Princeton, and South Orange) and one fiber cutover project (Henry Street) were placed in-service." For each of these projects placed in-service during Q3 2021, please compare the final cost to the budgeted cost.</td><td>For the projects placed in-service during the third quarter of 2021, the budgeted vs. actual costs are shown below:
<table>
<tr><th>Project</th><th>Budget</th><th>Actual (as of Q3 2021)</th></tr>
<tr><td>Bordentown*</td><td>$0</td><td>$528,017</td></tr>
<tr><td>Central Ave.</td><td>$480,000</td><td>$110,548</td></tr>
<tr><td>Chauncey Street</td><td>$840,000</td><td>$849,852</td></tr>
<tr><td>First Street</td><td>$300,000</td><td>$570,579</td></tr>
<tr><td>Harrison</td><td>$300,000</td><td>$563,245</td></tr>
<tr><td>Norfolk Street</td><td>$300,000</td><td>$183,294</td></tr>
<tr><td>Princeton</td><td>$300,000</td><td>$1,070,766</td></tr>
<tr><td>South Orange</td><td>$390,000</td><td>$302,912</td></tr>
<tr><td>Henry Street (cutover)**</td><td>$50,000</td><td>$206,685</td></tr>
</table>
*-Not on initial project list and therefore no initial budget, added after review of projects performed (See the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report)
**-Cutover projects were budgeted by Division (each cutover project is budgeted at the Division budget divided by number of stations in the scope for that Division).</td><td>Section III.C. (Table 17)</td></tr>
<tr><td>S-INF-8</td><td><u>Reference Q3 2021 Report, Page 31, Table 17 – ES 2 Program Fiber Projects Status as of September 30, 2021</u>
With respect to the fiber installation project "Bergen Point", please discuss if this project will remain used and useful following the upcoming retirement of the Bergen Point substation.</td><td>PSE&G confirmed to the IM that the Bergen Point fiber project will remain used and useful through the schedule retirement of the Bergen Point substation in 2026. PSE&G intends to replace the substation with a 69kV/13kV station and the fiber connectivity design at this new station will determine if any portion of the current Bergen Point fiber installation will remain used and useful.</td><td>No change</td></tr>
<tr><td>S-INF-9</td><td><u>Reference Q3 2021 Report, Page 31, Table 17 – ES 2 Program Fiber Projects Status as of September 30, 2021</u>
With respect to the fiber installation project "Howell Street", please reconcile why the project's Q3 2021 status is listed as "preliminary engineering" when the IM's previous report indicated that this project was removed from the program (<u>See</u> Q2 2021 Report, Page 42).</td><td>As indicated in the IM 2021 Second Quarter Report, the decision to remove the Howell Street fiber project was made during the fourth quarter of 2021. The IM's approach is to have the main body of the quarterly reports generally reflect the Program status as of the end of the reporting quarter (while providing notable post-quarter information in a separate section of the report). Thus, Table 18 (renumbered after</td><td>Section III.C. (Table 18)</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		the new Table 17 was added in response to S-INF-7 above) shows the fiber project status as of September 30, 2021.	
S-INF-10	**Reference Q3 2021 Report, Page 32, Table 18 – ES 2 Grid Modernization – Communication System Costs as of September 30, 2021** Regarding the Grid Modernization – Communication System subprogram, what is the currently anticipated in-service date of the Wireless Network project?	The wireless network scope was placed in-service as of December 16, 2021.	No change
S-INF-11	**Reference Q3 2021 Report, Pages 32-33, Grid Modernization – Communication System Subprogram** Refer to the statement "The forecast for the Grid Modernization – Communication system subprogram increased approximately $2.7 million as of the end of the third quarter of 2021 from the prior quarter. The bulk of this increase ($2.6 million) was in the fiber scope, which was driven by the updated fiber and communication requirements based on the current status of the PSE&G substations and Operations Centers." Please provide additional details about the updated fiber and communication requirements.	This forecast increase was driven by higher overall cost estimates resulting from changes in communication requirements, costs of outsourcing overhead scope on some projects (needed to augment Division resources), and IP contractor quotes higher than estimated. Updated communication requirements contained within the new cost estimates reflect the adjustment of the project list discussed in the ROD reviewed in Section IV.A. of the IM 2020 Third Quarter Report.	**Section III.C.**
S-INF-12	**Reference Q3 2021 Report, Page 36, Electric Stipulated Base (Paramus Project)** Regarding the Paramus life cycle substation project, what factors are attributed to the forecasted cost ($20,497,593) exceeding the base cost plus risk and contingency ($20,200,000)?	The higher forecast on the Paramus life cycle substation project is driven by higher than estimated construction and material/equipment awards.	**Section III.E.2.**
S-INF-13	**Reference Q3 2021 Report, Pages 36-37, Electric Stipulated Base (Plainfield Substation Project)** With respect to the Plainfield life cycle substation project, what is attributed to the forecasted cost increasing from $19,645,315 (See Q2 2021 Report, Page 37) to $22,085,710?	The higher forecast on the Plainfield life cycle substation project is driven by higher than estimated construction awards and additional steel with a higher steel price than estimated.	**Section III.E.3.**
S-INF-14	**Reference Q3 2021 Report, Page 39, Gas M&R Station Upgrades (Camden M&R Station Project)** Regarding the Camden M&R station project, what is attributed to the forecasted cost increasing from $24,300,000 (See Q2 2021 Report, Page 39) to $26,272,811?	The approximately $2.0 million increase in the Camden M&R station project forecast from the second to third quarter of 2021 was driven by material costs higher than estimated.	**Section III.F.1.**
S-INF-15	**Reference Q3 2021 Report, Page 39, Gas M&R Station Upgrades (Central M&R Station Project)**	The approximately $1.8 million increase in the Central M&R station project forecast from the second to third quarter of 2021 was driven by:	**Section III.F.2.**

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Central M&R station project, what is attributed to the forecasted cost increasing from $23,900,000 (See Q2 2021 Report, Pages 39-40) to $25,729,044?	• $0.4 million attributed to: additional design efforts required due to the complexity of the station and drawing modifications to meet the township site plan approval requirements. • $1.5 million attributed to: material costs higher than estimated. • $0.1 million reduction attributed to: reduced licensing and permitting costs based on actuals to date and an updated estimate of remaining work.	
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Academy Street substation including actual in-service date or anticipated in-service date.	The Academy Street substation project was placed in-service on October 19, 2021, when the switchgear was placed in-service.	No change
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Market Street substation including actual in-service date or anticipated in-service date.	The Market Street substation elimination project was placed in-service as of June 25, 2021, when all the 4kV circuits were converted to 13kV.	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of the Ridgefield 4kV substation including actual in-service date or anticipated in-service date.	The Ridgefield 4kV substation elimination project was placed in-service as of May 16, 2021, when all the 4kV circuits were converted to 13kV.	No change
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the status of anticipated in-service date of substation work expected to be completed in 2022.	As shown in **Table 2**, the Clay Street, Leonia, Ridgefield 13kV, and State Street projects were forecasted as of the end of the third quarter of 2021 to be placed in-service during 2022. As of the end of June 2022 (most current information presently available to the IM), the status of the forecasted in-service dates for these projects is as follows: • Clay Street: slipped to January 2023 due to delays in receiving the above grade structures and electrical construction permits. • Leonia: forecasted for December 2022. • Ridgefield 13kV: forecasted for December 2022. • State Street: forecasted for December 2022.	No change
RCR-IM-5	With reference to page 3 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update regarding the Waverly substation site plan approval process.	The site plan received conditional approval by the Newark Planning Board in December 2021 with memorialization of the compliance resolution in January 2022.	No change
RCR-IM-6	With reference to page 3 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the delayed site	PSE&G updated the estimate for the Waverly substation project in January 2022. In this updated estimate, the base estimate increased	No change

ID #	Question/Comment	IM Response	Report Changes
	plan for the Waverly substation will increase projected costs for the project.	from $29.4 million to $36.2 million, which included $2.6 million related to additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	
RCR-IM-7	With reference to Table 8 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide additional details regarding the outages identified for circuits DFD 8041, LEO 8041, and WFL 8032 including the circumstances leading to the outage and whether something unique about the outage caused it to be much more severe than the reported 5-year baseline level.	These circuits all saw severe impacts from the Major Event, in particular tree impacts. Specific information on each circuit is provided as follows: • DFD 8041: a tornado touched down in the area and resulted in the primary line down from wind/tree impacts. • LEO 8041: a tree brought down all three phases, resulting in no circuit operation. • WFL 8032: large tree impact resulted in multiple phases down in addition to flooding in the area.	**Section II.D.1.**
RCR-IM-8	With reference to page 14 of the Independent Monitor's Draft Third Quarter 2021 Report, please identify the eight substations that experienced water intrusion.	The eight substations that experienced water intrusions during the Major Event included: Belmont, Cranford, Ewing, Hoboken, New Milford, Port Street, Rahway, and Somerville.	**Section II.D.1.**
RCR-IM-9	With reference to page 23 of the Independent Monitor's Draft Third Quarter 2021 Report, please describe the additional outside plant work that resulted in the $2.8 million increase.	The additional OP overhead and restoration work that drove the $2.8 million increase to the Market Street project was driven by unknown OP field conditions, more complicated cutover and traffic control procedures than previously anticipated, and overall quantity of labor and material higher than previously estimated to complete the project scope. Additional details on these cost drivers are as follows: • Unknown OP field conditions: condition of poles, conductors, transformers, and service wires along with space constraints for equipment operation required increased labor and material to resolve. In addition, hazardous soils required use of backhoes, which in turn required additional road closures/traffic safety control. • Cutover procedures: During the procedures for the 13kV conversions, the City mandated additional police around the work areas to ensure public safety and to minimize traffic detours. While construction activities were ongoing, the system being upgraded needed to remain in service and operations to continue to serve customers, which resulted in a higher that estimated level of effort and materials to complete this work safely and reliably. • Traffic control procedures: Included in the conditions of permit approval, County and City officials required additional	**Section III.A.8.**

ID #	Question/Comment	IM Response	Report Changes
		police presence and other traffic control contractor labor to safeguard work areas and mitigate traffic disruptions.	
RCR-IM-10	With reference to page 23 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the Company is experiencing higher than estimated traffic control requirements for other projects and if the Company is factoring increased traffic control requirements for future projects. If not, please explain why not.	Generally, PSE&G has not experienced higher than estimated traffic control requirements across the ES 2 Program, however higher traffic costs have been experienced on certain individual projects (e.g. Market Street) based on additional requirements required by the local municipality. PSE&G develops its traffic control estimates based on the amount of street work expected to be executed and the permit requirements for each location.	No change
RCR-IM-11	With reference to page 24 of the Independent Monitor's Draft Third Quarter 2021 Report, please explain if the concrete slab impacting the Ridgefield 13 kV substation was identified during the design phase of the project. If not, please explain why not	The concrete slab that obstructed the manhole/duct bank work was not identified during the design phase of the project. The manhole modifications were not required by the original design and therefore were not part of the original scope.	**Section III.A.11.**
RCR-IM-12	With reference to page 25 of the Independent Monitor's Draft Third Quarter 2021 Report, please describe the additional work that resulted in the $1.2 million increase to remove primary wires to complete 4-13kV conversions.	The additional work was aerial cable removal required to complete the 4kV to 13kV conversions, which had been omitted from the estimate for the OP scope on the project.	**Section III.A.12.**
RCR-IM-13	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update to the status of the plan application for the Waverly project	The site plan received conditional approval by the Newark Planning Board in December 2021 with memorialization of the compliance resolution in January 2022.	No change
RCR-IM-14	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please indicate if the current forecasted budget remains adequate to address the current delays to the Waverly project. If not, please provide an updated cost estimate for the project.	PSE&G updated the estimate for the Waverly substation project in January 2022. In this updated estimate, the base estimate increased from $29.4 million to $36.2 million, which included: $2.9 million related to equipment awards higher than estimated; $1.1 million from a change in T&D surcharge methodology; $0.2 million from higher than estimated laydown area costs; and $2.6 million related to additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
RCR-IM-15	With reference to page 26 of the Independent Monitor's Draft Third Quarter 2021 Report, please provide an update on the project status of the Woodlyne substation work. Please indicate if the Company anticipates any additional costs for the project.	Civil construction on the Woodlynne substation project commenced in February 2022, and as of the end of the first quarter of 2022 there was no change to the forecasted in-service date (which remains at October 10, 2023 – the same status as of the end of the third quarter of 2021 as shown in **Table 2**). In January 2022, PSE&G updated the Woodlynne estimate, which transitioned from the Study (50% level) to Conceptual (70% level) estimate phase. The updated base estimate increased from $15.8	No change

ID #	Question/Comment	IM Response	Report Changes
		million to $21.3 million, driven by higher than estimated civil construction award ($3.9 million), higher than estimated switchgear award ($0.8 million), and increased carrying cost ($0.8 million).	
RCR-IM-16	With reference to page 32 of the Independent Monitor's Draft Third Quarter 2021 Report, please indicate if the Company currently anticipates that progress for the Grid Modernization - Communication System subprogram remains as forecasted. If not, please explain why not and provide an updated budget and project completion forecast.	The forecast for the Grid Modernization – Communication System subprogram increased from $63.1 million as of the end of the third quarter of 2021 to $66.3 million as of the end of the second quarter of 2022. This increase is predominantly the result of higher forecasts in the fiber projects based on actual conditions and will be further discussed in the upcoming IM 2022 Second Quarter Report.	No change
6/27/2022 Letter from Rate Counsel	Rate Counsel notes that the Report does not clearly state the IM's findings regarding: (1) the effectiveness of IIP investments in meeting project objectives; (2) the cost-effectiveness and efficiency of investments; nor (3) the appropriateness of cost assignments. Findings on these issues are required by the IIP rules. Rate Counsel believes findings by the IM on these topics are critical to proper review of the ESII and the prudency review of the Company's investments.	The IM structures its reports such that the majority of the discussion within the reports is focused on these three primary objectives of the IM review. For additional clarity, a summary of the findings on these three points as been incorporated into the executive summary of the report.	**Section I.**
6/27/2022 Letter from Rate Counsel	In the Third Quarter Report, the IM noted that PSE&G increased its estimate for the Market Street substation by a net $3 million primarily due to 1) additional outside plant overhead and restoration work along with associated material and surcharges based on the complexity of the work and the field conditions, 2) higher than estimated traffic control costs, and 3) reduction in the estimated risk and contingency based on the current risk profile for the project. Rate Counsel is interested in understanding if the Company is experiencing increased traffic control costs across all projects and if increased traffic control costs are now included in new project cost estimates.	See the response to **RCR-IM-10** above.	No change

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2021 FOURTH QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

DECEMBER 21, 2022

Table of Contents

I. Executive Summary 1
II. Program Status 5
A. Key Decisions 5
B. Program Management 6
C. Cost Assignments 7
D. System Performance 12
III. Project Status 15
A. Electric Station Flood Mitigation 15
B. Contingency Reconfiguration 27
C. Grid Modernization – Communication System 30
D. Grid Modernization – ADMS 34
E. Electric Stipulated Base 35
F. Gas M&R Station Upgrades 39

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems	ADMS
Advanced Metering Interface	AMI
Allowance for Funds Used During Construction	AFUDC
Architect and Engineer	A/E
Board of Public Utilities	BPU
Construction Work In Progress	CWIP
Costs of Removal	COR
Distributed Energy Resource Management System	DERMS
Distribution Management System	DMS
Distribution Supervisory Control and Data Acquisition	DSCADA
Energy Strong 2	ES 2
Gas Metering & Regulating	Gas M&R
Independent Monitor	IM
Inside Plant	IP
Issued for Construction	IFC
Issued for Review	IFR
New Jersey Department of Environmental Protection	NJDEP
New Jersey Sports and Exposition Authority	NJSEA
Open Systems International Inc.	OSII
Outage Management System	OMS
Outside Plant	OP
Public Service Electric & Gas	PSE&G
Purchase Order	PO
Record of Decision	ROD
Remote Control Unit	RCU
Remote Terminal Unit	RTU
Risk and Contingency	R&C

Supervisory Control and Data Acquisition ..... SCADA

System Average Interruption Duration Index ..... SAIDI

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the fourth quarter of 2021.

During the fourth quarter of 2021, the bulk of the spend within the ES 2 Program continued to be in the two largest subprograms: Electric Station Flood Mitigation with two additional projects commencing construction during the quarter, bringing half of the projects in the subprogram past the start of construction; and Contingency Reconfiguration where the bulk of the planned recloser installations have now been completed. Within the other subprograms, the Grid Modernization – Communication System subprogram placed three additional fiber installation projects in-service, with 20 fiber installation projects now completed through the ES 2 Program. The Gird Modernization – Communication System also completed the final recloser retrofit installations during the fourth quarter of 2021, with a total 2,318 retrofits installed, and continued the retrofit substation remote terminal unit (RTU) scope, with 10 substations completed out of a forecasted scope of 196 substations. The Grid Modernization – ADMS subprogram completed sprints 11 and 12 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and sprint 9 within the Outage Management System (OMS) scope. The Gas M&R subprogram placed its first project, the Westampton project, in-service while other stations continued to advance pre-construction efforts, including completing site plan packages, ordering long lead materials, and awarding the construction work. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the fourth quarter of 2021, while the State Street (Outside Plant) project held its kickoff meeting and commenced detailed engineering. **Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2021** below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of December 31, 2021

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	$19,768,173	$121,152,744	$347,842,636	35%	Sep 2024	$389M
Contingency Reconfiguration	$8,418,831	$105,693,021	$145,767,428	73%	Dec 2023	$145M
Grid Modernization – Communications	$8,254,991	$48,365,008	$63,628,856	76%	Dec 2023	$64.3M
Grid Modernization – ADMS	$2,828,626	$26,338,279	$43,494,127	61%	Dec 2022	$42.7M

Subprogram	Q4 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Stipulated Base	**$4,669,633**	**$18,055,021**	**$100,000,000**	**18%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$7,006,451**	**$20,175,989**	**$107,798,888**	**19%**	**Dec 2023**	**$101M**
Total*	**$50,946,704**	**$339,780,063**	**$808,531,934**	**42%**	**Dec 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2021**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of December 31, 2021

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$10,500,000	$6,129,738	58%	**10/19/2021** (↑-1)
2. Clay Street	$33,800,000	$3,802,341	11%	11/7/2022 (↑-50)
3. Front Street^	$27,400,000	$2,351,832	9%	11/16/2023 (↓+10)
4. Hasbrouck Heights	$22,700,000	$5,456,031	24%	2/1/2023 (↑-6)
5. Kingsland	$8,300,000	$824,722	10%	6/30/2023 (↑-96)
6. Lakeside Avenue	$47,900,000	$1,173,651	2%	11/8/2023
7. Leonia	$26,400,000	$15,190,427	58%	11/9/2022 (↓+30)
8. Market Street	$29,900,000	$27,012,282	90%	**6/25/2021**
9. Meadow Road	$9,000,000	$1,043,444	12%	9/22/2023
10. Orange Valley	$20,200,000	$797,976	4%	12/29/2023
11. Ridgefield 13kV	$27,600,000	$17,288,355	63%	12/20/2022 (↓+39)
12. Ridgefield 4kV	$21,300,000	$20,646,800	97%	**5/16/2021**
13. State Street	$21,400,000	$8,832,965	41%	9/23/2022
14. Toney's Brook	$18,800,000	$1,526,556	8%	4/21/2023
15. Waverly	$35,400,000	$6,979,786	20%	9/17/2024 (↑-92)
16. Woodlynne	$19,400,000	$2,095,910	11%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover). **Bold dates indicate the actual in-service date.*

(↑)-Indicates the forecasted in-service date advanced from the prior quarter.

(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

^- The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

As indicated in **Table 2**, the projects that started construction prior to the fourth quarter of 2021 (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date, with the Academy Street project also achieving its in-service status during the fourth quarter. The Electric Station Flood Mitigation project estimates remain unchanged from the third quarter of 2021, with a total subprogram estimate of $389 million (comprised of $339.8 in base costs and $49.2 million in R&C). **Table 2** also shows that half of the sixteen projects had movement during the third quarter of 2021 in the forecasted in-service date, with five advancing and three slipping. Of these eight projects, three of the projects (Academy Street, Front Street, Hasbrouck Heights) had forecasted in-service dates change by less than two weeks. The biggest shifts in forecasted in-service dates were on the Kingsland (advancing 96 days) and Waverly (advancing 92 days) projects, with the former driven by material availability that supported schedule improvement and the latter driven by approval of the site plan in December 2021 that improved the construction schedule. The forecasted in-service date for the Waverly project of September 17, 2024, as of the end of 2021, continues to be outside of the ES 2 Program window as PSE&G continues to seek opportunities to improve the schedule. Additional information on the forecasted in-service changes during the fourth quarter of 2021 is provided in the project-specific discussions under **Section III.A.**

As the Covid-19 related impacts continue to be experienced, particularly in the supply chain, and general economic conditions show increased cost pressures, these imparts are starting to be realized in the cost forecasts for the ES 2 Program. These cost impacts were particularly evident within the Gas M&R subprogram that is currently forecasted at approximately $107.8 million (above the Stipulation amount of $101 million), however the overall Program remains forecasted under the total Stipulation amount (forecast of approximately $808.5 million against a Stipulation budget of $842 million). The IM has generally found these cost impacts reflect a change in underlying assumptions and economic conditions from when the initial estimates were prepared and will continue to monitor these cost pressures and any resulting impacts on the Program. Currently, schedule challenges, particularly on the Waverly substation that is forecasted to have its final assets in-service during the third quarter of 2024 and other projects with forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to see if opportunities exist to advance the forecasted in-service dates.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a

new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the fourth quarter of 2021, the following projects/scopes were placed in-service and/or completed:

- Electric Station Flood Mitigation: Academy Street placed in-service.
- Contingency Reconfiguration: Metro Division recloser scope completed.
- Grid Modernization – Communication System: Recloser retrofit scope completed (final 324 completed in the fourth quarter out of a total scope of 2,318 units); two substation RTU retrofits completed (bringing the total to 10 substations out of a current scope of 196); three fiber installation projects were completed (bringing the total to 20 out of a current scope of 38); and one fiber cutover project was completed (bringing the total to nine out of a current scope of 12).
- Electric Stipulated Base: Paramus contingency switchgear placed in-service.
- Gas M&R: Westampton placed in-service.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of 2021 compared to the end of the third quarter of 2021 were as follows:
  - Electric Station Flood Mitigation: subprogram forecast increased approximately $1.3 million (or 0.4%) to approximately $347.8 million.
  - Contingency Reconfiguration: subprogram forecast increased approximately $273,000 (or 0.2%) to approximately $145.8 million.
  - Grid Modernization – Communication System: subprogram forecast increased approximately $518,000 (or 0.8%) to approximately $63.6 million.
  - Grid Modernization – ADMS: subprogram forecast increased approximately $772,000 (or 1.8%) to approximately $43.5 million.
  - Electric Stipulated Base: subprogram forecast remained at $100.0 million.
  - Gas M&R: subprogram forecast increased approximately $12.0 million (or 13%) to approximately $107.8 million.

  As shown above, the nearly every subprogram within the ES 2 Program saw a cost forecast increase during the fourth quarter of 2021. The majority of these increases were relatively minor (under 2%). However, the Gas M&R subprogram saw a 13% forecast increase that was driven by actual costs for materials and construction for the Central and East Rutherford projects that

reflects the ongoing volatility in market conditions compared to when the initial estimates were prepared.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
    - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
    - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
    - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
    - Review and investigation of prior period adjustments and/or corrections to capital accounts.
    - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

  Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On September 20, 2022, a draft IM 2021 Fourth Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2021 Fourth Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2021 Fourth Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

During the fourth quarter of 2021, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-

term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2021, below itemizes the charges to COR for each quarter of 2021, total 2021, total 2020, total 2019 (which was only the fourth quarter) and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through December 31, 2021.

Table 4 – ES 2 Program Costs of Removal as of December 31, 2021

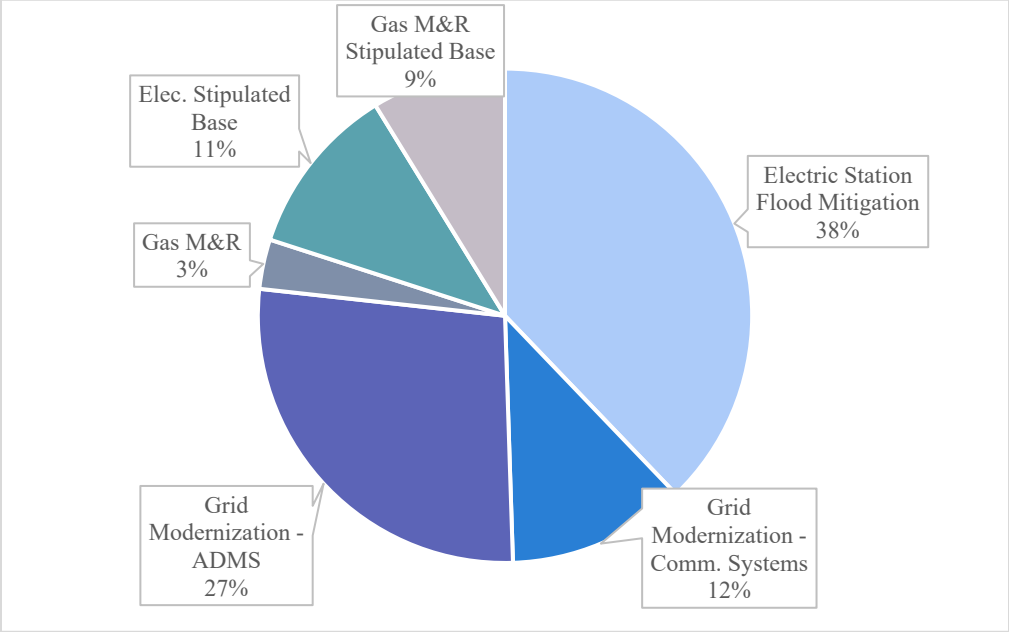
Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)							
Electric Station Flood Mitigation	$1,824.0	$1,464.2	$1,141.0	$1,129.5	$5,558.7	$1,021.1	$0	$6,579.8
Contingency Reconfiguration	$330.7	$811.4	$485.2	$622.9	$2,250.2	$2,198.9	$431.0	$4,880.1
Grid Modernization – Communications	$23.5	$38.6	$37.9	$37.8	$137.8	$24.4	$0	$162.2
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0	$0	$0
Electric Stipulated Base	$146.8	$3.2	$0	$0	$150.0	$0	$0	$150.0
Gas M&R Station Upgrades	($2.2)	$63.5	$87.6	$0	$148.9	$0	$0	$148.9
Gas Stipulated Base	$196.1	$0	$0	$0	$196.1	$0	$0	$196.1
Total	$2,518.9	$2380.9	$1,751.7	$1,790.2	$8,441.7	$3,244.4	$431.0	$12,117.1

The COR charges for the fourth quarter of 2021 primarily reflect COR activities at the Market Street Sub Elimination project, including removal of 4kV cabling and switchgear, circuit breakers, transformers, foundations, and asbestos abatement.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

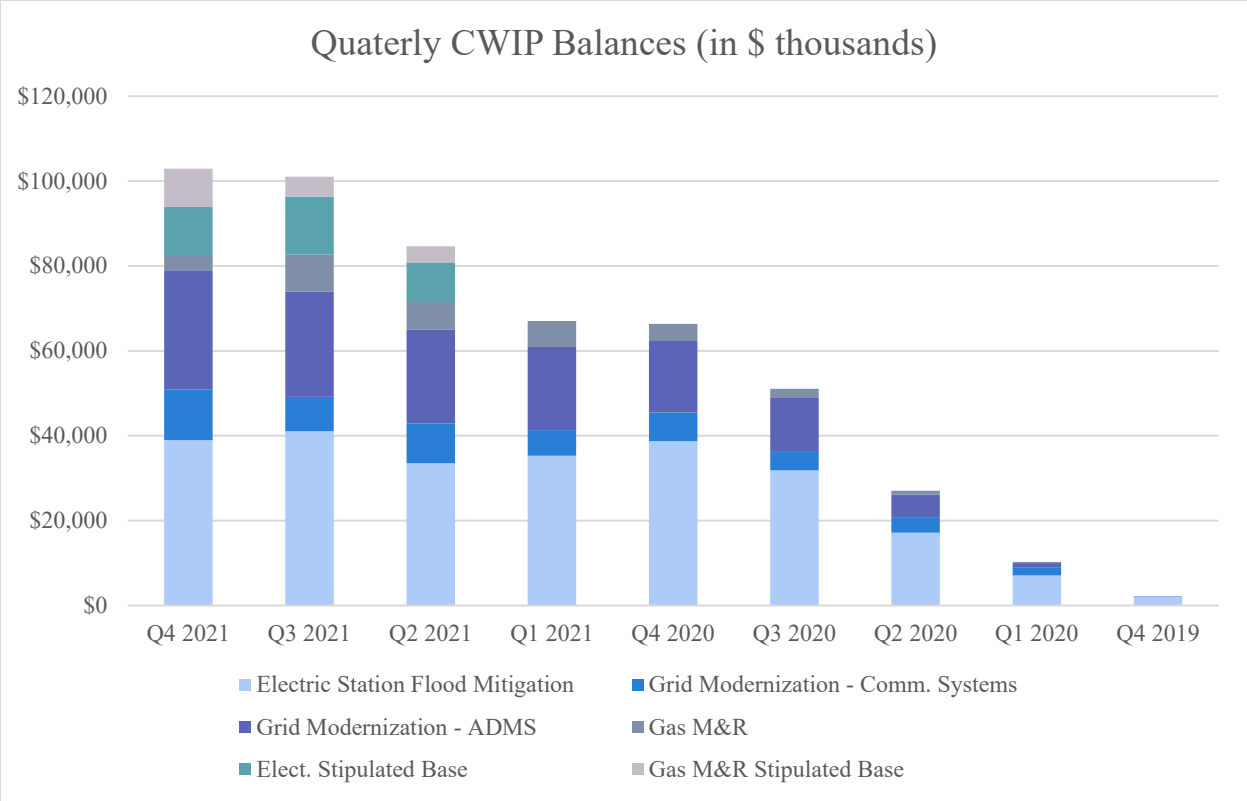
As of December 31, 2021, the Energy Strong CWIP balance was $102.9 million, compared to $101.0 million as of September 30, 2021. The largest components of CWIP as of December 31, 2021, were the State Street ($9.0 million), Waverly ($7.4 million) and Hasbrouck ($5.6 million), projects with the Electric Station Flood Mitigation subprogram, the Central ($4.8 million) Gas Stipulated Base M&R project, and work associated with the Grid Modernization – ADMS subprogram ($28.1 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of December 31, 2021** below.

Figure 1 – ES 2 CWIP as of December 31, 2021



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2021** below depicts the composition of end-of-quarter CWIP balances by subprogram for each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of December 31, 2021



Transfers from CWIP to plant in service totaled $32.4 million during the fourth quarter of 2021, the largest quarterly transfer to date. During the fourth quarter, the Academy Street substation and the Westhampton Gas M&R substation projects were completed and placed in-service, and switchgear assets were placed in-service at the Leonia substation and Paramus substation projects. Total ES 2 Program transfers from CWIP have been $70.8 million through December 31, 2021. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during each quarter of 2021, total AFUDC for the years 2021, 2020, and 2019, and total Energy Strong AFUDC accrued through the end of 2021, is shown below **Table 5 – ES 2 Program AFUDC as of December 31, 2021**.

Table 5 – ES 2 Program AFUDC as of December 31, 2021

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Electric Station Flood Mitigation	**$564.3**	**$581.6**	**$576.7**	**$558.6**	**$2,281.2**	**$936.5**	**$9.9**	**$3,227.6**

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$127.2**	**$105.2**	**$95.5**	**$59.0**	**$386.9**	**$184.3**	**$0.2**	**$571.4**
Grid Modernization – ADMS	**$411.0**	**$363.5**	**$316.9**	**$274.2**	**$1,365.6**	**$352.7**	**$0.1**	**$1,718.4**
Electric Stipulated Base	**$233.6**	**$160.9**	**$80.5**	**$49.6**	**$524.6**	**$44.0**	**$0**	**$568.6**
Gas M&R Station Upgrades (incl. Stip. Base)	**$133.2**	**$157.0**	**$107.6**	**$72.2**	**$470.0**	**$70.0**	**$0.2**	**$540.2**
Total	**$1,469.3**	**$1,368.2**	**$1,177.2**	**$1,013.6**	**$5,028.3**	**$1,587.5**	**$10.4**	**$6,626.2**

AFUDC accrued for ES 2 projects during the fourth quarter of 2021 increased over AFUDC accrued during the third quarter of 2021 as the result of increases in total average CWIP balances for the Grid Modernization – Communications and Grid Modernization – ADMS subprograms and the full quarterly effect of AFUDC accrued on the Paramus substation, which saw its contingency switchgear transferred into in-service in December 2021.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2021, the new AFUDC rate was calculated to be 6.81%, using the capital structure and component costs as of January 31, 2021. This rate is lower than the 2020 rate of 6.95%, primarily due to a significantly lower interest rate used for short-term debt in the AFUDC calculation, and also to a reduction in the Company's embedded cost of long-term debt. In calculating the 2021 AFUDC rate, the Company used (i) a 3.85% embedded cost of long-term debt (vs. 4.02% in 2020), (ii) a short-term debt rate of 0.32% (vs. 1.86% in 2020), and (iii) a cost of equity of 9.60% (unchanged from 2020).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the fourth quarter of 2021, based on data as of November 30, 2021, the recalculated weighted average AFUDC accrual rate (6.84%) did not meet this criterion to warrant changing from the annual rate (6.81%) in effect. Therefore, AFUDC was accrued during the second quarter of 2021 at the calculated rate of 6.81%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to fourth quarter 2021 Energy Strong project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future Energy Strong AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of December 31, 2021** are the allocated overhead costs charged to ES 2 subprograms for the four quarters of 2021, total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of December 31, 2021

Subprogram	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Electric Station Flood Mitigation	**$1,902**	**$2,527**	**$4,352**	**$5,588**	**$14,368**	**$14,023**	**$287**	**$28,678**
Contingency Reconfiguration	**$2,516**	**$3,683**	**$4,006**	**$4,215**	**$14,420**	**$17,109**	**$3,415**	**$34,944**
Grid Modernization – Communications	**$2,692**	**$2,230**	**$2,506**	**$1,743**	**$9,171**	**$3,625**	**$12**	**$12,808**
Grid Modernization – ADMS	**$133**	**$125**	**$124**	**$119**	**$501**	**$426**	**$11**	**$938**
Electric Stipulated Base	**$807**	**$903**	**$287**	**$126**	**$2,123**	**$259**	**$0**	**$2,382**
Gas M&R Station Upgrades (incl. Stip. Base)	**$250**	**$185**	**$169**	**$131**	**$735**	**$291**	**$15**	**$1,041**
Total	**$8,300**	**$9,653**	**$11,444**	**$11,922**	**$41,318**	**$35,733**	**$3,740**	**$80,791**

The overwhelming majority of overhead costs allocated to ES 2 projects during the fourth quarter of 2021 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 74%) of the 2021 fourth quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decreases in overhead costs for the fourth quarter 2021 from the third quarter of 2021 reflect reduced activities that attract overheads, such as material costs and outside services, especially in the Electric Station Flood Mitigation subprogram.

D. System Performance

1. Current Reporting Quarter Major Events

During the fourth quarter of 2021, there was one Major Event reported in PSE&G's service territory from October 25 to November 1, 2021, which involved a State of Emergency related to storm flooding from a Nor'easter and Mutual Aid provided to Jersey City Power & Light. The weather associated with the State of Emergency saw thunderstorms and heavy rains across PSE&G's service territory and resulted in 42,329 PSE&G customers experiencing service interruption with all impacted customers returned to service within 24 hours. None of the switching stations or substations raised and rebuilt during the original Energy Strong Program were affected by floodwaters during this Major Event.

The IM has received PSE&G's report on the performance of its investments from this Major Event and has reproduced the results in **Table 7 – Q4 2021 Major Event Performance** below.

Table 7 – Q4 2021 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ALD 8015	0.12276	0.00000
ALD 8016	0.00654	0.00000
ALD 8022	0.05448	0.00000
BAO 8006		**0.00202**
BAO 8015	0.00023	0.00000
BEA 8001	0.00458	0.00068
BEF 8021	**0.00320**	**0.01943**
BEM 8001	0.00675	0.00000
BEN 8015	0.01246	0.00018
BRU 8012	0.01648	0.01004
CED 8025	0.00153	0.00092
CIN 8031	0.06823	0.00959
CIN 8033	0.14578	0.00376
CIN 8043	0.18459	0.00114
CLK 8015	0.23135	0.00001
CLK 8016	0.39621	0.00020
CLK 8031		**0.00403**
CON 8001		**0.00188**
CRX 8003	0.07703	0.00671
CRX 8005	0.04402	0.00052
CRX 8007	0.78411	0.00308
CUT 8001	0.12150	0.00000
CUT 8042	0.03420	0.00059
DAY 8001	0.15084	0.00846
DFD 8031	0.13025	0.00143
DFD 8041	0.20440	0.00654
DOR 8035	**0.03042**	**0.03873**
DOR 8045	0.00647	0.00128
DUM 4007	0.00474	0.00425
FAW 8011	0.63063	0.01277
FAW 8014	0.21021	0.00814
FAW 8016	0.12332	0.00964
FOH 4006	0.01339	0.00000
GBK 8014	0.30784	0.00037
HAT 8021	0.00164	0.00072
HNC 8025	0.49719	0.00000
HOM 8033	0.08934	0.00438
JAC 8021	0.00477	0.00000
KIL 8013		**0.00000**
KIL 8016	0.01491	0.00000
KIN 8023	0.02086	0.00578
KUS 8043	0.12886	0.00000
LAF 8015	0.00354	0.00000
LAF 8026	0.04406	0.00000
LAU 8012	0.09474	0.00362
LAU 8023	0.82844	0.00736
LAW 8016	0.14895	0.00062
LAW 8023	0.01733	0.00146
LCE 8032	0.30801	0.01615
LCE 8035	0.01296	0.00089
LCE 8042	0.04252	0.00077
LCE 8044		**0.00000**
LCE 8046	0.01692	0.00072
LCU 8051	0.19366	0.00000
LEO 8005	0.61152	0.00000
LEO 8041	0.05678	0.00352
LEV 8016	**0.00021**	**0.00140**
LOC 8012		**0.00000**
LOI 8001	0.00850	0.00000
LUM 8021	0.26968	0.00891

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MAD 8021	0.19231	0.00026
MAD 8031	0.45221	0.00375
MAR 8008	0.30277	0.00067
MAR 8016	0.26336	0.00123
MCL 4007	0.02282	0.00766
MEA 8012		**0.00027**
MEA 8016	0.00228	0.00138
MEA 8024	0.09438	0.03168
MEA 8025	0.11896	0.00119
MEC 8004	0.01253	0.00000
MIN 8013	0.00714	0.00000
MIN 8024		**0.00310**
MON 8002	0.35076	0.00037
MON 8004	0.21535	0.00768
MOT 8003	0.00646	0.00309
MRO 8012	1.08732	0.00054
MRO 8013	0.46710	0.00103
MRO 8023	0.19878	0.01582
MRO 8024	0.29163	0.00441
NBS 8011	0.01516	0.00489
NED 8015	0.09467	0.00000
NED 8016	**0.00729**	**0.00870**
NEW 8011	0.07862	0.00168
NOT 8011		**0.00000**
NRP 4002		**0.00000**
PEK 8036	0.10806	0.00428
PIE 8022		**0.00782**
PLI 8004	**0.01320**	**0.14784**
PLI 8008	0.19552	0.00416
POH 8022	0.01503	0.01445
POH 8023	0.22676	0.00656
RAV 8003	0.00674	0.00000
RUN 8004	0.29484	0.01992
SAD 8008		**0.00000**
SOH 8022	0.16946	0.00230
SUN 8024	**0.00104**	**0.00150**
WAD 8013	0.12231	0.00000
WAD 8041	0.11575	0.00324
WEW 8021	0.21824	0.00073
WEW 8042	0.01304	0.00231
WEW 8044	0.07375	0.00292
WFL 8034	0.04228	0.01247
WOA 4003	0.04886	0.00309
WOR 8013	0.13969	0.00385

**-System Average Interruption Duration Index (SAIDI) calculations are in minutes; bold values indicate circuits with a higher Major Event SAIDI than the 5-year Major Event SAIDI average.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. The average of the circuits impacted by this Major Event compared to circuits not impacted is provided in **Table 8 – Impacted vs. Non-Impacted Circuits During Q4 2021 Major Event**.

Table 8 – Impacted vs. Non-Impacted Circuits During Q4 2021 Major Event

Circuits Impacted in Q4 2021 Major Events (104 circuits)		Circuits Not Impacted in Q4 2021 Major Events (903 circuits)
Average of 5-Year Baseline SAIDI	Average of Q4 2021 SAIDI	Average 5-Year Baseline SAIDI
0.14816	0.00528	0.08234

As shown in **Table 8** above the circuits impacted by the fourth quarter of 2021 Major Events had a worse 5-year average SAIDI than the non-impacted circuits, but also showed improved performance during this Major Event.

As indicated in **Table 7** above, there were 104 circuits impacted by this Major Event 86 of which (or 83%) had a current Major Event SAIDI better than the 5-year Major Event SAIDI average, while 12 circuits had no Major Event outage within the 5-year comparison window, leaving six circuits that both had a prior Major Event outage within the past 5-years and had worse performance during this Major Event. Additional information on the six worse performing circuits from this Major Event is provided below in **Table 9 – Q4 2021 Major Event Additional Information on Selected Circuits.** As shown in **Table 9**, some of these circuits had more than one incident during the Major Event, resulting in a total of 12 incidents from these six circuits, and that some may show zero customers impacted, which reflects the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair).

Table 9 – Q4 2021 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*	Additional Comments
BEF 8021	0.00320	0.01943	5	198	Tree damage
BEF 8021	0.00320	0.01943	47	995	Tree damage
DOR 8035	0.03042	0.03873	872	72	Rotted/broken pole
DOR 8035	0.03042	0.03873	144	225	Open wire
LEV 8016	0.00021	0.00140	0	964	Phase cutout open / large motel customer requested work performed at 8AM
LEV 8016	0.00021	0.00140	47	73	Primary cable burned open
NED 8016	0.00729	0.00870	171	125	Blown fuse
PLI 8004	0.01320	0.14784	305	285	Lightning impact
PLI 8004	0.01320	0.14784	83	157	Defective cable
PLI 8004	0.01320	0.14784	1,720	167	Recloser failure
PLI 8004	0.01320	0.14784	306	206	Recloser failure
SUN 8024	0.00104	0.00150	44	84	Broken ridge pin
**-Calculated in minutes.*					

As indicated in **Table 9**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including

different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Additionally, the circuits in **Table 9** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers).

Beyond the circuit-level performance, the heavy rains from this Major Event did not result in water entering any of the stations that were raised and rebuilt as part of the original Energy Strong Program.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of 2021 compared to the status as of the end of 2019 and end of 2020 is provided below in **Table 10 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of December 31, 2021**.

Table 10 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of December 31, 2021

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C							IS		CO						
	Dec. 2021		KO		C						IS						CO			
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C								IS	CO (Q2)
	Dec. 2021			KO							C				IS					CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Dec. 2021								KO				C						IS	CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C			IS	CO (Q3)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C					IS	CO (Q2)
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout

-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).

*-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.

^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of 2021 is provided below **Table 11 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021**.

Table 11 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	8	Academy Street; Clay Street; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes inside plant and/or outside plant construction.*

Beyond the key activities summarized in **Table 11** above, **Table 12 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2022** summarizes the planned activities for each project during the first quarter of 2022, including any carryover of activities from earlier periods.

Table 12 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q1 2022

Station	Upcoming Activities for Q1 2022	Carryover Activities from Q4 2021
1. Academy Street	• Continued civil and electrical construction	• Continued civil and electrical construction
2. Clay Street	• Major equipment (4kV sheltered aisle switchgear) delivery • Major municipal licenses and permits issuance	• Continued civil construction
3. Front Street	• Civil and electrical drawings Issued for Review (IFR) • Site plan approval	• Continued engineering
4. Hasbrouck Heights	• 90% estimate complete • Start civil construction	• Continued engineering
5. Kingsland	• Continued engineering	• Continued engineering

Station	Upcoming Activities for Q1 2022	Carryover Activities from Q4 2021
6. Lakeside Avenue	• Control drawings IFR • Civil and electrical drawings Issued for Construction (IFC)	• Continued engineering
7. Leonia	• All cutovers complete – Switchgear #1 • Phase 2 electrical construction complete	• Continued electrical construction
8. Market Street	• Municipal licenses and permits issuance for civil demolition	• Continued site demolition
9. Meadow Road	• Continued engineering	• Continued engineering
10. Orange Valley	• Civil and electrical drawings IFR	• Continued engineering
11. Ridgefield 13kV	• Phase 1 civil and electrical construction complete	• Continued civil and electrical construction
12. Ridgefield 4kV	• Project complete	• Project complete
13. State Street	• 90% estimate complete	• Continued civil and electrical construction
14. Toney's Brook	• Relay settings received by Inside Plant (IP) Construction Relay Group	• Continued engineering
15. Waverly	• Phase 3 controls IFR • Start phase 2 civil construction	• Continued engineering
16. Woodlynne	• Continued engineering	• Continued engineering

The current project estimates, including base and R&C amounts, are shown below in **Table 13 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021**. **Table 13** also shows the current estimate level based on PSE&G's estimating processes and as approved by the Utility Review Board (URB), the actual spend, and percentage of actuals to estimate as of the end of 2021.

Table 13 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,800,000	$700,000	$10,500,000	$8,681,267	$6,129,738	58%
2. Clay Street	Conceptual	$30,300,000	$3,500,000	$33,800,000	$31,302,000	$3,802,341	11%
3. Front Street*	Study	$23,000,000	$4,400,000	$27,400,000	$25,884,733	$2,351,831	9%
4. Hasbrouck Heights	Conceptual	$20,500,000	$2,200,000	$22,700,000	$20,380,526	$5,456,031	24%
5. Kingsland	Study	$5,400,000	$2,900,000	$8,300,000	$6,418,541	$824,722	10%
6. Lakeside Avenue	Study	$39,400,000	$8,500,000	$47,900,000	$39,356,279	$1,173,651	3%
7. Leonia	Definitive	$24,900,000	$1,500,000	$26,400,000	$24,887,497	$15,190,427	58%
8. Market Street	Definitive	$29,100,000	$800,000	$29,900,000	$28,201,027	$27,012,282	90%
9. Meadow Road	Study	$7,200,000	$1,800,000	$9,000,000	$7,497,449	$1,043,444	12%

Project	Estimate Level	Base	Risk & Contingency	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
10. Orange Valley	Study	$16,000,000	$4,200,000	$20,200,000	$14,769,606	$797,976	4%
11. Ridgefield 13kV	Conceptual	$25,300,000	$2,300,000	$27,600,000	$26,601,954	$17,288,355	63%
12. Ridgefield 4kV	Definitive	$20,800,000	$500,000	$21,300,000	$20,726,799	$20,646,800	97%
13. State Street	Conceptual	$19,100,000	$2,300,000	$21,400,000	$19,417,411	$8,832,965	41%
14. Toney's Brook	Conceptual	$16,200,000	$2,600,000	$18,800,000	$16,254,329	$1,526,556	8%
15. Waverly	Study	$29,400,000	$6,000,000	$35,400,000	$36,199,218	$6,979,786	20%
16. Woodlynne	Study	$15,800,000	$3,600,000	$19,400,000	$21,264,000	$2,095,910	11%
Subprogram Total		**$332,200,000**	**$47,800,000**	**$380,000,000**	**$347,842,636**	**$121,152,745**	**31%**

**-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- Eight of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the fourth quarter of 2021, with five advancing and three slipping. The biggest changes came on the Kingsland (advancing 96 days from October 4, 2023 to June 30, 2023), Waverly (advancing 92 days from December 18, 2024 to September 17, 2024), and the Clay Street (slipping 50 days from November 7, 2022 to December 27, 2022) projects.

- Following the Market Street and Ridgefield 4kV projects being placed in-service during the second quarter of 2021, the Academy Street achieved in-service status as of October 19, 2021. The Leonia and Ridgefield 13kV projects also reached partial in-service status during the fourth quarter of 2021 (with each project placing one of its two switchgear in-service).

- There were no updated estimates completed in the subprogram during the fourth quarter of 2021 and the overall subprogram forecast increased $1.3 million (or 0.4%) to $347.8 million as of the end of 2021. The forecast continues to remain under the current subprogram estimate of $380.0 million and the Stipulation amount of $389.0 million.

- The IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. As of the end of 2021, the Waverly project continues to show a final in-service date in 2024, although it has advanced from December to September 2024. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to

September 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023.

1. Academy Street

During the fourth quarter of 2021, $698,611 was spent on the Academy Street project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $6.1 million. The variance in spend during the fourth quarter of 2021 was primarily the result of commissioning activities being charged to the Fairmount 69kV Project (same site location) and less than estimated trailing costs after the project was placed in-service. The commissioning activities that were wrongly charged to the Fairmount 69kV project were budgeted to the Academy Street project and were performed by Commissioning Engineers that worked on the Fairmount 69kV project prior to working on the Academy Street project. This error was identified and corrected during the monthly forecast variance analysis process when it was realized that this work was done as planned with cash flow forecasted, but not included in the October actual costs.

The primary activity conducted during the fourth quarter of 2021 was the completion of commissioning for the switchgear with the project being achieving in-service status on October 19, 2021 when the first circuit was completed. Civil and electrical construction work will continue to the fourth quarter of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						*Forecast*
$150,398	$4,224,550	$378,939	$405,843	$271,396	$698,611	$2,551,529

Actuals to Date	Estimate	% of Actuals to Estimate
$6,129,738	$10,500,000	58%

2. Clay Street

During the fourth quarter of 2021, $546,400 was spent on the Clay Street project compared to a forecast of approximately $642,000, which brought the total spend to approximately $3.8 million. The forecasted in-service date for the Clay Street project as of the end of the fourth quarter of 2021 advanced 50 days from the end of the third quarter to November 7, 2022. This shift was the result of a revision to the construction sequence to split the foundation activity, regulators installation, and commissioning activities along with the cutovers into two phases. This also helps alleviate space and manhole access constraints on the project.

The primary activities on the Clay Street project during the fourth quarter of 2021 included the phase 2 civil and electrical drawings being IFC and the civil and electrical POs issued, followed by the start of civil construction late in December.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$116,409	$879,339	$565,030	$595,723	$1,099,440	$546,400	$27,499,659

Actuals to Date	Estimate	% of Actuals to Estimate
$3,802,341	$33,800,000	11%

3. Front Street

During the fourth quarter of 2021, $1,090,782 was spent on the Front Street project compared to a forecast of approximately $1.06 million, which brought total spend to approximately $2.4 million. The forecasted in-service date for the Front Street project as of the end of the fourth quarter of 2021 slipped ten days from the end of the third quarter to November 16, 2023.

The primary activities on the Front Street project during the fourth quarter of 2021 included the issuance of the switchgear PO, completion of the license and permitting package, and the submittal of the project site plan.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$0	$0	$0	$190,915	$1,070,135	$1,090,782	$23,532,901

Actuals to Date	Estimate	% of Actuals to Estimate
$2,351,832	$27,400,000	9%

4. Hasbrouck Heights

During the fourth quarter of 2021, $3,364,236 was spent on the Hasbrouck Heights project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $5.5 million. The variance in spend during the fourth quarter of 2021 was driven by the contractor's invoice lower than previously accrued and 26kV control house abatement work pushing out pending completion of electrical removal of racks. Despite that work shifting out, the forecasted in-service date for the Hasbrouck Heights project as of the end of the fourth quarter of 2021 advanced six days from the end of the third quarter to February 1, 2023.

Notable activities completed during the fourth quarter of 2021 included the delivery of the 4kV sheltered aisle switchgear and capacitor bank.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$149,848	$1,129,934	$550,795	$189,748	$71,469	$3,364,236	$14,924,495

Actuals to Date	Estimate	% of Actuals to Estimate
$5,456,031	$22,700,000	24%

5. Kingsland

During the fourth quarter of 2021, $293,352 was spent on the Kingsland project compared to a forecast of approximately $243,000, which brought the total spend to $824,722. The forecasted in-service date for the Kingsland project as of the end of the fourth quarter of 2021 advanced 96 days from the end of the third quarter to June 30, 2023. This advancement in the forecasted in-service date was driven by material availability that supported schedule improvement.

During the fourth quarter of 2021, primary activities on the Kingsland project included constructability reviews, the issuance of the license and permitting package, and the IFC release of civil and electrical drawings.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$104,112	$209,667	$30,621	$36,886	$150,084	$293,352	$5,593,820

Actuals to Date	Estimate	% of Actuals to Estimate
$824,722	$8,300,000	10%

6. Lakeside Avenue

During the fourth quarter of 2021, $128,323 was spent on the Lakeside Avenue project compared to a forecast of approximately $168,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at November 8, 2023.

Notable activities completed during the fourth quarter of 2021 included approval of the site plan at a zoning board meeting, the IFR release of civil and electrical drawings, and a constructability review.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$148,943	$453,994	$178,973	$174,268	$89,151	$128,323	$38,182,628

Actuals to Date	Estimate	% of Actuals to Estimate
$1,173,651	$47,900,000	3%

7. Leonia

During the fourth quarter of 2021, $790,673 was spent on the Leonia project compared to a forecast of approximately $1.08 million, which brought the total spend to approximately $15.2 million. The variance in spend during the fourth quarter was driven by a temporary resource availability within the Division that shifted some non-critical path work to future periods. The forecasted in-service date for the Leonia project as of the end of the fourth quarter of 2021 slipped 30 days from the prior quarter to November 9, 2022.

Notable activities completed during the fourth quarter of 2021 included the 13kV switchgear #1 being placed in-service on October 19, 2021.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$44,792	$6,033,379	$2,809,628	$4,146,544	$1,365,412	$790,673	$9,697,069

Actuals to Date	Estimate	% of Actuals to Estimate
$15,190,427	$26,400,000	58%

8. Market Street

During the fourth quarter of 2021, $1,719,125 was spent on the Market Street project compared to a forecast of approximately $2.25 million, which brought the total spend to approximately $27.0 million. The variance in spend during the fourth quarter was largely the result of poor weather and resource constraints, including unplanned emergency work that pulled resources from the project.

Notable activities conducted during the fourth quarter of 2021 included the completion of electrical demolition at the station, which was placed out of service on June 25, 2021 following the completion of the 4kV to 13kV conversion work.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						*Forecast*
$251,193	$16,079,601	$4,035,880	$3,147,454	$1,779,029	$1,719,125	$1,188,746

Actuals to Date	Estimate	% of Actuals to Estimate
$27,012,281	$29,900,000	90%

9. Meadow Road

During the fourth quarter of 2021, $144,070 was spent on the Meadow Road project compared to a forecast of $88,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Meadow Road project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at September 22, 2023.

Detailed engineering commenced during the fourth quarter of 2021, in addition the New Jersey Department of Environmental Protection (NJDEP) permit was received and a site plan exception was granted.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$63,128	$535,081	$117,672	$70,220	$113,271	$144,070	$6,454,006

Actuals to Date	Estimate	% of Actuals to Estimate
$1,043,444	$9,000,000	12%

10. Orange Valley

During the fourth quarter of 2021, $95,128 was spent on the Orange Valley project compared to a forecast of approximately $67,000, which bought the total spend to approximately $798,000. The forecasted in-service date for the Orange Valley project as of the end of the fourth quarter of 2021 remained unchanged from the prior quarter at December 29, 2023.

During the fourth quarter of 2021, major activities on the Orange Valley project included the start of detailed engineering, the redevelopment agreement approval by the City Council, vendor drawings received for final switchgear arrangement, and the site plan was submitted.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$77,029	$362,895	$7,291	$146,827	$108,807	$95,128	$13,971,630

Actuals to Date	Estimate	% of Actuals to Estimate
$797,976	$20,200,000	4%

11. Ridgefield 13kV

During the fourth quarter of 2021, $2,394,930 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.4 million, which brought the total spend to approximately $17.3 million. The variance in spend during the third quarter of 2021 was driven by manhole rebuild work being delayed due to the contractor's workload and Division manhole work and cable pulling being postponed due to IP conduit installation completed later than expected. These delays contributed to the forecasted in-service date for the Ridgefield 13kV project as of the end of the fourth quarter of 2021 slipping 39 days from the prior quarter to December 20, 2022.

Notable activities completed during the fourth quarter of 2021 included the start and completion for commissioning of the 13kV switchgear #2, which was placed in-service on December 16, 2021.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$205,982	$6,232,692	$3,215,967	$3,665,283	$1,573,500	$2,394,930	$9,313,599

Actuals to Date	Estimate	% of Actuals to Estimate
$17,288,355	$27,600,000	63%

12. Ridgefield 4kV

During the fourth quarter of 2021, $241,884 was spent on the Ridgefield 4kV project compared to a forecast of approximately $267,000, which brought the total spend to approximately $20.4 million. The project was placed in-service on May 16, 2021.

The primary activities performed during the fourth quarter of 2021 included the completion of IP civil demolition.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022
Actuals						*Forecast*
$143,414	$11,239,534	$2,808,765	$4,559,439	$1,653,764	$241,884	$80,000

Actuals to Date	Estimate	% of Actuals to Estimate
$20,646,799	$21,300,000	97%

13. State Street

During the fourth quarter of 2021, $7,068,233 was spent on the State Street project compared to a forecast of approximately $7.9 million, which brought the total spend to approximately $8.8 million. The variance in spend during the quarter was driven by the project receiving only half of the forecasted feeder rows due to a Covid-19 outbreak at the vendor's facilities. The forecasted in-service date for the State Street project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at September 23, 2022.

Notable activities performed on State Street during the fourth quarter of 2021 included the commencement of electrical construction, continued civil construction, and the delivery of the 4kV sheltered aisle switchgear. IP construction on the project advanced to 20% complete, up from 10% at the end of the prior quarter, with the total project reported at 28% complete.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$77,590	$662,148	$237,415	$216,479	$571,099	$7,068,233	$10,584,445

Actuals to Date	Estimate	% of Actuals to Estimate
$8,832,966	$21,400,000	41%

14. Toney's Brook

During the fourth quarter of 2021, $403,672 was spent on the Toney's Brook project compared to a forecast of approximately $341,000, which brought the total spend to approximately $1.5 million. The forecasted in-service date for the Toney's Brook project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at April 21, 2023.

Notable activities achieved during the fourth quarter of 2021 included the controls drawings IFC and control and power cables material received on site.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$211,940	$373,096	$88,947	$289,769	$159,132	$403,672	$14,727,774

Actuals to Date	Estimate	% of Actuals to Estimate
$1,526,555	$18,800,000	8%

15. Waverly

During the fourth quarter of 2021, $277,739 was spent on the Waverly project compared to a forecast of approximately $437,000, which brought the total spend to approximately $6.3 million. The variance in second quarter spend was largely driven an engineering milestone that shifted from September to October and work delayed in September due to lack of resources in the Metro Division. The forecasted in-service date for the Waverly project as of the end of the fourth quarter of 2021 advanced 92 days from the prior quarter to September 17, 2024, which was driven by the site plan approval that in turn improved the construction schedule by advancing the anticipated permit approval dates that are precursors to the start of construction activities.

As previously reported, the project team requested a special meeting to maintain the project's schedule, which was held in March 2021. The Newark Planning Board denied the site plan application at this meeting, which required the project team to prepare a new site plan application. The revised site plan was submitted to the Newark Planning Board in early September 2021 with the site plan approved during a December 2021 meeting. Other activities performed during the fourth quarter of 2021 included the receipt of vendor drawings (final switchgear controls) and civil and electrical drawings IFC.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$103,748	$2,460,815	$659,572	$2,837,893	$277,739	$640,019	$29,219,432

Actuals to Date	Estimate	% of Actuals to Estimate
$6,979,786	$35,400,000	20%

16. Woodlynne

During the fourth quarter of 2021, $148,804 was spent on the Woodlynne project compared to a forecast of approximately $302,000, which brought the total spend to approximately $2.1 million. The variance in spend during the fourth quarter was driven by lower than estimated spend on civil supervision, security, and safety, and the A/E not reaching a planned payment milestone in December. The forecasted in-service date for the Woodlynne project as of the end of the fourth quarter of 2021 remains unchanged from the prior quarter at October 10, 2023.

Preliminary design work continued to progress during the fourth quarter of 2021, with minimal other activities conducted on the Woodlynne project this quarter as the bulk of this project's activities planned for 2022-2023, including construction scheduled to commence in early 2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$110,982	$993,298	$282,187	$132,630	$428,009	$148,804	$19,168,090

Actuals to Date	Estimate	% of Actuals to Estimate
$2,095,910	$19,400,000	11%

B. Contingency Reconfiguration

During the fourth quarter of 2021, work continued to progress in the Contingency Reconfiguration subprogram with all four Divisions continuing to install reclosers with a total of 109 installed during the quarter and 122 commissioned. **Table 14 – ES 2 Program Recloser Status as of December 31, 2021** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the current status of engineering, installation, and commissioning; while **Figure 3 – 2021 Recloser Installations as of December 31, 2021** compares the installed reclosers as of the end of the third quarter of 2021 against PSE&G's 2021 installation plan.[1]

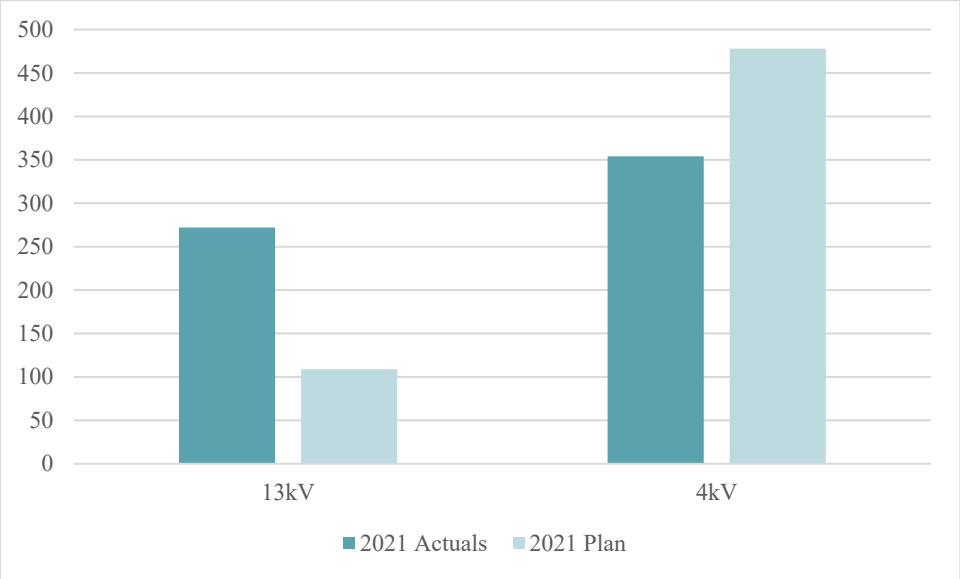
Table 14 – ES 2 Program Recloser Status as of December 31, 2021

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q4 Qty.	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*
13kV	29	249	948	49	272	933	61	288	932
4kV	13	261	515	60	354	511	61	353	510

[1] Note that as discussed in the IM 2021 First Quarter Report (Section IV.A.1.) and the IM 2021 Second Quarter Report (Section II.A.1.), the number of reclosers identified the Contingency Reconfiguration subprogram was updated after the 2021 installation plan was established, which resulted in a net reduction of the 4kV reclosers planned for the subprogram and a net increase of the 13kV reclosers planned for the subprogram.

Type	Engineering Packages Completed (1 recloser ea.)			Reclosers Installed			Reclosers Commissioned		
	Q4 Qty.	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*	*Q4 Qty.*	*2021 Total*	*Program Total*
Total	42	510	1,463	109	626	1,444	122	641	1,442

Figure 3 – 2021 Recloser Installations as of December 31, 2021



As shown in **Table 14** and **Figure 3**, PSE&G continued to maintain progress during the fourth quarter of 2021 and as of the end of the year only 23 units remained to be installed to complete the recloser scope of the subprogram. As also shown in **Figure 3**, the 2021 installation plan shifted the focus primarily to the 4kV reclosers from the 13kV reclosers that were prioritized in 2020. However, actual installations of 13kV reclosers were above the initial 2021 plan due to the change in reclosers planned for the subprogram following PSE&G's review, which resulted in an additional 275 13kV reclosers and 90 4kV reclosers (also discussed in Section IV.A.1. of the IM 2021 First Quarter Report and Section II.A.1. of the IM 2021 Second Quarter Report).

As previously discussed in prior IM reports, the Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021. In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders. Because of this, commencement of the full Fuse Saver scope was pushed to 2022. However, PSE&G opted to install the remaining Fuse Saver units from its initial inventory to capture additional cost and performance data to better inform the planning and execution of the full scope of work. This resulted in an additional three 2-

phase units and 30 1-phase units being installed during the second half of 2021, bringing the total number of Fuse Savers installed through the end of 2021 to 113 units out of a forecasted 1,713 units. Costs incurred in the Fuse Saver scope during the fourth quarter of 2021 related to project management costs and direct costs (labor, material, engineering, storage, traffic control), which included some older invoices for work performed prior to the fourth quarter of 2021.

Concerning the forecasted number of Fuse Savers planned to be installed during the ES 2 Program, PSE&G continues to utilize an iterative process to evaluate the number of devices anticipated for the Fuse Saver scope of work. The targeted number of Fuse Saver units is revised based on updated field assessments as well as the final number of units driven by the average cost per unit based on the most optimal mix of locations given the fixed budget. For example, if an identified location requires a pole replacement based on the field conditions, it will have a much higher installation cost than a location not requiring a pole replacement.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2021**. This table also shows the forecasted final in-service dates as of the end of the third quarter of 2021 to show movement to the forecast as of the end of the fourth quarter of 2021.

Table 15 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of December 31, 2021

Scope & Division		Q3 2021 Forecasted Completion Date	Q4 2021 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022
	Metro	1/31/2022	12/31/2021 (Actual)
	Palisades	12/31/2021	2/28/2022
	Southern	1/31/2022	1/31/2022
Fuse Savers	Central	9/30/2023	9/30/2023
	Metro	10/31/2023	10/31/2023
	Palisades	12/30/2023	12/30/2023
	Southern	10/31/2023	9/30/2023

As shown in **Table 15**, the forecasted final in-service dates remained constant for the majority of the scopes, with the Metro and Palisades Divisions recloser efforts and the Southern Division Fuse Saver efforts having new forecasted in-service dates. Within the Metro Division recloser scope, improvements in the material availability allowed the schedule to be completed earlier than previously forecasted, with the final installations completed in December 2021. The Palisades Division recloser scope saw the final in-service date shift to February 2022 as the result of three recloser in the Division that required the development and implementation of a unique operating procedure. While the only change to the Fuse Saver scope of work was the Southern Division advancing one month as the installation schedules continue to be developed and refined prior to the commence of that scope in 2022.

The Contingency Reconfiguration subprogram costs through the end of 2021 are presented in **Table 16 – ES 2 Contingency Reconfiguration Costs as of December 31, 2021**.

Table 16 – Contingency Reconfiguration Costs as of December 31, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals								
Reclosers	Central	$2,737,167	$12,050,820	$3,007,686	$2,392,608	$2,116,213	$2,336,304	$24,640,799	$25,368,784	97%
	Metro	$2,231,431	$10,726,610	$587,396	$4,051,716	$3,926,036	$2,803,260	$24,326,450	$24,483,210	99%
	Palisades	$2,515,569	$12,119,436	$3,109,037	$2,591,672	$1,991,442	$588,372	$22,915,527	$23,162,771	99%
	Southern	$2,081,220	$12,405,684	$5,008,143	$4,065,891	$2,742,523	$2,221,485	$28,524,946	$28,937,756	99%
Fuse Savers	Central	$9,970	$789,937	$375,811	$107,384	$255,092	$115,831	$1,654,025	$12,061,825	14%
	Metro	$7,557	$561,915	$216,511	$89,860	$144,511	$56,860	$1,077,214	$10,969,592	10%
	Palisades	$7,468	$522,454	$133,552	$63,808	$276,182	$103,572	$1,107,036	$8,462,697	13%
	Southern	$9,792	$859,014	$65,018	$56,845	$263,207	$193,147	$1,447,023	$12,320,792	12%
Total		**$9,600,174**	**$50,035,871**	**$12,503,156**	**$13,419,784**	**$11,715,206**	**$8,418,831**	**$105,693,021**	**$145,767,428**	**73%**

Findings & Observations:

- PSE&G continued to maintain progress on the recloser installations during the fourth quarter of 2021, including completing the Metro Division scope, with the remaining Divisions expected to be completed early in 2022.
- The forecasted completion of the recloser scope of this subprogram remained unchanged from the prior quarter for three of the four Divisions, while the Palisades Division forecasted completion slipped two months based on three reclosers in the Division that required the development and implementation of a unique operating procedure. For the Fuse Savers, while three of the four Division's completion dates remained unchanged, the Southern Division advanced their forecasted completion date one month reflecting an updated installation schedule.
- The Contingency Reconfiguration subprogram forecast remained relatively static as of the end of the fourth quarter of 2021 from the prior quarter, with the total forecast increasing by approximately $273,000 (or 0.2%) to $145.8 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system.

During the fourth quarter of 2021, the final recloser retrofit installations were completed with 324 units installed during the quarter. In total, 2,318 retrofit reclosers were installed on the Program compared to an initial forecast of 2,561, with the variance driven by updated system status information. Also during the fourth quarter of 2021, two additional retrofits of substation RTUs were completed, bringing the total as of the end of 2021 to 10 substations completed out of a currently forecasted scope of 196 substations. The retrofit substation RTU scope is planned to ramp-up in 2022 with all installation expected to be completed by the fourth quarter of 2022. Under the Wireless Network scope, radios continue to be prepared for the Fuse Savers, which reflects the remaining spend associated with the Wireless Network.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects since removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of December 31, 2021**.

Table 17 – Fiber Projects by Division as of December 31, 2021

Division	Fiber Installation	Fiber Cutover
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights; Thirty Second Street	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***

During the fourth quarter of 2021, three additional fiber installation projects (Irvington, Irvington Sub HQ, and Morgan Street) were placed in-service. This brought the total projects in-service as of the end of 2021 to 20 for the fiber installation projects and nine for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of December 31, 2021** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of 2021 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of December 31, 2021

Project Name	Q4 2021 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued engineering
Bordentown	*In-Service (Q3 2021)*
Carteret	IP IFC issued
Central Ave	*In-Service (Q3 2021)*
Central HQ	OP overhead construction underway
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	IP IFCs issued; IP civil construction complete; battery installation complete; OP construction mobilized
East Orange	*In-Service (Q1 2021)*
Edison	IP IFC issued
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	IP civil work complete; OP overhead contractors mobilized; IP IFC issued
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering
Hadley Rd HQ	Continued engineering

Project Name	Q4 2021 Status
Haledon	County road occupancy permit received to fix a break in the line between Haledon and Hawthorne substations
Harrison	*In-Service (Q3 2021)*
Howell Street	Removed from ES 2 Program after evaluation determined that the redundancy and resiliency benefits would not be obtained through this project (which shares a site with the Jersey Steet station that already has a TFI rack installed)
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	OP IFC issued; OP construction mobilized; IP IFC issued
Lehigh Avenue	Preliminary engineering
Mechanic Street	IP IFC issued
Metro HQ	*In-Service (Q1 2021)*
Montclair	IP civil work complete
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	Continued construction
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	Continued construction
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering
Waverly	Preliminary engineering
West New York	OP construction mobilized
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	Completion dependent upon Fort Lee fiber installation project
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	Completion dependent upon West New York fiber installation project
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 196 units	10 cutovers completed

For the three fiber projects placed in-service during the fourth quarter of 2021 (Irvington, Irvington Sub HQ, and Morgan Street), the original budget and actual costs as of December 31, 2021 are presented in **Table 19 – Q4 2021 Fiber Projects Budget vs. Actual Cost**.

Table 19 – Q4 2021 Fiber Projects Budget vs. Actual Cost

Project	Original Budget (ES 2 filing)	Actual Costs as of Dec. 2021	Budget-Actual Variance
Irvington	$300,000	$157,175	($142,825)
Irvington Sub HQ	$300,000	$578,009	$278,009

Project	Original Budget (ES 2 filing)	Actual Costs as of Dec. 2021	Budget-Actual Variance
Morgan Street*	$0	$457,217	$457,217
**-Morgan Street was not on the initial project list in the ES 2 filing and was added after PSE&G reviewed the fiber requirements and current status of all substations and operations centers to verify communication needs (see the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report).*			

The overall Grid Modernization – Communication System subprogram costs through the end of 2021 are presented in **Table 20 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021**.

Table 20 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021

Scope & Division		2019	2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Total to Date	Forecast	% of Actuals to Forecast
		Actuals								
Retrofit Reclosers	Central	$0	$884,278	$1,067,295	$1,027,602	$715,214	$494,686	$4,189,074	$6,786,837	62%
	Metro	$0	$818,620	$436,089	$683,893	$733,376	$509,422	$3,181,399	$5,590,363	57%
	Palisades	$0	$825,174	$754,869	$965,416	$888,467	$506,721	$3,940,648	$6,200,559	64%
	Southern	$0	$929,058	$956,444	$1,005,852	$1,082,897	$817,622	$4,791,874	$7,325,098	65%
Fiber	Central	$1,691	$2,418,851	$796,586	$1,349,407	$1,007,245	$2,820,417	$8,394,196	$9,513,484	88%
	Metro	$1,457	$1,866,697	$340,713	$831,337	$1,198,777	$715,269	$4,954,250	$7,765,395	64%
	Palisades	$1,582	$2,046,762	$248,558	$725,030	$605,647	$2,023,898	$5,651,478	$6,132,422	92%
	Southern	$4,731	$910,483	$645,219	$1,029,156	$591,125	$200,977	$3,381,691	$3,381,691	100%
	Cutovers*	$0	$876,502	$323,458	$86,115	$109,880	$87,603	$1,483,558	$3,018,032	49%
Wireless Network		$74,306	$6,035,441	$287,086	$312,404	$124,015	$559,481	$7,392,732	$7,914,973	93%
Bulk Purchase**		$0	$1,524,874	$450,013	($154,037)	($335,637)	($481,105)	$1,004,108	$0	-
Total		**$83,767**	**$19,136,741**	**$6,306,330**	**$7,862,176**	**$6,721,006**	**$8,254,991**	**$48,365,008**	**$63,110,594**	**77%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Findings & Observations:

- During the fourth quarter of 2021, the final 325 recloser retrofit installations were completed. In total, 2,318 retrofit reclosers were installed in the Program. The retrofit substation RTU scope commenced at the end of the fourth quarter of 2021, with 10 substations completed out of a forecasted scope of 196 substations.
- Three additional fiber installation projects were placed in-service during the fourth quarter of 2021, bringing the total number of projects in-service to 20 fiber installation projects and nine fiber cutover projects. The fiber scope is expected to be completed by the end of 2022.
- The forecast for the Grid Modernization – Communication system subprogram slightly increased from $63.1 million as of the end of the third quarter of 2021 to $63.6 million as of the end of the fourth quarter of 2021. Overall, the subprogram forecast of $63.6 million continues to remain below the adjusted Stipulation budget amount of $64.3 million (following the prior $7.7 million transfer of funds to the Grid Modernization – ADMS subprogram).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The primary activities in 2021 are focused on the continued development of the systems and platforms that comprise this subprogram.

The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the fourth quarter of 2021 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q4 2021 Activities:
    - Compiled advance metering interface (AMI) interface requirements.
    - Completed sprints 11 and 12.
- Forecasted Completion as of the end of the fourth quarter of 2021: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q4 2021 Activities:
    - Completed sprint 9 with Open Systems International Inc. (OSII).
    - Onboarded new Project Manager for OMS scope.
    - Reviewed integration/Mulesoft documentation.
    - Completed drafts of SAP integration documentation.
    - Completed onsite workshops at ADMS lab in Edison with System Integrator.
- Forecasted Completion as of the end of the fourth quarter of 2021: 12/23/2022.

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q4 2021 Activities:

- Completed network segmentation for Newark; drafted network segmentation for Edison.
- Secured vulnerability testing vendor (Dragos).
- Completed setup for industrial defender.

- Forecasted Completion as of the end of the fourth quarter of 2021: 12/10/2021.

With the ADMS Platform being placed in-service in December 2021, this meant the domains (environments) used to manage and support the SCADA system that is in production and used for distribution operations as the system of record were in-service. The platform environments are also currently being used for DMS/DERMS and OMS as these components progress (for example, in performance and release testing). Changes to the shared environments are coordinated and controlled by a team comprised of two Environment Managers (one from PSE&G and one from OSII) and the ADMS-OMS Solution Architect.

The Grid Modernization – ADMS subprogram costs through the end of 2021 are presented in **Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2021**.

Table 21 – ES 2 Grid Modernization – ADMS Costs as of December 31, 2021

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$36,213	$16,447,624	$2,488,980	$2,168,187	$2,368,648	$2,828,626	$17,155,847

Actuals to Date	Forecast	% of Actuals to Forecast
$26,338,279	$43,494,127	61%

Findings & Observations:

- While the OMS component of the Grid Modernization – ADMS subprogram slipped 21 days from its status as of the end of the third quarter of 2021, the forecasted in-service date for the subprogram continues to remain at December 2022.
- The Grid Modernization – ADMS forecast as of the end of 2021 increased approximately $772,000 from the third quarter of 2021, with the total forecast now at $43.5 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric outside plant higher design and construction standards and/or electric stations life cycle subprograms described in the original ES 2 filing.[2] The bulk of outside plant higher design and construction standards work is planned to commence in January 2022. In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station

[2] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2021**.

Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date*
1. Hamilton	Study	$14,500,000	$3,700,000	$18,200,000	$3,503,394	19%	10/12/2022
2. Paramus	Study	$14,800,000	$5,400,000	$20,200,000	$7,908,965	39%	12/29/2022 (↓)
3. Plainfield	Study	$18,400,000	$4,200,000	$22,600,000	$4,266,426	19%	11/8/2022 (↓)
4. Woodbury	Study	$15,400,000	$3,300,000	$18,700,000	$2,164,988	12%	12/27/2022
5. State Street (OP)	Study	$19,700,000	$3,000,000	$22,700,000	$211,247	1%	4/30/2023 (↓)

**-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 22**, of the five life cycle station upgrade projects, the Paramus, Plainfield, and State Street OP projects each saw their respective forecasted in-service dates slip during the fourth quarter of 2021, reversing the advancement in these projects gained in the third quarter of 2021. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- Construction continued on the Hamilton, Plainfield, and Woodbury projects, which commenced during the third quarter of 2021, and also continued on Paramus, which started in the second quarter of 2021. The Paramus project placed the contingency switchgear in-service in December 2021.
- The forecasted in-service dates for the Paramus, Plainfield, and State Street OP projects each slipped during the fourth quarter of 2021, reflective of actual site conditions and resource availability. Each of the original four life cycle station upgrade projects remains forecasted for completion in the fourth quarter of 2022 while the State Street OP project is forecasted for completion in the second quarter of 2023.

1. Hamilton

During the fourth quarter of 2021, $1,419,949 was spent on the Hamilton project against a forecast of approximately $1.6 million. The variance between forecasted and actual spend in the fourth quarter was driven by foundations and 4kV duct banks not completed as planned due to contractor unavailability

(though no resulting change to the forecasted in-service date). This brought total spend on the project to approximately $3.5 million through the end of 2021.

Notable activities conducted during the fourth quarter of 2021 included the commencement of the first phase of civil works on the project, which includes the installation of foundations for the 4kV equipment, the grounding grid, and new OP duct banks. The electrical scope is expected to commence in the first quarter of 2022.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$362,372	$236,783	$400,855	$1,083,435	$1,419,949	$13,014,013

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,503,395	$18,200,000	$16,517,408	21%

2. Paramus

During the fourth quarter of 2021, $968,622 was spent on the Paramus project against a forecast of approximately $908,000. This brought total spend on the project to approximately $7.9 million through the end of 2021. The forecasted in-service date for the Paramus project slipped from November 11, 2022, as of the end of the third quarter of 2021, to December 29, 2022, as of the end of the fourth quarter of 2021. This shift was the result of manhole repairs required and correction of a condensation issue within the contingency (temporary) feeder row gear. The condensation was a result of the design of some of the rear panels on the contingency feeder rows as well as the settings on the heaters and humidifiers. The units which did not have vented panels experienced the condensation and when this was corrected, and the settings on the heaters and humidifiers were adjusted, the issue was resolved.

Notable activities conducted during the fourth quarter of 2021 included:

- Civil and Electrical POs issued;
- Control drawings IFC;
- Construction permits received; and,
- The contingency switchgear placed in-service.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$0	$840,200	$358,846	$4,176,989	$1,564,308	$968,622	$12,937,137

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$7,908,965	$20,200,000	$20,846,102	38%

3. Plainfield

During the fourth quarter of 2021, $1,787,450 was spent on the Plainfield project against a forecast of approximately $2.3 million. The variance between forecasted and actual spend during the fourth quarter was driven by civil activities delayed due to permitting and material availability from the Palisades Division. This brought total spend on the project to approximately $4.3 million through the end of 2021. The forecasted in-service date for the Plainfield project slipped from October 17, 2022, as of the end of the third quarter of 2021, to November 8, 2022, as of the end of the fourth quarter of 2021. This shift was the result of an unknown underground obstruction requiring foundation design changes and the determination that a NJ Transit temporary access permit is required for approved crane use in proximity to the nearby NJ Transit tracks. The unknown underground obstruction at Plainfield included existing below grade concrete structures and direct buried cables that were not included in the record drawings and also resulted in marginal increases to the engineering and construction costs on the project.

Notable activities conducted during the fourth quarter of 2021 included:

- Civil PO issued;
- OP circuit cutovers completed;
- Control drawings IFC; and,
- Electrical construction out for bid.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2024
Actuals						*Forecast*
$0	$682,325	$214,632	$367,543	$1,214,476	$1,787,450	$17,898,069

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$4,266,426	$22,600,000	$22,164,495	19%

4. Woodbury

During the fourth quarter of 2021, $353,658 was spent on the Woodbury project against a forecast of approximately $544,000. The variance between forecasted and actual spend in the fourth quarter was driven by foundation work not completed as planned due to material availability and a missed accrual for December work. This brought the total spend on the project to approximately $2.2 million through the end of 2021. The unavailable material involved perimeter wall foundation materials that shifted the construction of the wall foundation from December 2021 to January 2022 (though no resulting change to the forecasted in-service date).

Notable activities conducted during the fourth quarter of 2021 included the issuance of construction permits and the commencement of OP work.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$551,165	$540,138	$356,225	$363,802	$353,658	$15,919,012

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$2,164,988	$18,700,000	$18,084,000	12%

5. State Street (Outside Plant)

During the fourth quarter of 2021, $139,953 was spent on the State Street (OP) project against a forecast of approximately $296,000. The variance between forecasted and actual spend in the fourth quarter was driven by lower spend than estimated for A/E supporting underground design work, less A/E work completed in December than forecasted, and the November A/E invoice lower than accrued. This brought the total spend on the project to approximately $211,000. The forecasted in-service date for the State Street OP project slipped from March 2, 2023, as of the end of the third quarter of 2021, to April 30, 2023, as of the end of the fourth quarter of 2021. This shift was the result of a review of the anticipated resource availability.

Notable activities conducted during the fourth quarter of 2021 included the project kickoff meeting and the commencement of detailed engineering.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$0	$0	$0	$17,633	$53,660	$139,953	$19,501,342

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$211,247	$22,700,000	$19,712,589	0%

F. Gas M&R Station Upgrades

Through the end of 2021, primary activities in the Gas M&R subprogram continued to focus on advancing the pre-construction activities for the five projects not in construction, while the Westampton project continued its construction activities in support of reaching an October 2021 in-service date. **Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2021** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 23 – ES 2 Gas M&R Summary Status as of December 31, 2021

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service**
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$3,020,373	10%	Dec 2022
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$4,903,727	17%	Dec 2022
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$2,314,498	14%	Dec 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service**
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$895,473	8%	Dec 2022
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$1,039,637	8%	Dec 2023
6. Westampton	Definitive	$9,100,000	$900,000	$10,000,000	$8,002,281	80%	***Oct 2021***
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$20,175,989**	**18%**	**Dec 2023**

**-Included in the Stipulated Base.*
***-Bold/italics indicate actual in-service date achieved.*
(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*
(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

The in-service dates for the Gas M&R projects as of the end of the fourth quarter of 2021 remained static from the status at the end of the prior quarter. The Westampton project was placed in-service as of October 22, 2021, which was the forecasted date as of the end of the prior quarter.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and awarding the construction work. The Westampton project, which commenced construction in April 2021, was placed in-service as of October 22, 2021, and will have some remaining restoration and punch list work ongoing in 2022.
- The forecast increased on the Central and East Rutherford projects based on the actual PO/contract pricing received for materials and construction, as well as additional engineering efforts. These cost pressures are being evaluated on the other remaining projects. However, despite these increases, the overall subprogram forecast of $107.8 million remains below the current total estimate of $109.9 million (although both are above the Stipulation amount of $101.0 million).
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, while the cost pressures noted above have pushed the forecast over the Stipulation amount. During the fourth quarter of 2021 there were no updates to the Gas M&R project estimates and the forecast in-service dates remained unchanged from the prior quarter, while the first of the six Gas M&R projects was also placed in-service (Westampton).

1. Camden

During the fourth quarter of 2021, $937,617 was spent on the Camden project compared to a forecast of approximately $948,000, which brought the total spend to approximately $3.0 million. The forecasted in-service date for the Camden project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Camden project during the fourth quarter of 2021 included:

- Held pre-bid site walk through;
- Received construction bids; and,
- Resolution compliance completed for City of Camden.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$13,326	$859,350	$505,693	$290,839	$413,548	$937,617	$23,366,961

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,020,373	$29,300,000	$26,387,333	11%

2. Central

During the fourth quarter of 2021, $3,409,826 was spent on the Central project compared to a forecast of approximately $4.0 million, which brought the total spend to approximately $4.9 million. The forecasted in-service date for the Central project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Central project during the fourth quarter of 2021 included:

- Awarded construction contract;
- Held pre-construction meeting and reviewed permit package with contractor;
- Received fully executed agreement with Transco; and,
- Installed air bridges and matting over underground pipeline crossings.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The current forecast of $34.0 million reflects an increase of approximately $8.2 million from the forecast as of the end of the prior quarter. This increase was driven by the actual PO/contract pricing received for materials and construction and additional engineering efforts. The increase in construction costs reflects the current market conditions, as PSE&G had awarded the work to the lowest bidder, at a price 12.5%-59% below other bidders. The additional engineering efforts involve design evolution on the building configuration (increasing from two buildings to four) and foundations, which also ties into the final piping design. Other design factors include the relocation of the station by-pass away from the regulation building in case of station emergency.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$6,869	$670,582	$315,258	$190,109	$311,084	$3,409,826	$29,064,009

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$4,903,727	$29,000,000	$33,967,736	14%

3. East Rutherford

During the fourth quarter of 2021, $996,202 was spent on the East Rutherford project compared to a forecast of approximately $927,000, which brought the total spend to approximately $2.3 million. The forecasted in-service date for the East Rutherford project as of the end of 2021 remains unchanged from forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the East Rutherford project during the fourth quarter of 2021 included:

- Completed IFC drawing page turn with project team and A/E;
- Awarded construction contract;
- Held pre-construction meeting with contractor;
- Held meeting with Transco to discuss site requirements;
- Received water discharge surface permit; and,
- Submitted response to New Jersey Sports and Exposition Authority (NJSEA) comments on permit application.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The current forecast of $18.1 million reflects an increase of approximately $4.3 million from the forecast as of the end of the prior quarter. This increase was driven by the actual PO/contract pricing received for materials and construction and additional engineering efforts. The increase in construction costs reflects the current market conditions, as PSE&G had awarded the work to the lowest bidder, at a price 52%-102% below other bidders. The additional engineering efforts involve a change from one larger heater to two smaller heaters to facilitate maintenance, increased piping wall thickness to mitigate noise levels, updates to temporary regulator skids to allow operational controls during construction, the identified need for upgraded electrical service, and larger diameter piping and valves with longer regulator runs that resulted in an increase to the building size.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$9,010	$521,865	$337,573	$260,112	$189,737	$996,202	$15,809,210

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$2,314,498	$16,500,000	$18,123,708	13%

4. Mount Laurel

During the fourth quarter of 2021, $101,143 was spent on the Mount Laurel project compared to a forecast of approximately $96,000, which brought the total spend to approximately $895,000. The forecasted in-service date for the Mount Laurel project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 30, 2022.

Notable activities completed on the Mount Laurel project during the fourth quarter of 2021 included:

- Opened construction bid;
- Issued material procurement PO; and,
- Site plan deemed completed and placed on Burlington County Planning Board agenda for approval.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$5,965	$362,167	$155,351	$149,682	$121,165	$101,143	$8,504,527

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$895,473	$11,400,000	$9,400,000	10%

5. Paramus

During the fourth quarter of 2021, $118,557 was spent on the Paramus project compared to a forecast of approximately $93,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Paramus project as of the end of 2021 remains unchanged from the forecast as of the end of the third quarter at December 29, 2023.

Notable activities completed on the Paramus project during the fourth quarter of 2021 included:

- Submitted permit package to township;
- Received comments on site plan application; and,
- Held air permit coordination meeting.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$8,842	$462,452	$227,854	$129,694	$92,239	$118,557	$10,460,363

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,039,637	$13,700,000	$11,500,000	9%

6. Westampton

During the fourth quarter of 2021, $1,443,107 was spent on the Westampton project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $8.0 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that will carry over into 2022.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2022-2023
Actuals						*Forecast*
$8,395	$1,032,670	$478,072	$3,217,496	$1,822,542	$1,443,107	$417,830

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,002,281	$10,000,000	$8,420,111	95%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2021 FOURTH QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

DECEMBER 21, 2022

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2021 Fourth Quarter Report Formally Submitted to the IM

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>S-INF-1</td><td><u>Reference Q4 2021 Report, Page 11, Table 7 – Q4 2021 Major Event Performance</u>
For the 104 circuits impacted by the Q4 2021 Major Event that received investments during either the original Energy Strong Program or through Energy Strong 2, please compare the cumulative five (5)-year baseline System Average Interruption Duration Index (“SAIDI”) of all circuits to the cumulative Q4 2021 SAIDI of all circuits.</td><td>Out of a total of 1,007 circuits, 104 circuits were impacted by the Q4 2021 Major Events and 903 circuits were <u>not</u> impacted by this Major Event. The SAIDI of these circuits is as follows:

<table><tr><th colspan="2">Circuits Impacted in Q4 2021 Major Events (104)</th><th>Circuits <u>Not</u> Impacted in Q4 2021 Major Events (903)</th></tr><tr><td>Average of 5-Year Baseline SAIDI</td><td>Average of Q4 2021 SAIDI</td><td>Average 5-Year Baseline SAIDI</td></tr><tr><td>0.14816</td><td>0.00528</td><td>0.08234</td></tr></table>
As shown above the circuits impacted by the Q4 2021 Major Event had a worse 5-year average SAIDI than the non-impacted circuits, but also showed improved performance during this Major Event.</td><td>Section II.D.1. (new Table 8)</td></tr>
<tr><td>S-INF-2</td><td><u>Reference Q4 2021 Report, Page 13, Table 8 – Q4 2021 Major Event Additional Information on Selected Circuits</u>
With respect to the six (6) circuits improved within Energy Strong or Energy Strong 2 that had worse performance during the Q4 2021 Major Event than the five (5)-year baseline:
a. Please describe the improvements made to each circuit within the Energy Strong or Energy Strong 2 program.
b. Please estimate why these investments were not effective in improving the circuit’s SAIDI.</td><td>Regarding these comments on circuit performance:
a. The Contingency Reconfiguration subprogram for both the Energy Strong and ES 2 programs involved increasing the number of sections in present loop designs utilizing reclosers, providing alternative circuit feeds or circuit reconfigurations, and placing new devices on the system that will provide reclosing where it previously did not exist and allow PSE&G to receive outage notifications without customer calls. Reclosers essentially serve as an automatic, high-voltage electric switch that sense and interrupt fault currents and automatically restore service after a momentary outage has occurred. Momentary outages may include situations such as: windblown conductors touching one another; lightning surges flashing over an insulator; small animals bridging between an energized line and grounded surface; tree branches touching energized lines; or switching surges that flash over an insulator. If a fault is permanent, the recloser locks open after a preset number of operations isolating the faulted section from the main</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		part of the system to reduce the outage area and help repair crews quickly locate the problem and restore power. b. It is the IM's opinion that the performance of the circuits listed in **Table 9** (renumbered after the new **Table 8** was added in response to **S-INF-1**), which had worse SAIDI metrics in this Major Event than the 5-year average, reflects the nature of these specific outages where circumstances such as additional restoration effort required (such as pole replacement), equipment failure, and/or very low customer counts (lowering the restoration priority) contributed to the comparatively worse performance.	
S-INF-3	**Reference Q4 2021 Report, Page 16, Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of December 31, 2021** Please provide additional details about the facilities placed in-service at the Leonia and Ridgefield 13kV substations during Q4 2021, which resulted in these substations being classified as partially in-service.	Regarding the partial in-service status achieved by the Leonia and Ridgefield 13kV projects involved one of each projects' switchgears being placed in-service: • For Leonia, the 13kV switchgear #1 was placed in-service as of October 19, 2021 (while switchgear #2 was placed in-service on June 29, 2022). • For Ridgefield 13kV, the 13kV switchgear #2 was placed in-service as of December 16, 2021 (while switchgear #1 is forecasted to be placed in-service in December 2022).	No change
S-INF-4	**Reference Q4 2021 Report, Page 19, Academy Street Substation** Regarding the Academy Street substation project, please refer to the statement "The variance in spend during the fourth quarter of 2021 was primarily the result of commissioning activities being charged to the Fairmount 69kV Project (same site location) and less than estimated trailing costs after the project was placed in-service." a. Please clarify if the costs for commissioning activities that were charged to the Fairmount 69kV project were originally budgeted within the Academy Street substation project. b. If so, please provide additional details explaining why these costs were charged to the Fairmount 69kV project.	The Fairmount 69kV project and the ES 2 Academy Street project are co-located on a common site and are being jointly executed. The commissioning activities that were wrongly charged to the Fairmount 69kV project were budgeted to the Academy Street project and were performed by Commissioning Engineers that worked on the Fairmount 69kV project prior to working on the Academy Street project. This error was identified and corrected during the monthly forecast variance analysis process when it was realized that this work was done as planned with cash flow forecasted, but not included in the October actual costs.	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
S-INF-5	**Reference Q4 2021 Report, Page 25, Waverly Substation** Regarding the Waverly substation project, please estimate the additional costs expected to be incurred as a result of the increased scope of the revised site plan.	As indicated in response to RCR-IM-6 in the IM 2021 Third Quarter Report, PSE&G updated the Waverly project estimate in January 2022, with the base estimate increasing from $29.4 million to $36.2 million. Of this increase, approximately $2.6 million was related to the site plan revisions, including: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million).	No change
S-INF-6	**Reference Q4 2021 Report, Page 25, Woodlynne Substation** Regarding the Woodlynne substation project, please provide additional details about the cost savings resulting from "the A/E not reaching a planned payment milestone in December."	The A/E not reaching a planned payment milestone in December resulted in lower than forecasted spend specifically for the fourth quarter of 2021 and has a negligible impact on the overall project cost.	No change
S-INF-7	**Reference Q4 2021 Report, Page 27, Continency Reconfiguration Subprogram** Regarding the Fuse Saver component of the Contingency Reconfiguration subprogram, it is noted that the Company currently forecasts a total of 1,713 units. It is further noted that the Company previously reduced forecasted Fuse Saver installations from 2,572 units to 1,967 units. (See Q1 2021 Report, Page 27). Please discuss the Company's rationale for further reducing the scope of the Fuse Saver component and indicate if any further reductions are expected.	PSE&G continues to utilize an iterative process to evaluate the number of devices anticipated for the Fuse Saver scope of work. The targeted number of Fuse Saver units is revised based on updated field assessments as well as the final number of units driven by the average cost per unit based on the most optimal mix of locations given the fixed budget. For example, if an identified location requires a pole replacement based on the field conditions, it will have a much higher installation cost than a location not requiring a pole replacement.	**Section III.B.**
S-INF-8	**Reference Q4 2021 Report, Page 28, Table 15 – Contingency Reconfiguration Costs as of December 31, 2021** Please provide additional details about the nature of the costs incurred for the Fuse Saver component of the Contingency Reconfiguration subprogram in Q4 2021, given that full Fuse Saver scope was pushed to 2022.	While the full Fuse Saver scope was pushed to 2022, installations of the remaining pilot program units continued in the fourth quarter of 2021, with five additional units installed. One additional unit was also engineering during the fourth quarter of 2021. The costs incurred from the Fuse Saver scope during the fourth quarter of 2021 included project management costs and direct costs (labor, material, engineering, storage, traffic control), which included some older invoices for work prior to the fourth quarter of 2021.	**Section III.B.**
S-INF-9	**Reference Q4 2021 Report, Page 29, Grid Modernization – Communication System Subprogram**	Regarding these comments on the Grid Modernization – Communication System subprogram: a. PSE&G initially planned for 2,561 reclosers to be retrofitted with wireless radio communications.	**Section III.C.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>a. Please compare the final number of retrofit reclosers (2,318) to originally budgeted totals.
b. What is attributed to the forecasted scope of substation RTU retrofits being reduced from 204 units in the IM's Q3 2021 Report to 196 units in the IM's Q4 2021 Report?
c. Refer to the statement "Also during the fourth quarter of 2021, two additional retrofits of substation RTUS were completed, bringing the total as of the end of 2021 to 10 substations completed…" please reconcile this with the IM's Q3 2021 Report, which indicated that nine (9) fiber cutover projects had been placed in-service through Q3 2021. (See Q3 Report, Page 34)</td><td>b. The reduction in planned substation RTU retrofits was due to updated system status information.
c. Under this subprogram, PSE&G is cutting over new fiber installations to 12 existing substations (referenced as the "Fiber Cutover Projects" in Table 18), as of the end of 2021, nine of these 12 projects were completed, which is unchanged from the status as of the end of the third quarter of 2021. This subprogram also involves the retrofitting of RTUs to existing substations and as of the end of 2021, 10 RTU retrofits had been completed. As of the end of the third quarter of 2021, eight RTU retrofits had been completed (although Table 18 from the IM 2021 Third Quarter Report identified nine complete as an error).</td><td></td></tr>
<tr><td>S-INF-10</td><td><u>Reference Q4 2021 Report, Page 30, Grid Modernization – Communication System Subprogram</u>
Regarding the Grid Modernization – Communication System subprogram, it is stated that "During the fourth quarter of 2021, three additional fiber installation projects (Irvington, Irvington Sub HQ, and Morgan Street) were placed in-service." For each of these projects placed in-service during Q4 2021, please compare the final cost to the budgeted cost.</td><td>For the fiber projects placed in-service during the fourth quarter of 2021, the original budgeted cost compared to the actual costs is as follows:
<table>
<tr><th>Project</th><th>Original Budget (ES 2 filing)</th><th>Actual Costs as of Dec. 2021</th></tr>
<tr><td>Irvington</td><td>$300,000</td><td>$157,175</td></tr>
<tr><td>Irvington Sub HQ</td><td>$300,000</td><td>$578,009</td></tr>
<tr><td>Morgan Street*</td><td>$0</td><td>$457,217</td></tr>
<tr><td colspan="3">*-Morgan Street was not on the initial project list in the ES 2 filing and was added after PSE&G reviewed the fiber requirements and current status of all substations and operations centers to verify communication needs (see the ROD on this discussed in Section IV.A. of the IM 2020 Third Quarter Report).</td></tr>
</table></td><td>Section III.C. (new Table 19)</td></tr>
<tr><td>S-INF-11</td><td><u>Reference Q4 2021 Report, Page 31, Table 18 – ES 2 Grid Modernization – Communication System Costs as of December 31, 2021</u>
Regarding the Wireless Network component of the Grid Modernization – Communication System subprogram, Table 18 reports actual spending through Q4 2021 of $7,392,732 and total forecasted spending of $7,914,973. Please provide additional</td><td>The Wireless Network, as noted, was placed in-service as of December 16, 2021. Remaining work in the Wireless Network scope relates to providing radios for the Fuse Savers currently being installed, which constitutes the approximately half million in remaining spend.</td><td>Section III.C.</td></tr>
</table>

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>details about the work included within this $522,241 of additional spending, given that the Wireless Network scope was placed in-service as of December 16, 2021. (See Q3 2021 Report, Comment S-INF-10)</td><td></td><td></td></tr>
<tr><td>S-INF-12</td><td><u>Reference Q4 2021 Report, Page 32, Grid Modernization – ADMS Subprogram</u>
For each component of the Grid Modernization – ADMS subprogram (DMS/DERMS, OMS, ADMS), please compare the currently forecasted cost to the originally budgeted cost.</td><td>The original budget and forecasted costs as of December 2021 for the major Grid Modernization – ADMS components are as follows:
<table>
<tr><th>Scope</th><th>Original Budget</th><th>Estimate at Completion (as of Dec 2021)</th><th>Variance</th></tr>
<tr><td>OMS</td><td>$27,289,272</td><td>$27,820,234</td><td>$530,962</td></tr>
<tr><td>DMS/DERMS</td><td>$6,436,387</td><td>$6,665,333</td><td>$228,946</td></tr>
<tr><td>Platform Upgrade</td><td>$4,630,926</td><td>$4,631,667</td><td>$741</td></tr>
<tr><td>ADMS Hardware</td><td>$4,356,031</td><td>$4,376,892</td><td>$20,861</td></tr>
<tr><td>Total</td><td>$42,712,616</td><td>$43,494,127</td><td>$781,511</td></tr>
</table></td><td>No change</td></tr>
<tr><td>S-INF-13</td><td><u>Reference Q4 2021 Report, Page 33, Grid Modernization – ADMS Subprogram</u>
Regarding the ADMS platform component of the Grid Modernization – ADMS subprogram, please indicate if a competitive bidding process was used to select the vulnerability testing vendor (Dragos). If so, please indicate if Dragos submitted the lowest bid.</td><td>PSE&G used a competitive bidding process to select the vulnerability testing vendor. Dragos, the selected vendor, was not the lowest cost bidder, but was the only bidder who met all the requirements for this scope of work.</td><td>No change</td></tr>
<tr><td>S-INF-14</td><td><u>Reference Q4 2021 Report, Page 33, Grid Modernization – ADMS Subprogram</u>
Please discuss how the ADMS platform (completed in December 2021) will be leveraged while the DMS/DERMS and OMS remain under development until December 2022.</td><td>The ADMS Platform put in service the domains (environments) used to manage and support the SCADA system that is in production and used for distribution operations as the system of record. The platform environments are also currently being used for DMS/DERMS and OMS as these components progress. (for example, OMS- SIT/SAT/Performance/Release Testing, DMS/DERMS – Performance/Release Testing).
Changes to the shared environments are coordinated and controlled by a team comprised of two Environment Managers (one from PSE&G and one from OSII) and the ADMS-OMS Solution Architect.</td><td>Section III.D.</td></tr>
<tr><td>S-INF-15</td><td><u>Reference Q4 2021 Report, Page 38, Gas M&R Station Upgrades – Camden</u></td><td>In the first quarter of 2022, PSE&G updated its estimate for the Camden Gas M&R Project, which resulted in a $10.7 million estimate increase from the Study level estimate to a current estimate of $36.6 million. While details of this</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Camden Gas M&R project, please indicate if the construction bids received were higher than anticipated, similar to the Central an East Rutherford Gas M&R projects.	estimate will be discussed in the upcoming IM 2022 First Quarter Report, the contractor bids had a minimal impact compared to other cost drivers (site plan remediation impacts, additional electric load requirements, final building design, schedule constraints, etc.).	
S-INF-16	**Reference Q4 2021 Report, Page 39, Gas M&R Station Upgrades** Regarding the Central and East Rutherford Gas M&R projects: a. Please indicate if the construction contracts were awarded to the lowest bidders. If not please explain. b. Please provide additional information about the need for additional engineering efforts.	Regarding these comments on the Central and East Rutherford Gas M&R projects: a. For both these projects, the construction contracts were awarded to the lowest bidder (which was also the highest overall evaluated contractor). On the Central project, the winning bidder's price proposal was 12.5%-59% below the other bidders; while on the East Rutherford project, the winning bidder's price proposal was 52%-102% below the other bidders. b. On Central, the additional engineering efforts involved design evolution of the building configuration (increasing from two buildings to four) and foundations, which also ties to the final piping design. Other factors include a relocation of the station by-pass away from the regulation building in case of station emergency. On East Rutherford, the additional engineering efforts involved a change from one large heater to two smaller heaters to facilitate maintenance, increased piping wall thickness to mitigate noise levels, updates to temporary regulator skids to allow operational controls during construction, the identified need for upgraded electrical service, and larger diameter piping and valves with longer regulator runs that resulted in an increase to the building size.	**Sections III.F.2.** and **III.F.3.**
S-INF-17	**Reference Q4 2021 Report, Page 39, Gas M&R Station Upgrades – East Rutherford** Regarding the East Rutherford Gas M&R project, please provide additional details about the New Jersey Sports and Exposition Authority ("NJSEA") comments on the permit application. Please also indicate if any scope changes are expected as a result of the NJSEA comments.	The comments received from NJSEA on the East Rutherford projects were similar to comments typically received from other municipal planning or zoning boards, and included requests such as: Provide documentation that the standby generator complies with NAJC 19:4-7; Provide a gate detail; Verify that all equipment susceptible to flooding are above elevation of 9 feet NACD88; All imported fill must be approved by NJSEA; Provide copies of approvals from other agencies with jurisdiction such as NJDEP and Bergen County Soil Conservation District; Applicant must comply with the signage requirements to satisfy the East Rutherford Fire Department. PSE&G expects no scope changes to the project as a result of the comments.	No change
S-INF-18	**Reference Q4 2021 Report, Page 40, Gas M&R Station Upgrades**	During the second quarter of 2022, PSE&G updated the estimates for the Mount Laurel and Paramus Gas M&R projects (in addition to the other projects within this subprogram). The Mount Laurel estimate included cost increases identified	No change

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Mount Laurel and Paramus Gas M&R projects, please discuss if the Company expects increased costs for materials and construction, similar to the Central and East Rutherford Gas M&R projects.	for construction and materials based on current quotes received, while the Paramus estimate had no change to the base estimate, but increased R&C by $6.2 million based in part on the observed cost pressures experienced on the more advanced projects in the subprogram.	
S-INF-19	**Reference Q4 2021 Report, Page 41, Gas M&R Station Upgrades – Westampton** Please indicate if the completed Westampton Gas M&R project incorporated any major scope changes as compared to the originally planned scope of work.	No major scope changes were introduced on the Westampton Gas M&R project.	No change
RCR-IM-1	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Orange Valley substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Orange Valley forecasted in-service date is in February 2024.	No change
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Waverly substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Waverly forecasted in-service date is in April 2024.	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Leonia substation including actual in-service date or anticipated in-service date.	The Leonia project was placed in-service in November 2022.	No change
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the Ridgefield 13kV substation including actual in-service date or anticipated in-service date.	As of the end of the third quarter of 2022 (most recent set of schedule data available as of the date of this report), the Ridgefield 13kV forecasted in-service date continues to be December 2022.	No change
RCR-IM-5	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of anticipated in-service date of any substation work expected to be completed in 2022.	As of the end of 2021, the following Electric Station Flood Mitigation projects were forecasted to be put in-service during 2022: Clay Street, Leonia, Ridgefield 13kV, and State Street. Of these projects, all remain forecasted as of the end of the third quarter of 2022 to be in-service during 2022 with the exception of the Clay Street project that has slipped to March 2023.	No change
RCR-IM-6	With reference to page 2 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company would seek IIP accelerated	PSE&G informed the IM that it does not have authority to seek accelerated recovery for any substation work that is put into service after December 31, 2023 under the ES 2 Stipulation and Order approving same (dated 9/11/2019).	No change

ID #	Question/Comment	IM Response	Report Changes
	cost recovery treatment for substation work that is not completed until after December 31, 2023. If so, please explain.	However, in accordance with paragraph 20 of the Stipulation, PSE&G does have the option of seeking Board approval to extend the Program beyond the term provided.	
RCR-IM-7	With reference to page 3 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain how the approved Waverly substation site plan has enabled PSE&G to accelerate the scheduled completion date by 92 days.	As of the end of the third quarter of 2021, PSE&G forecasted to have the Waverly construction permits approved in July 2022, which was based on projected dates provided from the City of Newark and drives the construction start and in-service dates. The City of Newark had better than anticipated progress in advancing the permitting process, which improved the construction permit timeline to March 2022 and allowed the PSE&G team to implement improved dates for the construction start and in-service milestones. PSE&G also continues to evaluate options to further improve the schedule, such as sequencing activities in parallel if possible. See also the response to **RCR-IM-9**.	**Section III.A.15.**
RCR-IM-8	With reference to page 10 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if PSE&G has any plans to review the July 2003 BPU-approved cost allocation schedule. If so, please indicate the proposed timing of the review. If not, please explain why not.	PSE&G indicated it has reviewed the 2003 schedule and the amended and restated agreement approved in September 2022.	No change
RCR-IM-9	With reference to pages 18 and 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please identify and describe what work activities and project schedule items are being examined to accelerate the scheduled completion date of the Waverly project that is currently scheduled for closeout in first quarter of 2025.	As of the end of the third quarter of 2021, the Waverly project was forecasted to go in-service on 12/18/2024. This was driven by construction permits being anticipated to be received in July 2022 (based on projected dates from the Newark City). Based on better than expected permitting progress identified in the fourth quarter of 2022, the construction permit approval timeline advanced to March 2022, which supported an improved construction start date and overall in-service date, which advanced to 9/17/2024 as of the end of 2021. After the construction permits were received in the first quarter of 2022, the project management team worked with the construction team and Division to improve the construction schedule and sequence by paralleling activities where possible that further advanced the forecasted in-service date to February/March 2024. As part of the regular schedule review efforts, PSE&G will continue to seek opportunities to improve the schedule. See also the response to **RCR-IM-7**.	**Section III.A.15.**
RCR-IM-10	With reference to pages 18 and 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please state whether any accelerated or compressed scheduling of the Waverly substation project would increase the current forecasted cost of	Accelerating or compressing the schedule can potentially add costs due to the extra resources/shifts required, which would somewhat be offset by lower carrying costs from the reduced project duration. The actual impacts would be dependent on the specific factors involved (e.g. what the specific carrying costs	No change

ID #	Question/Comment	IM Response	Report Changes
	$36.19 million. If so, please explain. If not, please explain why not.	are, how many extra resources required, how much the schedule was compressed, etc.).	
RCR-IM-11	With reference to page 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update to the Fairmont 69kV project and please indicate if the Company anticipates addition[al] project costs will be allocated from the Academy Street to the Fairmont 69kV project.	There was no allocation of costs from the Academy Street project to the Fairmount 69kV project, the issue was commissioning activities that were budgeted to the Academy Street project but charged in error against the Fairmount 69kV project. This was identified and corrected during the monthly forecast variance analysis process. See also the response to **S-INF-4**.	**Section III.A.1.**
RCR-IM-12	With reference to page 19 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain if the Fairmont 69kV project schedule has impacted the closeout of the Academy Street project. If so, please explain.	The Fairmount 69kV project has not impacted the close out of the Academy Street ES 2 project. The retired Academy Station is currently being demolished and close out of the ES 2 Academy Street project is pending completion of demolition.	No change
RCR-IM-13	With reference to page 21 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company is still experiencing resource availability issues that impact spending for the Leonia substation. If so, please explain what steps the Company is taking to address resource availability. If not, please explain what steps the Company took to resolve resource availability issues.	The resource availability issue resulted in an actual cost/forecast variance for the month of November 2021 and shifted the timing of planned work to future periods. This was a temporary issue and PSE&G has maintained the critical path on the project.	**Section III.A.7.**
RCR-IM-14	With reference to page 22 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the unplanned emergency work that impacted spending for the Market Street substation. Please indicate if the unplanned emergency work impacted other Energy Strong II projects.	The unplanned emergency work in that impacted the Market Street project related to unplanned storms and related events (Tropical Storm Elsa, Tropical Storm Henri, Hurricane Ida, emergency cable failures) that diverted internal resources from the Market Street project to perform restoration efforts. There were no impacts to other ES 2 projects and no other ES 2 projects utilized Southern Division resources in this period.	No change
RCR-IM-15	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain if the Company is experiencing higher than estimated traffic control requirements for other projects and if the Company is factoring increased traffic control requirements for future projects. If not, please explain why not.	Generally, PSE&G has not experienced higher than estimated traffic control requirements across the ES 2 Program, however higher traffic costs have been experienced on certain individual projects (e.g. Market Street) based on additional requirements required by the local municipality. PSE&G develops its traffic control estimates based on the amount of street work expected to be executed and the permit requirements for each location.	No change
RCR-IM-16	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please	PSE&G has recurring schedule review meetings on the project schedules to review the progress and identify possible opportunities for schedule	No change

ID #	Question/Comment	IM Response	Report Changes
	indicate if the Company has identified possible work activities and project schedule items to accelerate the scheduled completion date of the Orange Valley project. If so, please describe.	improvement through resequencing, running activities in parallel, or utilizing extra shifts. The schedule requirements are viewed holistically with the project costs, resource availability, and other relevant project data to provide an informed decision on how best to proceed. For Orange Valley, as of the end of the third quarter of 2022, the forecasted in-service date has slipped to 2/2/2024 due to equipment delivery delays being experienced that are pushing the project's critical path out.	
RCR-IM-17	With reference to page 23 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if any accelerated or compressed scheduling of the Orange Valley substation project would increase the current forecasted cost of $14.77 million. If so, please explain. If not, please explain why not.	Accelerating or compressing the schedule typically would add costs due to the extra resources/shifts required, which would somewhat be offset by lower carrying costs from the reduced project duration. The actual impacts would be dependent on the specific factors involved (e.g. how many extra shifts required, how much the schedule was compressed, etc.).	No change
RCR-IM-18	With reference to page 29 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please explain why the three reclosers in the Palisades Division require unique operating procedures. Please indicate if the Company has identified other recloser installations that have the same unique requirements. If so, please explain.	The three reclosers in the Palisades Division were to be installed with a unique operating procedure (in a single-phase operation) since the downstream load was primarily single-phase. With the unique operating procedure setting, only the 1 or 2 phases affected by a fault event will have an outage, not all three phases as would be the case with the standard operating procedure. No other reclosers have been identified for the unique operating procedure beyond these three in the Palisades Division. Ultimately, PSE&G installed these three reclosers following the standard operating procedure due to the time required to develop and implement a unique operating procedure. This will require the reclosers to be reprogrammed in the future from the standard operating procedure to the unique operating procedure, as of the end of October 2022, the reclosers are still using the standard operating procedure setting.	No change
RCR-IM-19	With reference to page 32 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the DMS/DERMS scope of work.	During the fourth quarter of 2022, PSE&G has been working on end-to-end testing with OSII on the DMS/DERMS scope as it prepares for operational readiness.	No change
RCR-IM-20	With reference to page 33 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the status of the ADMS Platform scope of work.	Following the ADMS Platform being placed in-service in December 2021, PSE&G has completed system acceptance testing and vulnerability testing, it has also completed deconstruction of the Edison Production rack and imaged workstations for the Divisions in preparation of training.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-21	With reference to page 35 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the condensation issues affecting the Paramus substation. Please indicate if the condensation issue is related to the design of the temporary feeder row or the result of construction activities.	The condensation was a result of the design of some of the rear panels on the contingency feeder rows as well as the settings on the heaters and humidifiers. The units which did not have vented panels experienced the condensation and when this was corrected, and the settings on the heaters and humidifiers were adjusted, the issue was resolved.	**Section III.E.2.**
RCR-IM-22	With reference to pages 35 and 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please describe the unknown underground obstruction affecting the Plainfield substation.	The unknown underground obstructions at Plainfield included existing below grade concrete structures and direct buried cables that were not included in the record drawings. The unknown underground obstructions resulted in marginal increases to engineering and construction costs.	**Section III.E.3.**
RCR-IM-23	With reference to page 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please provide an update on the material unavailability issue that impacted the Woodbury project.	The material unavailability issues involved perimeter wall foundations material delivery, which was delayed and pushed the construction of the wall foundation work from December 2021 to January 2022. This work was shifted with no impact to the project critical path and this issue was resolved as of January 2022.	**Section III.E.4.**
RCR-IM-24	With reference to page 36 of the Independent Monitor's Draft Fourth Quarter 2021 Report, please indicate if the Company is still experiencing material unavailability issues that impacted spending for the Woodbury substation. If so, please explain what steps the Company is taking to address material availability. If not, please explain what steps the Company took to resolve material availability issues.	This was a temporary issue. See the response to **RCR-IM 23**.	No change
Rate Counsel 10/11/2022 Letter	At the end of the fourth quarter 2021, the ESII program is slightly over 42 percent completed in spending. The Independent Monitor reports that electric spending for the quarter ending December 31, 2021 has been $43.946 million or 6.3 percent of the current forecast of $700.731 million electric ESII program (including the $100 million for Electric Stipulated Base). Rate Counsel notes that the parties stipulated to $842 million to complete the ES II Program with $641 million for electric, $50.5 million for gas, and $150.5 million within Stipulated Base for electric and gas spending.	The IM confirms this statement.	No change
Rate Counsel	Rate Counsel continues to note that the budget for Electric stipulated base has been set to $100 million	The IM confirms this statement.	No change

ID #	Question/Comment	IM Response	Report Changes
10/11/2022 Letter	for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the five substations (Hamilton, Paramus, Plainfield, Woodbury, and State Street). The current Study level estimate for the subprogram remains at $102.4 million including $19.6 million for risk and contingency.		
Rate Counsel 10/11/2022 Letter	The current forecast for the Electric Flood mitigation program increased slightly from $346.55 million in the Third Quarter Report to $347.842 million in the Fourth Quarter Report, including risk and contingency estimates. Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021, states that the base spending amount for the subprogram remains at $332.200 million in budgeted base project costs and $47.8 million allocated to risk and contingency.	The IM confirms this statement.	No change
Rate Counsel 10/11/2022 Letter	In the Fourth Quarter Report, the IM noted that PSE&G decreased its estimate for the Market Street substation by about $831,000. The IM noted that actual spending was below budgeted spending due to poor weather and resource constraints that included unplanned emergency work that pulled resources away from the project. Rate Counsel is interested in understanding if the Company has adequate resources to address ongoing work across the substations and address unforeseen situations.	PSE&G continuously works with its internal teams and its Divisions to coordinate schedules and allocate resources, including identifying the priority of different scopes of work. Unplanned outages and work related to ensuring the safety of the system are prioritized over standard project or routine work, but generally this type work is limited in duration so any impacts to the project schedules are similarly limited. PSE&G also utilizes contractor labor as appropriate. The IM also notes the forecast for Market Street decreased by approximately $831,000 during the fourth quarter of 2021, but the project estimate was not updated in this period.	No change
Rate Counsel 10/11/2022 Letter	In the Fourth Quarter Report, the IM noted that PSE&G has forecasted that the Orange Valley substation work is scheduled for completion on December 29, 2023 and that the Waverly substation project is scheduled for completion on September 17, 2024. The scheduled completion date for the Orange Valley substation is near the program end date of December 31, 2023, but the scheduled completion date for the Waverly substation is after the program end date. Rate Counsel is interested in	Since the end of the fourth quarter of 2021, the Waverly schedule has improved significantly based on better than expected timing of the permit approvals that improved the forecasted in-service date to February/March 2024 (see also the response to **RCR-IM-2**, **RCR-IM-7**, and **RCR-IM-9**). This reflects the final in-service date for transformer #3, while the 4kV switchgear and transformers #1-2 are forecasted to be in-service in December 2023. For the Orange Valley project, the most recent schedule data as of the end of the third quarter of 2022 indicates the forecasted in-service date has slipped into early February 2024.	No change

ID #	Question/Comment	IM Response	Report Changes
	understanding if PSE&G plans to accelerate work for both substations, and if accelerated work will impact current budgets for the two substations.	PSE&G continuously assesses the schedule and evaluates opportunities to advance the forecasted in-service date, primarily through resequencing activities or working activities in parallel. New information such as the actual status, updated durations, updated or completed engineering, and current permit or equipment receipt dates informs the current view of the schedule. Part of the schedule assessment also includes determining if it is appropriate to add resources, and if so, what cost impacts might be realized as a result. As both the Orange Valley and Waverly projects will be commencing construction (Phase 3 for Waverly) around the end of 2022/beginning of 2023, it is expected the schedule assumptions will be updated and through the recurring schedule reviews a determination will be reached on if the schedule can be advanced.	
PSEG-1	Under "Findings & Observations" for the Electric Station Flood Mitigation subprogram where the projects placed in-service are noted, the Leonia and Ridgefield 13kV projects achieved partial in-service during the fourth quarter of 2021.	The report finding has been updated to indicate the partial in-service status achieved by Leonia and Ridgefield 13kV.	**Section III.A.**
PSEG-2	Under Section III.A.7., it notes the Leonia switchgear #1 was placed in-service during the fourth quarter of 2021. The actual in-service date for this equipment was October 19, 2021.	The actual in-service date for Leonia's switchgear #1 has been added to the report.	**Section III.A.7.**
PSEG-3	Within the Executive Summary and repeated under "Findings & Observations" for the Grid Modernization – Communication System subprogram, the number of retrofit reclosers completed during the fourth quarter was 324, not 325.	The number of retrofit reclosers completed during the fourth quarter of 2021 has been corrected to 324.	**Sections I.** and **III.C.**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2022 FIRST QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

APRIL 17, 2022

Table of Contents

I. Executive Summary 1
II. Program Status 6
A. Key Decisions 6
B. Program Management 7
C. Cost Assignments 7
D. System Performance 13
III. Project Status 15
A. Electric Station Flood Mitigation 15
B. Contingency Reconfiguration 31
C. Grid Modernization – Communication System 33
D. Grid Modernization – ADMS 37
E. Electric Stipulated Base 39
F. Gas M&R Station Upgrades 43
IV. Additional Information Following the end of the First Quarter of 2022 47

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS

Allowance for Funds Used During Construction ..... AFUDC

Architect and Engineer ..... A/E

Board of Public Utilities ..... BPU

Construction Work In Progress ..... CWIP

Costs of Removal ..... COR

Distribution Management System ..... DMS

Distributed Energy Resource Management System ..... DERMS

Distribution Supervisory Control and Data Acquisition ..... DSCADA

Energy Strong 2 ..... ES 2

Gas Metering & Regulating ..... Gas M&R

Independent Monitor ..... IM

Inside Plant ..... IP

Issued for Construction ..... IFC

Issued for Review ..... IFR

Mobile Work Management System ..... MWMS

Open Systems International Inc. ..... OSII

Outage Management System ..... OMS

Outside Plant ..... OP

Outside Plant-Higher Design Standards ..... OP-HDS

Plain Old Telephone Service ..... POTS

Public Service Electric & Gas ..... PSE&G

Purchase Order ..... PO

Record of Decision ..... ROD

Remote Control Unit ..... RCU

Remote Terminal Unit ..... RTU

Risk and Contingency ..... R&C

Supervisory Control and Data Acquisition ..... SCADA

System Acceptance Testing ..... SAT

System Average Interruption Duration Index ..... SAIDI

Transmission & Distribution ..... T&D

Utility Review Board ..... URB

Virtual Private Network ..... VPN

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the first quarter of 2022.

During the first quarter of 2022, the bulk of the spend within the ES 2 Program continued to be in the largest subprogram, Electric Station Flood Mitigation, with two additional projects commencing construction during the quarter (Hasbrouck Heights and Woodlynne), and no additional projects being placed in-service (with Academy Street, Market Street, and Ridgefield 4kV previously being placed in-service). Within the other subprograms, the Contingency Reconfiguration subprogram completed the final batch of reclosers during the first quarter of 2022 and is now shifting to the Fuse Saver scope of work. The Grid Modernization – Communication System subprogram placed seven additional fiber installation projects and two additional fiber cutover projects in-service, with 27 fiber installation projects and 11 fiber cutover projects now completed in the ES 2 Program and the remaining projects expected to be completed by the end of 2022. The Grid Modernization – Communication System also continued to advance the retrofit substation remote terminal unit (RTU) scope, with the 75 additional substations completed, for a total of 85 completed as of the end of the first quarter of 2022 out of a forecasted scope of 218 substations. The Grid Modernization – ADMS subprogram completed sprints 14 and 15 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and sprints 12 and 13 within the Outage Management System (OMS) scope, while the ADMS Platform scope completed additional testing and prepared for Division training. The Gas M&R subprogram saw its highest quarterly spend to date on the ES 2 Program, which reflected three projects entering the construction phase (Camden, Central, and East Rutherford), while closeout and restoration activities continued on the Westampton project that was placed in-service during the fourth quarter of 2021. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the fourth quarter of 2021, while the State Street (Outside Plant, or "OP") project continued to advance the detailed engineering.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of March 31, 2022

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	**$18,695,029**	**$139,847,773**	**$349,562,560**	**40%**	**Mar 2024**	**$389M**

Subprogram	Q1 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Contingency Reconfiguration	**$2,277,408**	**$107,970,429**	**$145,273,272**	**74%**	**Nov 2023**	**$145M**
Grid Modernization – Communications	**$6,196,033**	**$54,561,042**	**$66,144,306**	**82%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$3,197,877**	**$29,536,156**	**$43,525,894**	**68%**	**Apr 2023**	**$42.7M**
Electric Stipulated Base	**$8,262,179**	**$26,317,199**	**$98,591,950**	**27%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$11,864,125**	**$32,040,114**	**$128,336,312**	**22%**	**Dec 2023**	**$101M**
Total*	**$50,492,652**	**$390,272,715**	**$831,434,293**	**47%**	**Mar 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending, a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of March 31, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,260,799	67%	**10/19/2021**
2. Clay Street	$30,800,000	$8,846,983	29%	1/30/2023 (↓+84)
3. Front Street^	$25,900,000	$2,781,438	11%	10/26/2023 (↑-21)
4. Hasbrouck Heights	$19,300,000	$9,779,630	51%	1/24/2023 (↑-8)
5. Kingsland	$6,400,000	$1,126,185	18%	10/2/2023 (↓+94)
6. Lakeside Avenue	$39,400,000	$1,525,371	4%	9/18/2023 (↑-51)
7. Leonia	$24,900,000	$16,979,539	69%	11/15/2022 (↓+6)
8. Market Street	$29,100,000	$27,820,378	96%	**6/25/2021**
9. Meadow Road	$7,200,000	$1,331,494	19%	9/22/2023
10. Orange Valley	$14,700,000	$909,541	6%	12/29/2023
11. Ridgefield 13kV	$26,100,000	$19,399,451	74%	12/13/2022 (↑-7)
12. Ridgefield 4kV	$20,800,000	$20,689,404	100%	**5/16/2021**
13. State Street	$19,600,000	$9,584,815	49%	12/19/2022 (↓+87)
14. Toney's Brook	$16,200,000	$1,664,826	10%	4/21/2023
15. Waverly	$36,200,000	$7,412,639	21%	3/5/2024 (↑-196)
16. Woodlynne	$21,300,000	$3,735,353	18%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover). **Bold dates indicate the actual in-service date.*

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
(↑)-*Indicates the forecasted in-service date advanced from the prior quarter in days.*				
(↓)-*Indicates the forecasted in-service date slipped from the prior quarter in days.*				
^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*				

As indicated in **Table 2**, the projects that previously started construction (including Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, State Street, and Waverly) continue to have the highest total spend to date. For the three projects placed in-service, Academy Street, Market Street, and Ridgefield 4kV, each were completed under their estimates. Additionally, PSE&G updated the base estimates to 10 of the 16 projects during the first quarter of 2022, with a net increase of $15.0 million, which also included the State Street and Hasbrouck Heights project estimates advancing to the Definitive stage.

Table 2 also shows that nine of the 16 projects had movement during the first quarter of 2022 in the forecasted in-service date, with five advancing and four slipping. Of these nine projects, four of the projects (Front Street, Hasbrouck Heights, Leonia, and Ridgefield 13kV) had forecasted in-service dates change by less than three weeks. As previously reported, the Waverly final in-service date was forecasted for September 2024, which had been a slight improvement from the previously forecasted December 2024 in-service date. Following the site plan approval in December 2021, PSE&G's team evaluated and updated the construction schedule, which allowed the in-service date to advance to March 2024 and continues to assess potential opportunities to advance the in-service date. The other largest shift to the forecasted in-service dates was the Kingsland project, which slipped 94 days from June 30, 2023 to October 2, 2023, and was driven by delays to the switchgear delivery on the Ridgefield 13kV project (as PSE&G intends to use the Ridgefield 13kV contingency switchgear on Kingsland). Major equipment deliveries constitute one of the largest current risks to the subprogram as further discussed in **Section III.A.** of this IM report.

While the subprogram forecast increased by approximately $1.7 million during the first quarter of 2022, it remains approximately $40 million under the Stipulation budget. The IM has continued to find nothing to date that would jeopardize the ES 2 Program being completed on budget. However, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date of December 2023 will continue to warrant further monitoring by the IM to confirm the ES 2 Program is completed within the defined timeline.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*
ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will

continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the first quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service.
    - Contingency Reconfiguration: Recloser scope completed with installation of final 23 units and commissioning of the remaining 25 units during the first quarter of 2022.
    - Grid Modernization – Communication System: 75 substation RTU retrofits completed (bringing the total to 85 out of a total scope of 218 substations); seven fiber installation projects were completed (bringing the total to 27); and two fiber cutover projects were completed (bringing the total to eleven out of a current scope of 12).
    - Electric Stipulated Base: Final circuit cutovers completed on the Paramus contingency switchgear.
    - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations planned to go in-service by the end of 2022.
- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of the first quarter of 2022 compared to the end of 2021 were as follows:
    - Electric Station Flood Mitigation: subprogram forecast increased approximately $1.7 million (or 0.5%) to approximately $349.6 million.
    - Contingency Reconfiguration: subprogram forecast decreased approximately $494,000 (or -0.3%) to approximately $145.3 million.
    - Grid Modernization – Communication System: subprogram forecast increased approximately $2.5 million (or 4.0%) to approximately $66.1 million.

- Grid Modernization – ADMS: subprogram forecast increased approximately $32,000 (or 0.1%) to approximately $43.5 million.
- Electric Stipulated Base: subprogram forecast decreased approximately $1.4 million (or -1.4%) to approximately $98.6 million.
- Gas M&R: subprogram forecast increased approximately $20.5 million (or 19.1%) to approximately $128.3 million.

As shown above, the biggest subprogram forecast changes during the first quarter of 2022 were in the Grid Modernization – Communication System, Electric Stipulated Base, and Gas M&R subprograms. Within the Grid Modernization – Communication System, the recent fiber projects have seen increased material and labor costs, while the Electric Stipulated Base projects saw slight forecast increases across all but the State Street OP project. Within the Gas M&R subprogram, the forecast growth includes the LPA components at certain projects that will be removed from the ES 2 project scope (which will also reduce the forecast accordingly).

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

  Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On February 13, 2022, a draft IM 2022 Fourth Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in

Appendix A – Draft Report Comments and Responses. This **Appendix A** also identifies specific sections within this IM 2022 First Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current RODs as of the date of this IM 2022 First Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**. During the first quarter of 2022, there were no additional RODs issued.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)*
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1.*

Subprogram	Record of Decision	IM Comments
		in the IM 2021 Second Quarter Report)
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

Early in 2022 PSE&G instituted a change in the way it manages the R&C for the Electric Station Flood Mitigation projects shifting from each project maintaining its own R&C funds to managing the R&C at the subprogram level. Prior to this shift, the projects' R&C was updated at the time of an estimate transition (50% to 70% to 90%). This change allows PSE&G to manage the R&C month-to-month based on the current project risk registers, which are updated monthly by the project team and reviewed by the subprogram lead. When the individual projects go through an estimate transition any variance to the base estimate results in additional funds added to the R&C placeholder (if the base estimate decreased) or release of R&C to cover the increase in base. Additionally, PSE&G's Utility Review Board (URB) continues to review and approve any estimate changes.

As part of the exercise in transitioning R&C from the project to the subprogram level, PSE&G also updated the base estimates for any Electric Station Flood Mitigation project that changed by more than $0.5 million (increasing or decreasing). Details of the updated estimates and the results of the shifting of R&C funds on the individual projects are discussed within **Section III.A.** and **Section III.E.**

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of March 31, 2022, below itemizes the charges to COR for the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 Program through March 31, 2022.

Table 4 – ES 2 Program Costs of Removal as of March 31, 2022

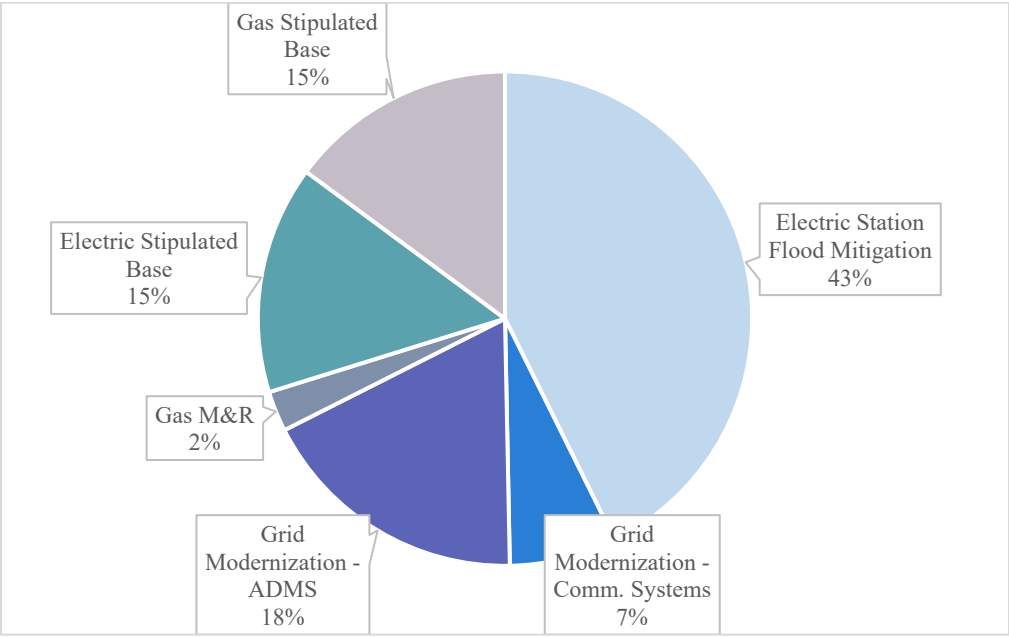
Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)					
Electric Station Flood Mitigation	**$873.4**	**$1,824.0**	**$5,558.7**	**$1,021.1**	**$0**	**$7,453.2**
Contingency Reconfiguration	**$229.3**	**$330.7**	**$2,250.2**	**$2,198.9**	**$431.0**	**$5,109.4**
Grid Modernization – Communications	**$11.0**	**$23.5**	**$137.8**	**$24.4**	**$0**	**$173.2**
Grid Modernization – ADMS	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Electric Stipulated Base	**$370.0**	**$146.8**	**$150.0**	**$0**	**$0**	**$520.0**
Gas M&R Station Upgrades	**($0.4)**	**($2.2)**	**$148.9**	**$0**	**$0**	**$148.5**
Gas Stipulated Base	**$431.5**	**$196.1**	**$196.1**	**$0**	**$0**	**$627.6**
Total	**$1,914.8**	**$2,518.9**	**$8,441.7**	**$3,244.4**	**$431.0**	**$14,031.9**

The COR charges for the first quarter of 2022 primarily reflect (i) approximately $0.7 million of COR activities at the Market Street substation elimination project, including demolition of the building and foundations, (ii) approximately $0.2 million related to partial removal of foundations at the Paramus lifecycle project, and (iii) approximately $0.4 million related to removal of certain concrete structures, such as a former tank pad, at the Central M&R station.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

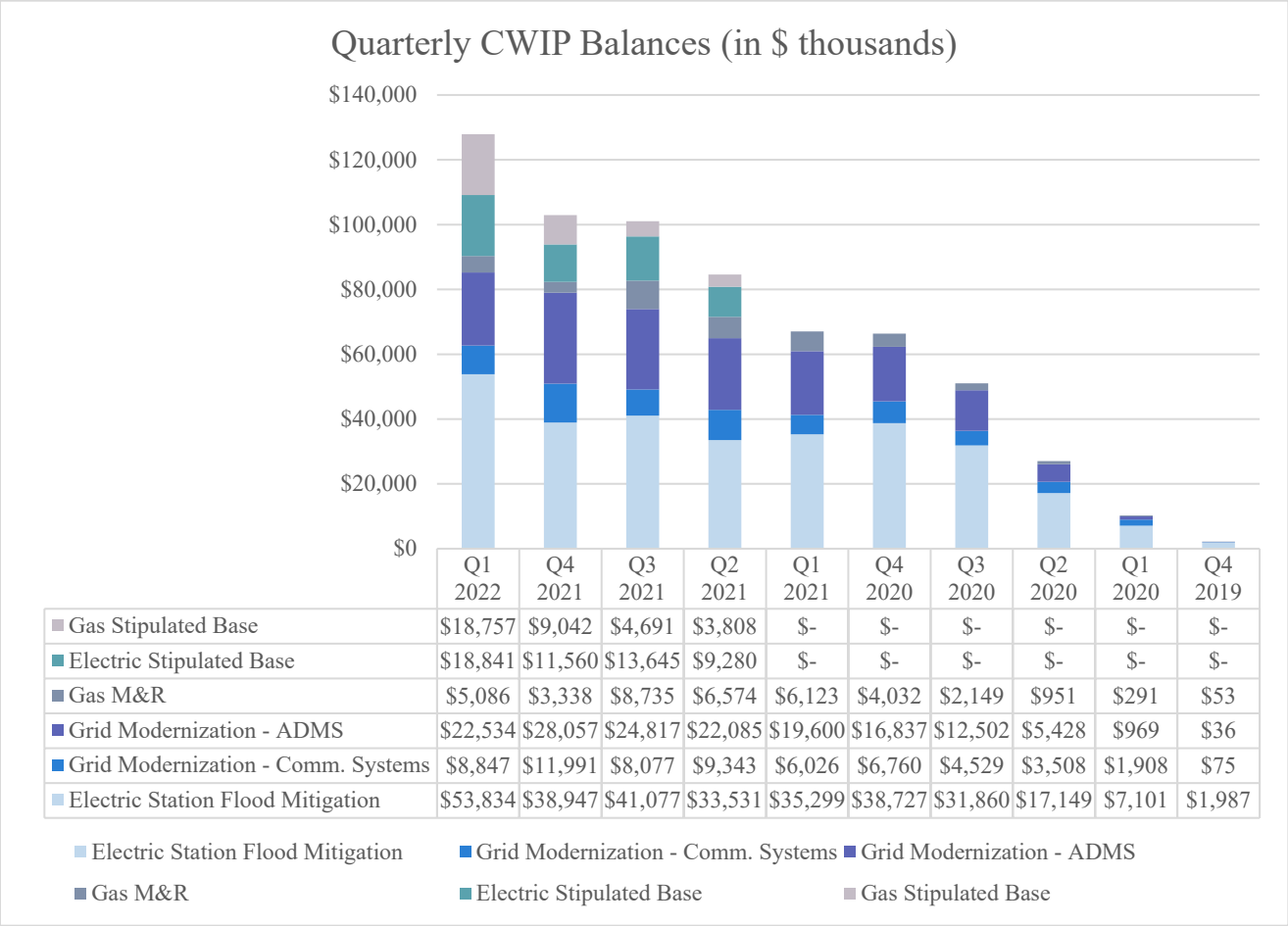
As of March 31, 2022, the ES 2 CWIP balance was $127.9 million, compared to $102.9 million as of December 31, 2021. The largest components of CWIP as of the end of the first quarter of 2022 were the Hasbrouck ($10.0 million), State Street ($9.9 million), Clay Street ($9.1 million), and Waverly ($7.9 million) Electric Station Flood Mitigation substation projects, the Central ($11.6 million) and Camden ($6.0 million) Gas M&R projects, the Hamilton ($7.4 million) and Plainfield ($5.3 million) substations Lifecycle projects, and work associated with the ADMS subprogram ($22.5 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of March 31, 2022** below.

Figure 1 – ES 2 CWIP as of March 31, 2022



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the first quarter of 2022, each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of March 31, 2022



	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Gas Stipulated Base	$18,757	$9,042	$4,691	$3,808	$-	$-	$-	$-	$-	$-
Electric Stipulated Base	$18,841	$11,560	$13,645	$9,280	$-	$-	$-	$-	$-	$-
Gas M&R	$5,086	$3,338	$8,735	$6,574	$6,123	$4,032	$2,149	$951	$291	$53
Grid Modernization - ADMS	$22,534	$28,057	$24,817	$22,085	$19,600	$16,837	$12,502	$5,428	$969	$36
Grid Modernization - Comm. Systems	$8,847	$11,991	$8,077	$9,343	$6,026	$6,760	$4,529	$3,508	$1,908	$75
Electric Station Flood Mitigation	$53,834	$38,947	$41,077	$33,531	$35,299	$38,727	$31,860	$17,149	$7,101	$1,987

Transfers from CWIP to plant in service totaled $15.1 million during the first quarter of 2022. During the first quarter of 2022, $6.6 million of Grid Modernization fiber projects were transferred to plant in service, as well as $8.4 million of assets associated with the ADMS subprogram. The ADMS assets transferred were hardware and software which were completed and successfully tested, and replaced the Company's legacy Distribution Supervisory Control and Data Acquisition (DSCADA) system, which was at the end of its lifecycle. Total ES 2 transfers from CWIP have been $85.9 million through March 31, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no allowance for funds used during construction (AFUDC) is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for the ES 2 subprogram during the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total AFUDC for the years 2021, 2020, and 2019, and total ES 2 Program AFUDC accrued through the end of 2021, is shown below **Table 5 – ES 2 Program AFUDC as of March 31, 2022**.

Table 5 – ES 2 Program AFUDC as of March 31, 2022

Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)					
Electric Station Flood Mitigation	**$759.0**	**$564.3**	**$2,281.2**	**$936.5**	**$9.9**	**$3,986.6**
Contingency Reconfiguration	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grid Modernization – Communications	**$115.6**	**$127.2**	**$386.9**	**$184.3**	**$0.2**	**$687.0**
Grid Modernization – ADMS	**$385.7**	**$411.0**	**$1,365.6**	**$352.7**	**$0.1**	**$2,104.1**
Electric Stipulated Base	**$230.0**	**$233.6**	**$524.6**	**$44.0**	**$0**	**$798.6**
Gas M&R Station Upgrades (incl. Stip. Base)	**$208.3**	**$133.2**	**$470.0**	**$70.0**	**$0.2**	**$748.5**
Total	**$1,698.6**	**$1,469.3**	**$5,028.3**	**$1,587.5**	**$10.4**	**$8,324.8**

AFUDC accrued for ES 2 projects during the first quarter of 2022 increased over AFUDC accrued during the fourth quarter of 2021 primarily as the result of increases in total average CWIP balances, especially for the Electric Station Flood Mitigation and Gas M&R/Gas Stipulated Base projects.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the first quarter of 2022, based on data as of March 31, 2022, the recalculated weighted average AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the first quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Energy Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to ES 2 project costs in the first quarter of 2022 is consistent with the applicable dictates of the Stipulation entered into with respect to these ES 2 projects. The IM will continue to review future ES 2 Program AFUDC accruals for

consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003 as updated in September 2022. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of March 31, 2022** are the allocated overhead costs charged to ES 2 projects for the first quarter of 2022, the fourth quarter of 2021 (for comparative purposes), total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of March 31, 2022

Subprogram	Q1 2022	Q4 2021	Total 2021	Total 2020	Total 2019 (Q4)	Total to Date
	(in $ thousands)					
Electric Station Flood Mitigation	**$2,185**	**$1,902**	**$14,368**	**$14,023**	**$287**	**$30,863**
Contingency Reconfiguration	**$843**	**$2,516**	**$14,420**	**$17,109**	**$3,415**	**$35,787**
Grid Modernization – Communications	**$1,802**	**$2,692**	**$9,171**	**$3,625**	**$12**	**$14,610**
Grid Modernization – ADMS	**$76**	**$133**	**$501**	**$426**	**$11**	**$1,014**
Electric Stipulated Base	**$1,449**	**$807**	**$2,123**	**$259**	**$0**	**$3,832**
Gas M&R Station Upgrades (incl. Stip. Base)	**$197**	**$250**	**$735**	**$291**	**$15**	**$1,238**
Total	**$6,552**	**$8,300**	**$41,318**	**$35,733**	**$3,740**	**$87,344**

The overwhelming majority of overhead costs allocated to ES 2 projects during the first quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 77%) of the 2022 first quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overhead costs for the first quarter of 2022 from the fourth quarter 2021 reflects the completion of recloser scope of work in the Contingency Reconfiguration subprogram early in the first quarter of 2022 and completion of the Grid Modernization recloser retrofit scope in the fourth quarter of 2021.

D. System Performance

1. Current Reporting Quarter Major Events

During the first quarter of 2022, there were two Major Events reported in PSE&G's service territory, each involving a State of Emergency related to snowstorms experienced in the region.

The first one occurred from January 6-12, 2022, and saw 11,999 PSE&G customers experience service interruptions, while the second State of Emergency occurred from January 28-February 4, 2022, and saw 40,277 PSE&G customers experience service interruptions. Between these two storms, neither brought flooding issues to PSE&G substations or switching stations.

The IM has received PSE&G's report on the performance of its investments from these Major Events and has reproduced the results in **Table 7 – Q1 2022 Major Event Performance** below.

Table 7 – Q1 2022 Major Event Performance

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
ADA 8012	0.02574	0.00083
ALD 8012	0.37227	0.00059
ALD 8022	0.05448	0.00096
BEN 8011	**0.00163**	**0.02166**
BLO 4009		**0.03680**
BUS 8012	0.04422	0.00000
CED 8011	0.05594	0.00475
CED 8016	0.07119	0.00659
CIN 8009	0.14835	0.00089
CIN 8043	0.18459	0.00010
CLF 8015	**0.01520**	**0.06820**
CLK 8014	0.20056	0.00951
CLK 8023	0.00019	0.00000
CLK 8024	0.01526	0.00000
CLK 8042	0.35206	0.00033
COR 8042	0.05446	0.00000
CRX 8008	0.24596	0.00065
CUT 8004	0.18618	0.00071
CUT 8033	0.02286	0.00000
DEA 4009		**0.00043**
DOR 8012		**0.01776**
DOR 8015	0.02588	0.00153
EAT 8023		**0.04074**
FAW 8016	0.12332	0.01109
FAW 8023	0.02811	0.00060
FOR 4009		**0.00738**
FRA 8011		0.00000
GBK 8021	0.06208	0.00000
HID 8034	0.25737	0.00000
HOE 8037	**0.00573**	**0.02260**
HOE 8047	0.05561	0.01624
JAC 8022	0.04453	0.01036

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
JAC 8023	0.05394	0.00221
JAC 8033	0.00350	0.00266
KIL 8012	0.21603	0.00000
KIL 8034	0.44870	0.00016
KIN 8011		**0.01061**
KIN 8014	0.00171	0.00031
KUS 8034	0.01739	0.00047
KUS 8045	0.02505	0.00000
LAF 8013	0.00125	0.00000
LAU 8011	0.30809	0.00157
LAU 8021	0.44101	0.00206
LAU 8025	0.02009	0.01377
LAU 8035	0.29567	0.00000
LAW 8023	0.01733	0.00049
LCE 8033	0.42672	0.00964
LEO 8004	**0.00027**	**0.03249**
LEO 8005	0.61152	0.00654
LEO 8042		0.00000
LEO 8043	0.07891	0.00037
LEV 8008	0.04412	0.00082
LEV 8016	**0.00021**	**0.00245**
LIT 8001	0.02586	0.01920
LUM 8014	0.29932	0.00000
MAD 8018	0.20763	0.00000
MAR 8002	0.04356	0.00220
MAR 8004	0.02404	0.00603
MAR 8013	0.36502	0.00000
MAY 8024	0.00558	0.00119
MCL 4008		0.00145
MEA 8021	0.06020	0.00000
MRO 8012	1.08732	0.00008
MRO 8013	0.46710	0.00000

Circuit	5 Year Baseline SAIDI*	Report Quarter SAIDI*
MTL 8013	0.02134	0.00000
MTL 8014	0.00035	0.00000
NED 8016	0.00729	0.00504
NEW 8025	0.00343	0.00000
NEW 8041	**0.00280**	**0.00550**
NEW 8042	0.05837	0.03241
NOT 8022	**0.00091**	**0.02638**
PEH 8004		**0.00053**
PIE 8013	0.02355	0.00465
PIE 8022		**0.00490**
POH 8015	0.12765	0.00000
RFL 8011	0.00742	0.00522
RFL 8012	**0.00235**	**0.03403**
SAD 8002		**0.00270**
SAD 8032		**0.01434**
SDH 8023	0.00860	0.00530
SDH 8026	0.01685	0.00003
SDH 8031	**0.01726**	**0.03019**
SMV 8011	0.00774	0.00231
SMV 8014	0.06467	0.00549
SMV 8023	0.01943	0.00089
SOH 8022	0.16946	0.00000
SOS 8015	0.19304	0.02441
SPF 8014		**0.03536**
SPF 8016		**0.00078**
STP 8002	0.02921	0.01204
SUN 8013		0.00000
WAN 8014		0.00000
WAN 8015		**0.00056**
WAV 4004	0.09979	0.02798
WEW 8021	0.21824	0.00000
WEW 8042	0.01304	0.00163
WEW 8044	0.07375	0.00203
WFL 8034	0.04228	0.00690
WOR 8037	0.00017	0.00000
WOR 8039	0.18307	0.00068

**-Calculated in minutes.*

In the circuit data in **Table 7** above, the "0.00000" indicates an outage, but the value is beyond five decimal points captured by PSE&G, while blank cells indicate no outage in the 5-year window. Additionally, all circuits impacted by this Major Event had received investments during either the original Energy Strong Program or through ES 2. As indicated above, there were 100 circuits impacted by these two Major Events, 73 of which had a current Major Event System Average Interruption Duration Index (SAIDI) better than the 5-year Major Event SAIDI average, while 18 circuits had no Major Event outage within the 5-year comparison window, leaving nine circuits that both had a prior Major Event outage within the past 5-years and had worse performance during these Major Events.

Additional information on the nine circuits that had worse performance during these Major Events than the 5-year Major Event SAIDI average is provided below in **Table 8 – Q1 2022 Major Event Additional Information on Selected Circuits** (note that some of these circuits had more than one incident during the Major Event, resulting in a total of 17 incidents from these nine circuits).

Table 8 – Q1 2022 Major Event Additional Information on Selected Circuits

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
BEN 8021	0.00163	0.02166	673	80
CLF 8015	0.01520	0.06820	1,156	108
CLF 8015	0.01520	0.06820	324	138
HOE 8037	0.00573	0.02260	133	413
HOE 8037	0.00573	0.02260	1	1,250
LEO 8004	0.00027	0.03249	1,224	66
LEV 8016	0.00021	0.00245	610	10
NEW 8041	0.00280	0.00550	253	29
NEW 8041	0.00280	0.00550	253	25
NOT 8022	0.00091	0.02638	305	193

Circuit	5-Year Baseline SAIDI*	Report Quarter SAIDI*	Customers Impacted	Outage Duration*
NOT 8022	0.00091	0.02638	6	516
NOT 8022	0.00091	0.02638	4	516
NOT 8022	0.00091	0.02638	3	516
RFL 8012	0.00235	0.03403	1,880	45
SDH 8031	0.01726	0.03019	480	79
SDH 8031	0.01726	0.03019	384	79
SDH 8031	0.01726	0.03019	453	15
**-Calculated in minutes.*				

As indicated in **Table 8**, in addition to the original Energy Strong Program and ES 2 investments that increased sectionalizing of circuits to reduce the number of customers impacted by outages, the customer impact from a Major Event is also a function of the nature of the outages (extent of damage) and the location of damage relative to the various interrupting devices on the circuit, that is, reclosers or fuses. For some circuits, the 5-year baseline outage(s) were smaller or affected fewer customers, including different device operations (fuse with 10 customers vs. fuse with 150 customers) than the incident from the current Major Event being reported. Some circuits had more non-reclosing device operations in this Major Event (more fuse jobs) or more customers served by the circuit due to circuit rearrangements. Additionally, the circuits in **Table 8** with zero customers reflect the way the circuit is modeled in PSE&G's connectivity model and the restoration/isolation steps used to restore service (e.g. isolating a section of cable for repair, or a transformer with no assigned customers). The cause of the individual circuit incidents also varied, with some related to spacer cable issues (CLF 8015), some related to transformer failures (HOE 8037), some related to vegetation issues (LEV 8016 and NEW 8041), and some related to broken or damaged poles (NEW 8041 and NOT 8022).

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the first quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 9 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of March 31, 2022**. Note that the Market Street and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 9**).

Table 9 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of March 31, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C									CO						
	Dec. 2021		KO		C						IS						CO			
	Mar. 2022		KO		C						IS						CO			
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C					IS				CO (Q2)
	Dec. 2021			KO							C				IS					CO (Q1)
	Mar. 2022			KO							C					IS				CO (Q1)

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Dec. 2021								KO				C						IS	CO (Q2)
	Mar. 2022								KO				C						IS	CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
	Mar. 2022		KO									C				IS		CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	
	Mar. 2022			KO											C				IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
	Mar. 2022						KO							C				IS		CO (Q1)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
	Mar. 2022			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
	Mar. 2022			KO										C				IS		CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Mar. 2022					KO										C			IS	CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Mar. 2022			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
	Mar. 2022		KO						C						IS		CO			
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C			IS			CO (Q2)
	Mar. 2022			KO										C			IS			CO (Q2)

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
	Mar. 2022			KO			C													IS (Q1); CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)
	Mar. 2022		KO								C								IS	CO (Q2)

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the first quarter of 2022 is provided below in **Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2022**.

Table 10 – ES 2 Electric Station Flood Mitigation Summary Status as of March 31, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	10	Academy Street; Clay Street; Hasbrouck Heights; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

Activity	Total # of Projects	Specific Projects
-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.* *[1]-Indicates Burns & McDonnell is serving as the A/E.* *[2]-Indicates PSE&G internal resources are serving as the A/E.* *[3]-Indicates Black & Veatch is serving as the A/E.* *-Includes inside plant (IP) and/or outside plant (OP) construction.*		

Beyond the key activities summarized in **Table 10** above, **Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022** summarizes the upcoming planned activities for each project during the second quarter of 2022, including any carryover of activities from earlier periods.

Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022

Station	Upcoming Activities for Q2 2022	Carryover Activities from Q1 2022
1. Academy Street	• Complete closeout report • Demo existing foundations, remove old equipment at existing Academy St. station	• Continue civil and electrical construction • Continue circuit cutovers
2. Clay Street	• Commence pile driving	• Major municipal licenses and permits issuance
3. Front Street	• Civil drawings Issued for Construction (IFC) • Civil and electrical POs issued • Start civil construction	• Continue engineering
4. Hasbrouck Heights	• Start civil foundations • Start electrical construction	• Continue civil construction
5. Kingsland	• Civil and electrical construction out for bid	• Continue engineering
6. Lakeside Avenue	• Civil PO issued • Major state licenses and permits issued	• Continue engineering
7. Leonia	• Complete demo of existing feeder rows • Receive switchgear #2 • Switchgear #2 circuits cutover to temporary switchgear	• Continue civil and electrical construction
8. Market Street	• Complete demolition and site remediation	• Continue demolition
9. Meadow Road	• Civil, controls, and electrical drawings IFC • Transition to 70% estimate	• Continue engineering
10. Orange Valley	• Controls drawings Issued for Review (IFR) • Civil and electrical drawings IFC • Site plan memorialization • Civil and electrical construction out for bid	• Continue engineering
11. Ridgefield 13kV	• Complete circuit cutovers to new switchgear #2 • Compete circuit cutovers from existing switchgear #1 to temporary switchgear • Demo existing switchgear #1	• Continue construction
12. Ridgefield 4kV	• Project complete	• Project complete
13. State Street	• Start civil foundations	• Continue construction
14. Toney's Brook	• Continue engineering	• Continue engineering
15. Waverly	• Receive phase 2 permits and hold pre-construction review with contractor • Start phase 2 civil and electrical construction • Set 26kV switchgear and commence commissioning	• Continue construction

Station	Upcoming Activities for Q2 2022	Carryover Activities from Q1 2022
16. Woodlynne	• Continue engineering	• Continue engineering

During the first quarter of 2022, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the major equipment deliveries may be impacted beyond the delay previously identified to the Ridgefield 13kV switchgear. As of the end of the first quarter of 2022, Powercon advised PSE&G that delivery delays were now expected for the Hamilton switchgear (delayed two months) and the Clay Street regulators (delayed five months), while also possible for equipment on the Paramus, Plainfield, Toney's Brook, Woodbury, and Woodlynne projects.[1] PSE&G was able to re-sequence the Hamilton schedule to mitigate the majority of this delay impact, while the Clay Street equipment was scheduled to be stored and has no schedule impact as a result at this time.

PSE&G receives weekly updates from Powercon on the current status of the deliveries, has initiated status calls to inquire further information on the current status, and has conducted site visits to gain further awareness on the status of this equipment. The overall status remains fluid, based on the current information from Powercon and this issue continues to be managed beyond the first quarter of 2022, but PSE&G has generally been able to mitigate any project impacts either from having the initial ship dates in advance of the project need dates, thereby building in float to the schedule, or by resequencing activities. One current exception is the Kingsland project, which saw its in-service date slip 94 days from June 30, 2023 to October 2, 2023 due to delays in the 13kV switchgear delivery on the Ridgefield 13kV project (for cost efficiencies, PSE&G plans to use the contingency switchgear from the Ridgefield 13kV project on Kingsland, which saves an estimated $1.7 million compared to if this option had not been available and is also the same approach that was used for the Meadow Road contingency switchgear that will serve as the permanent switchgear on Leonia).

The current project estimates are shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022**. As discussed in **Section II.B.**, during the first quarter of 2022, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the first quarter of 2022.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$8,698,421	$6,260,799	67%
2. Clay Street	Conceptual	$30,800,000	$-	$30,800,000	$31,302,000	$8,846,983	29%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$25,693,360	$2,781,438	11%

[1] The Hamilton, Paramus, Plainfield, and Woodbury projects are all within the Electric Stipulated Base scope of the ES 2 Program.

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$19,027,836	$9,779,630	51%
5. Kingsland	Study	$6,400,000	$-	$6,400,000	$6,427,155	$1,126,185	18%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$36,697,209	$1,525,371	4%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$24,952,795	$16,979,539	68%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,235,161	$27,820,378	96%
9. Meadow Road	Study	$7,200,000	$-	$7,200,000	$7,782,150	$1,331,494	19%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$14,742,882	$909,541	6%
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$27,245,211	$19,399,451	74%
12. Ridgefield 4kV	Definitive	$20,800,000	$-	$20,800,000	$20,707,403	$20,689,404	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,837,904	$9,584,815	49%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,254,329	$1,664,826	10%
15. Waverly	Study	$36,200,000	$-	$36,200,000	$37,648,812	$7,412,639	21%
16. Woodlynne	Study	$21,300,000	$-	$21,300,000	$24,310,000	$3,735,353	18%
ES 2 Station Placeholder	N/A	$-	$41,800,000	$41,800,000	$-	$-	-
Subprogram Total		**$347,200,000**	**$41,800,000**	**$389,000,000**	**$349,562,629**	**$139,847,775**	**36%**

-As discussed in **Section II.B., during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- Nine of the sixteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the first quarter of 2022, with five advancing and four slipping. The biggest changes came on the following projects:

- Waverly (advancing 196 days from September 17, 2024 to March 5, 2024), driven by improvements in the construction schedule following the site plan approval in December 2021;
- Kingsland (slipping 94 days from June 30, 2023 to October 2, 2023), driven by delays to the 13kV switchgear delivery on the Ridgefield 13kV project (Kingsland plans to use the contingency switchgear from the Ridgefield 13kV project), which effectively reversed the 96 day schedule advancement reported in the fourth quarter of 2022;
- State Street (slipping 87 days from September 23, 2022 to December 19, 2022), driven by an updated Southern Division OP schedule for when the first circuit will be ready for energization, which is a prerequisite to place the IP substation assets in-service;
- Clay Street (slipping 84 days from November 7, 2022 to January 30, 2023), driven by delays in securing the above grade structures and electric construction permits; and
- Lakeside Avenue (advancing 51 days from November 8, 2023 to September 18, 2023), driven by updates to the construction schedule that allowed installation of the switchgear foundation to commence in 2022 instead of 2023.

The forecasted in-service date shifts to the other four projects (Front Street, Hasbrouck Heights, Leonia, and Ridgefield 13kV) were between six days and 21 days and reflective of actual project conditions experienced in the first quarter of 2022.

- No change in completed projects during the first quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next project forecasted to be placed in-service are the Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service during the fourth quarter of 2022.
- In conjunction with the change how the projects' R&C on the subprogram is managed (shifting from project-level to subprogram-level), PSE&G also updated the base project estimates for the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage). Collectively these changes in base estimates resulted in a $15.0 million increase (with $12.3 million of that increase attributed to the Waverly ($6.8 million) and Woodlynne ($5.5 million) projects).
- The overall subprogram forecast as of the end of the first quarter of 2022 increased $1.7 million (or 0.5%) to $349.6 million from the status as of the end of 2021. The forecast continues to remain under the current subprogram estimate of $389.0 million (which includes $41.8 million of contingency and also matches the Stipulation amount of $389.0 million).
- With 40% of the subprogram forecast now spent (36% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget. However, the status of the later projects in this subprogram, and in particular Waverly, will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. Other projects currently forecasted to be in-service in the final quarter of the Program (fourth quarter of 2023) include: Front Street, Kingsland, Orange Valley, and Woodlynne.

- Relative to the Waverly project, as of the end of the first quarter of 2022, the project continues to show a final in-service date in 2024, now at March 2024, which has advanced as PSE&G details the schedule following the site plan approval in December 2021. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to March 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM will continue to review the proposed actions by PSE&G and report on the status in future IM quarterly reports,

1. Academy Street

During the first quarter of 2022, $131,061 was spent on the Academy Street project compared to a forecast of approximately $159,000, which brought the total spend to approximately $6.3 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Academy Street estimate was revised with the base estimate decreasing from $9.8 million to $9.3 million, which was the result of efficiencies gained in the construction and commissioning activities.

This project was placed in-service on October 19, 2021, and there were minimal activities performed during the first quarter of 2022 other than the continued circuit cutovers. The elimination of equipment at the old substation site and related demolition activities are expected to commence in the second quarter of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023+
Actuals				*Forecast*			
$150,398	$4,224,550	$1,754,789	$131,061	$185,615	$206,354	$2,045,653	$-

Actuals to Date	Estimate	% of Actuals to Estimate
$6,260,799	$9,300,000	67%

2. Clay Street

During the first quarter of 2022, $5,044,642 was spent on the Clay Street project compared to a forecast of approximately $4.9 million, which brought the total spend to approximately $8.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Clay Street estimate was revised with the base estimate increasing from $30.3 million to $30.8 million, which was the result of the change in Transmission & Distribution (T&D) surcharge methodology. The current forecast of $31.3 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically an additional $0.5 million over the current estimate based on additional civil work required (e.g. enlarging two manholes, extra shifts).

The forecasted in-service date for the Clay Street project as of the end of the first quarter of 2022 slipped 84 days from the status as of the end of 2021. This shift was the result of delays in securing the above grade structures and electrical construction permits and eliminates the advancement in the forecasted in-service date gained during the fourth quarter of 2021.

The primary activities on the Clay Street project during the first quarter of 2022 included the submittal of the below grade permit package and the partial delivery of the switchgear (with the regulators expected to be delivered in May 2022).

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$116,409	$879,339	$2,806,593	$5,044,642	$5,964,696	$5,553,877	$5,147,098	$5,789,346

Actuals to Date	Estimate	% of Actuals to Estimate
$8,846,983	$30,800,000	29%

3. Front Street

During the first quarter of 2022, $429,607 was spent on the Front Street project compared to a forecast of approximately $465,000, which brought total spend to approximately $2.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Front Street estimate was revised with the base estimate increasing from $23.0 million to $25.9 million, which was the result of higher than estimated switchgear award ($2.1 million), higher than previously estimated construction supervision costs ($0.5 million), and utilizing an external A/E firm rather than in-house engineering as initially planned ($0.3 million). The switchgear was competitively bid and was awarded to the same vendor that was previously awarded the switchgear for other projects in the Program, suggesting current market conditions have contributed to the cost growth. Additionally, concerning the switch to an external A/E firm, PSE&G determined it did not have the internal resources to support the project schedule, thus after preliminary engineering was complete, it outsourced the detailed engineering scope.

The forecasted in-service date for the Front Street project as of the end of the first quarter of 2022 advanced 21 days from the status as of the end of 2021 to October 26, 2023.

The primary activities on the Front Street project during the first quarter of 2022 included:

- The continuation of the civil construction that commenced late in 2021;
- The receipt of the Soil Conservation District permit; and,
- Civil and electrical drawings IFR, and the civil and electrical contingency drawings IFC.

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$-	$-	$2,351,832	$429,607	$785,609	$4,512,621	$1,982,573	$15,631,119

Actuals to Date	Estimate	% of Actuals to Estimate
$2,781,438	$25,900,000	11%

4. Hasbrouck Heights

During the first quarter of 2022, $4,323,599 was spent on the Hasbrouck Heights project compared to a forecast of approximately $4.5 million, which brought the total spend to approximately $9.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Hasbrouck Heights estimate advanced to the Definitive stage with a $1.2 million reduction to the base estimate (while the R&C was removed as discussed above), for a new estimate of $19.3 million. The total forecast for the Hasbrouck Heights project decreased approximately $1.4 million from the prior quarter for a current forecast of $19.0 million. The decrease was driven by lower than previously estimated dewatering costs based on soil conditions in the specific construction area.

The forecasted in-service date for the Hasbrouck Heights project as of the end of the first quarter of 2022 advanced eight days from the status as of the end of 2021 to January 24, 2023.

Notable activities completed during the first quarter of 2022 included:

- The delivery of regulator sections to complete the switchgear delivery;
- The pre-construction licensing and permitting compliance and construction requirements review with the contractor; and,
- Commencement of civil construction and demolition of the existing control house.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,141,254	$1,588,496	$2,148,686	$3,369,770

Actuals to Date	Estimate	% of Actuals to Estimate
$9,779,630	$19,300,000	51%

5. Kingsland

During the first quarter of 2022, $301,463 was spent on the Kingsland project compared to a forecast of approximately $291,000, which brought the total spend to approximately $1.1 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Kingsland estimate was revised with the base estimate increasing from $5.4 million to $6.4 million, which was the result of the change in T&D surcharge methodology.

The forecasted in-service date for the Kingsland project as of the end of the first quarter of 2022 slipped 94 days from the status as of the end of 2021 to October 2, 2023. This was driven by the delay to the 13kV switchgear delivery on the Ridgefield 13kV project as the Kingsland project plans to use the contingency switchgear from the Ridgefield 13kV project. This shift in the forecasted in-service date reverses the 96-day advancement gained during the fourth quarter of 2021.

During the first quarter of 2022, primary activity on the Kingsland project was the site plan submittal.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$104,112	$209,667	$510,943	$301,463	$159,197	$147,083	$1,079,078	$3,915,613

Actuals to Date	Estimate	% of Actuals to Estimate
$1,126,185	$6,400,000	18%

6. Lakeside Avenue

During the first quarter of 2022, $351,720 was spent on the Lakeside Avenue project compared to a forecast of approximately $312,000. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Lakeside Avenue estimate was revised with no change to the base estimate (while the R&C was removed as discussed above). The total forecast for the Lakeside Avenue project decreased approximately $2.7 million from the prior quarter for a current forecast of $36.7 million. The decrease was driven by the civil construction bid being lower than previously estimated.

The forecasted in-service date for the Lakeside Avenue project as of the end of the first quarter of 2022 advanced 51 days from the status as of the end of 2021. This change was driven by an updated construction schedule that supported the commencement of the installation of the switchgear foundation in 2022 instead of 2023 as earlier planned, which allowed the in-service date to advance from November 2023 to September 2023.

Notable activities completed during the first quarter of 2022 included the IFC release of civil and electrical drawings, constructability reviews of the IP controls design drawing, and civil construction work out for bid.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$148,943	$453,994	$570,713	$351,720	$433,537	$851,140	$312,218	$33,574,943

Actuals to Date	Estimate	% of Actuals to Estimate
$1,525,371	$39,400,000	4%

7. Leonia

During the first quarter of 2022, $1,789,112 was spent on the Leonia project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $17.0 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Leonia estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Leonia project as of the end of the first quarter of 2022 slipped six days from the status at the end of 2021.

Notable activities completed during the first quarter of 2022 included finishing the circuit cutovers on the 13kV switchgear #1 (which was placed in-service at the end of 2021) and the start of circuit cutovers from the existing switchgear #2 to the temporary switchgear.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,939,075	$1,119,964	$1,415,109	$1,499,108

Actuals to Date	Estimate	% of Actuals to Estimate
$16,979,539	$24,900,000	68%

8. Market Street

During the first quarter of 2022, $808,096 was spent on the Market Street project compared to a forecast of approximately $976,000, which brought the total spend to approximately $27.8 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Market Street estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

Notable activities conducted during the first quarter of 2022 included the receipt of the building demolition permit and the commencement of the building demolition. Demolition and site remediation activities are expected to be completed during the second quarter of 2022.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$251,193	$16,079,601	$10,681,487	$808,096	$325,784	$47,000	$42,000	$-

Actuals to Date	Estimate	% of Actuals to Estimate
$27,820,378	$29,100,00	96%

9. Meadow Road

During the first quarter of 2022, $288,050 was spent on the Meadow Road project compared to a forecast of $226,000, which brought the total spend to approximately $1.3 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Meadow Road estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Meadow Road project as of the end of the first quarter of 2022 remained unchanged from the status as of the end of 2021 at September 22, 2023.

The primary activity during the first quarter of 2022 was the continued advancement on detailed engineering, which commenced during the fourth quarter of 2021.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$63,128	$535,081	$445,234	$288,050	$141,114	$410,445	$1,365,600	$4,533,498

Actuals to Date	Estimate	% of Actuals to Estimate
$1,331,494	$7,200,000	19%

10. Orange Valley

During the first quarter of 2022, $111,565 was spent on the Orange Valley project compared to a forecast of approximately $116,000, which bought the total spend to approximately $910,000. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Orange Valley estimate was revised with the base estimate decreasing from $16.0 million to $14.7 million. This decrease to the base estimate was driven by lower than estimated A/E award (-$0.5 million, revised 4kV equipment relocation estimate from the Division (-$0.5 million), lower than estimated switchgear award ($-0.2 million), and lower carrying cost (-$0.1 million).

The forecasted in-service date for the Orange Valley project as of the end of the first quarter of 2022 remained unchanged from the status as of the end of 2021 at December 29, 2023.

During the first quarter of 2022, major activities on the Orange Valley project included the DEP permit submission, the IFR release of civil and electrical drawings, and constructability reviews of the civil and electrical design drawings.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$77,029	$362,895	$358,052	$111,565	$254,365	$173,034	$115,980	$13,289,963

Actuals to Date	Estimate	% of Actuals to Estimate
$909,541	$14,700,000	6%

11. Ridgefield 13kV

During the first quarter of 2022, $2,111,096 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.15 million, which brought the total spend to approximately $19.4 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Ridgefield 13kV estimate was revised as the project transitioned to the definitive estimate phase with the base estimate increasing by $0.8 million to $26.1 million. This increase in the base estimate was driven by required rebuilds of two additional manholes and more Division underground labor required for cable pulling and cutovers. The current forecast of $27.2 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- More than anticipated dewatering and updated design of manhole modifications ($0.5 million); and,
- More Division effort required on manhole expansion and circuits cutovers due to difficulty of breaking back the duct bank (high strength concrete) and working around the energized circuits ($0.6 million).

The forecasted in-service date for the Ridgefield 13kV project as of the end of the first quarter of 2022 advanced seven days from the status as of the end of 2021 to December 13, 2022.

Notable activities completed during the first quarter of 2022 included the continued manhole modifications and circuit cutovers to the new switchgear #2.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$205,982	$6,232,692	$10,849,681	$2,111,096	$3,943,529	$1,655,900	$1,442,330	$804,000

Actuals to Date	Estimate	% of Actuals to Estimate
$19,399,451	$26,100,000	67%

12. Ridgefield 4kV

During the first quarter of 2022, $42,604 was spent on the Ridgefield 4kV project compared to a forecast of $48,000, which brought the total spend to approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project is essentially complete now with final closeout activities performed during the first quarter of 2022.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$143,414	$11,239,534	$9,263,852	$42,604	$18,000	-	-	-

Actuals to Date	Estimate	% of Actuals to Estimate
$20,689,404	$20,800,000	100%

13. State Street

During the first quarter of 2022, $751,849 was spent on the State Street project compared to a forecast of approximately $636,000, which brought the total spend to approximately $9.6 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the State Street estimate advanced to the Definitive stage with a $500,000 increase to the base estimate (while the R&C was removed as discussed above) for a new estimate of $19.6 million.

The forecasted in-service date for the State Street project as of the end of the first quarter of 2022 slipped 87 days from the status as of the end of 2021 to December 19, 2022. This shift was driven by an updated Southern Division OP schedule for when the first circuit will be ready for energization, which is needed to place the IP substation assets in-service. The initial plan assumed that an overhead route out of the station would be used for this circuit, however during field inspections and detailed engineering it was determined this route was not feasible due to an existing pole in the area that was not known of at the time of initial design. The updated route exits the station at a different side of the station that does not permit overhead electrical infrastructure, thus requiring installation of an underground manhole and duct bank system.

Notable activities performed on State Street during the first quarter of 2022 included the submittal of the test pit permit package and the test pit scope of work sent out for bid. The test pits will inform the engineering design of the 4kV manhole and ductbanks required to be installed through congested underground streets in Camden, New Jersey.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$77,590	$662,148	$8,093,227	$751,849	$1,414,761	$1,146,801	$1,612,741	$6,078,786

Actuals to Date	Estimate	% of Actuals to Estimate
$9,584,815	$19,600,000	49%

14. Toney's Brook

During the first quarter of 2022, $432,853 was spent on the Toney's Brook project compared to a forecast of approximately $403,000, which brought the total spend to approximately $1.7 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Toney's Brooke estimate was revised with no change to the base estimate (while the R&C was removed as discussed above).

The forecasted in-service date for the Toney's Brook project as of the end of the first quarter of 2022 remains unchanged from the status as of the end of 2021 at April 21, 2023.

The primary activities on during the first quarter of 2022 involved the continued advancement of detailed engineering.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$211,940	$373,096	$941,519	$138,270	$116,627	$994,981	$6,016,246	$7,461,650

Actuals to Date	Estimate	% of Actuals to Estimate
$1,664,826	$16,200,000	10%

15. Waverly

During the first quarter of 2022, $432,853 was spent on the Waverly project compared to a forecast of approximately $403,000, which brought the total spend to approximately $7.4 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Waverly estimate was revised with the base estimate increasing from $29.4 million to $36.2 million. This $6.8 million increase in the base estimate was driven by:

- Equipment awards higher than estimated ($2.9 million);
- Additional charges for site plan revisions and related extended project duration ($2.6 million), comprised of:
    - Additional engineering ($0.8 million);
    - Revised fencing and external façade improvements ($1.0 million); and,
    - Additional charges for extended project duration ($0.8 million).
- Change in T&D surcharge methodology ($1.1 million); and,
- Cost of laydown area higher than estimated ($0.2 million).

The current forecast of $37.6 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- Civil construction PO awarded higher than estimated ($1.3 million); and,
- Cost of switchgear storage ($0.1 million).

The forecasted in-service date for the Waverly project as of the end of the first quarter of 2022 continued to advance as the project team details the construction schedule following the site plan approval in December 2021. The current forecasted in-service date advanced 196 days from the status as of the end of 2021 to March 5, 2024.

The primary activities performed during the first quarter of 2022 included the issuance of the Soil Conservation District permit, phase 2 electrical work awarded, and phase 3 civil work awarded.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$103,748	$2,460,815	$4,415,223	$432,853	$7,176,838	$2,542,671	$2,473,315	$18,043,349

Actuals to Date	Estimate	% of Actuals to Estimate
$7,412,639	$36,200,000	21%

16. Woodlynne

During the first quarter of 2022, $1,639,443 was spent on the Woodlynne project compared to a forecast of approximately $1.4 million, which brought the total spend to approximately $3.7 million. As part of the Electric Station Flood Mitigation subprogram re-estimating process that was completed in the first quarter of 2022, the Woodlynne estimate was revised with the base estimate increasing from $15.8 million to $21.3 million. This $5.5 million increase in the base estimate was driven by:

- Higher than estimated civil construction award ($3.9 million);
- Higher than estimated switchgear award ($0.8 million); and,
- Increased carrying cost ($0.8 million).

The current forecast of $24.3 million reflects changes in status, conditions, and assumptions since the time of the estimate update, including specifically:

- Material and civil construction POs higher than estimated and bids ($0.4 million); and,
- Revised Division estimate ($2.6 million).

The forecasted in-service date for the Woodlynne project as of the end of the first quarter of 2022 remains unchanged from the status as of the end of 2021 at October 10, 2023.

Design work continued to progress during the first quarter of 2022 and the civil construction work commenced later in the quarter.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$110,982	$993,298	$991,630	$1,639,443	$660,694	$1,078,409	$6,335,309	$12,500,235

Actuals to Date	Estimate	% of Actuals to Estimate
$3,735,353	$21,300,000	18%

B. Contingency Reconfiguration

During the first quarter of 2022, the final reclosers were installed and commissioned, completing this scope of the Contingency Reconfiguration subprogram. **Table 13 – ES 2 Program Recloser Status as of March 31, 2022** provides a summary of the recloser aspect of the Contingency Reconfiguration subprogram, indicating the number of units completed during the first quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning.

Table 13 – ES 2 Program Recloser Status as of March 31, 2022

Type	Engineering Packages Completed (1 recloser ea.)		Reclosers Installed		Reclosers Commissioned	
	Q1 Qty.	*Program Total*	*Q1 Qty.*	*Program Total*	*Q1 Qty.*	*Program Total*
13kV	6	954	21	954	22	954
4kV	-2	513	2	513	3	513
Total	4	1,467	23	1,467	25	1,467

As shown in **Table 13**, the final 23 reclosers were installed during the first quarter of 2022 along with the commissioning of 25 reclosers (which included two installed at the end of 2021). The reduction of two 4kV recloser engineering packages recorded during the first quarter of 2022 was the result of a reconciliation of the engineering packages, which identified two previously completed engineering packages in the Southern Division that were abandoned after completion of the engineering due to the location no longer being feasible as a result of a change in field conditions stemming from other completed projects that altered the original design condition. PSE&G also removed the costs associated with these two engineering packages from the ES 2 Program.

As previously discussed in prior IM reports, the Fuse Saver pilot program commenced in November 2020 and was primarily completed in January 2021. In total, this phase of the Fuse Saver pilot program included the installation and commissioning of 80 Fuse Saver devices with an additional 33 units installed during the second half of 2021 to allow PSE&G to capture additional cost and performance data from the existing inventory of Fuse Savers. During execution of the pilot program, PSE&G observed factors that will help it prepare for execution of the full Fuse Saver scope, including installation specifications (the remote control unit (RCU) must be placed directly below the Fuse Saver to avoid communications issues), and cost elements for some of the locations (new poles, traffic control, etc.). The observed experience from the 113 units installed in the pilot program saw communications issues present at 10 locations, with the external antenna addressing the communication issues at added cost of approximately $1,100 per unit (plus some additional labor to install the antenna). While monitoring performance of the installed Fuse Savers, PSE&G experienced other communication issues between the Fuse Savers and the RCU, wherein the Supervisory Control and Data Acquisition (SCADA) communication indicated a false open/close alarm on some of the devices. Siemens has provided a prototype Fuse Saver to address the communication issues, which PSE&G will monitor to ensure it addresses the issues prior to placing additional orders. Because of this, commencement of the full Fuse Saver scope was pushed to 2022 and is expected to commence during the second quarter of 2022.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2022**. This table also shows the forecasted final in-service dates as of the end of 2021 to show movement to the forecast as of the end of the first quarter of 2022.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of March 31, 2022

Scope & Division		Q4 2021 Forecasted Completion Date	Q1 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022	1/31/2022 (Actual)
	Metro	12/31/2021	12/31/2021 (Actual)
	Palisades	2/28/2022	1/31/2022 (Actual)
	Southern	1/31/2022	1/31/2022 (Actual)
Fuse Savers	Central	9/30/2023	9/30/2023
	Metro	10/31/2023	10/31/2023
	Palisades	12/30/2023	11/30/2023
	Southern	9/30/2023	9/30/2023

As shown in **Table 14**, the Central, Palisades, and Southern Divisions completed their respective recloser scopes at the end of January 2022 (while the Metro Division had previously completed its recloser scope in December 2021). The forecasted in-service dates for the Fuse Saver scope remained unchanged from the prior quarter for three of the four Divisions, with the Palisades Division advancing its forecasted final

in-service date to the end of November 2023, and each Division forecasted to complete this scope between September-November 2023.

The Contingency Reconfiguration subprogram costs through the end of the first quarter of 2022 are presented in **Table 15 – ES 2 Contingency Reconfiguration Costs as of March 31, 2022**.

Table 15 – Contingency Reconfiguration Costs as of March 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Total to Date	Forecast	% of Actuals to Forecast
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$25,521,336	$25,521,336	100%
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	$24,476,775	$24,476,776	100%
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$22,848,756	$22,848,756	100%
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$29,054,997	$29,054,997	100%
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$1,903,293	$10,376,485	18%
	Metro	$7,557	$561,915	$507,742	$160,801	$1,238,016	$11,787,531	11%
	Palisades	$7,468	$522,454	$577,113	$127,207	$1,234,242	$9,566,946	13%
	Southern	$9,792	$859,014	$578,217	$245,990	$1,693,013	$11,640,444	15%
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$107,970,428**	**$145,273,272**	**74%**

As shown in **Table 15**, while the Contingency Reconfiguration subprogram forecast remained relatively unchanged from the prior quarter (in total, decreased approximately $500,000), the Central and Palisades Division forecasts for the Fuse Savers scope experienced more variance with the Central Division Fuse Savers scope decreasing by approximately $1.7 million and the Palisades Division Fuse Savers scope increasing by approximately $1.1 million. These forecast changes were driven by an adjustment to the number of Fuse Saver units assigned to each Division with the reallocation assigning a more equal number of units to each Division. In addition, the negative actuals recorded in the first quarter of 2022 in the Palisades Division for the reclosers scope was the net result of credits received for eight reclosers removed from the subprogram.

Findings & Observations:

- The final 23 reclosers on the subprogram were installed during the first quarter of 2022. With these final installations, the total number of reclosers installed in the ES 2 Program was 1,467 (954 13kV devices and 513 4kV devices).
- The status of the Fuse Savers scope of the subprogram remained relatively unchanged, with no installations in the period and no change in the forecasted final in-service dates for three of the four the Divisions, while the Palisades Division advanced its forecasted final in-service date approximately 30 days. The Fuse Savers costs incurred in the first quarter of 2022 related to advancing and completing more engineering packages in advance of the upcoming installations.
- The Contingency Reconfiguration subprogram forecast continued to remain relatively static as of the end of the first quarter of 2022 from the end of 2021, with the total forecast decreasing by approximately $494,000 (or 0.3%) to $145.3 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of

dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the first quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers.
- Fiber installations and cutovers: 27 out of 38 fiber installation projects completed and 11 out of 12 fiber cutover projects completed.
- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.
- Retrofitting RTUs: 85 substation retrofits completed (75 during the first quarter of 2022) out of a current scope of 218 substations.

The retrofit RTU scope increased from 196 substations to 218 substations following PSE&G's determination to include not only substations served by Verizon plain old telephone service (POTS) (which represented the 196 substations), but also those served by Verizon 4G service (which represented the 22 additional stations). This brings the scope in alignment with PSE&G's objective of replacing all third party RTU communication services within its system.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects since removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. The list of identified fiber installation and cutover projects is presented in **Table 16 – ES 2 Program Fiber Projects by Division as of March 31, 2022**.

Table 16 – ES 2 Program Fiber Projects by Division as of March 31, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue**	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly**	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights**; Thirty Second Street**	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***

**Projects underlined have been placed in-service.*
***-Identified for removal from subprogram during Q2 2022 (see **Section IV**).*

During the first quarter of 2022, seven additional fiber installation projects (Central HQ, Culver Ave, Fort Lee, Hadley Road HQ, Haledon, Ridgewood, and West New York) and two additional fiber cutover projects (Fairview and Polk Street) were placed in-service. This brought the total projects in-service as of the end of the first quarter of 2022 to 27 for the fiber installation projects and 11 for the fiber cutover projects. **Table 17 – ES 2 Program Fiber Projects Status as of March 31, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the first quarter of 2022 with the projects in italics representing those placed in-service.

Table 17 – ES 2 Program Fiber Projects Status as of March 31, 2022

Project Name	Q1 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued construction
Bordentown	*In-Service (Q3 2021)*
Carteret	IP work preparation underway; awaiting railroad permits
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	IP work preparation underway; awaiting railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Preliminary engineering*
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	IP work preparation underway; awaiting railroad permits
Lehigh Avenue	Preliminary engineering*
Mechanic Street	IP work preparation underway; awaiting railroad permits
Metro HQ	*In-Service (Q1 2021)*
Montclair	Continued construction
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	IP work preparation underway; awaiting railroad permits
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Preliminary engineering*
Waverly	Preliminary engineering*
West New York	*In-Service (Q1 2022)*

Project Name	Q1 2022 Status
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	Completion dependent upon redundant link to Montclair substation being ready (two redundant fiber links required for each router to support reliability guidelines)
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	85 cutovers completed
-Project identified for removal from subprogram after the current reporting period, see **Section IV for additional information.*	

The Grid Modernization – Communication System subprogram costs through the end of the first quarter of 2022 are presented in **Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2022**.

Table 18 – ES 2 Grid Modernization – Communication System Costs as of March 31, 2022

Scope & Division		2019	2020	2021	Q1 2022	Total to Date	Total Forecast	% of Actuals to Forecast
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$4,404,349	$6,700,030	66%
	Metro	$0	$818,620	$2,362,779	$135,374	$3,316,774	$5,593,403	59%
	Palisades	$0	$825,174	$3,115,474	$186,059	$4,126,707	$6,387,150	65%
	Southern	$0	$929,058	$3,862,816	$194,826	$4,986,700	$7,259,273	69%
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$9,975,460	$10,727,513	93%
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$6,530,578	$7,717,563	85%
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$6,307,785	$6,398,139	99%
	Southern	$4,731	$910,483	$2,466,477	$96,721	$3,478,412	$4,236,200	82%
	Cutovers*	$0	$876,502	$607,056	$851,293	$2,334,850	$3,249,145	72%
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$7,454,290	$7,875,891	95%
Bulk Purchase**		$0	$1,524,874	($520,766)	$641,029	$1,645,137	$0	-
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$54,561,043**	**$66,144,306**	**82%**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

As shown in **Table 18**, the total forecast for the Grid Modernization – Communication System subprogram increased to $66.1 million as of the end of the first quarter of 2022, up approximately $2.5

million from the $63.6 million forecast as of the end of 2021. This increase was primarily driven by the following factors:[2]

- Fiber – Central Division: forecast increased $1.2 million, comprised of:
  - Added Lehigh Avenue project to the subprogram scope/forecast: $0.5 million.
  - Added scope required for battery installation at Edison: $0.2 million.
  - Additional OP Division labor required: $0.3 million.
  - Updated vendor quotes on IP finishing work (Keasbey, Mechanic Street, and Edison): $0.2 million.
- Fiber – Palisades Division: forecast increased $0.2 million, comprised of West New York to Polk Street trailing underground chargers higher than initially forecasted.
- Fiber – Southern Division: forecast increased $0.9 million, comprised of:
  - Added Haddon Heights project to the subprogram scope/forecast: $0.7 million.
  - Higher project management costs than previously forecasted: $0.2 million.
- Substation RTU Cutovers: forecast increased $0.2 million, comprised of an increase in actual costs per unit driven by the complexity of antenna installation at certain stations with a need for Division labor not previously identified.

Findings & Observations:

- The retrofit substation RTU scope ramped up in the first quarter of 2022, with 75 substations completed during the quarter (and 85 total completed) out of a currently forecasted scope of 218 substations.
- Seven additional fiber installation projects and two additional fiber cutover projects were placed in-service during the first quarter of 2022, bringing the total number of projects in-service to 27 fiber installation projects and 11 fiber cutover projects. The fiber scope is expected to be completed by the end of 2022 (see also **Section IV** concerning changes to the fiber scope that occurred after the first quarter of 2022).
- The forecast for the Grid Modernization – Communication system subprogram increased by approximately $2.5 million from the status as of the end of 2021 to $66.1 million as of the end of the first quarter of 2022. The forecast increase was driven by higher costs in the current fiber projects (cost drivers on the individual projects included additional scope, additional labor requirements, and updated vendor quotes).

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the first quarter of 2022 are presented as follows:

[2] Note: part of the forecast increase included adding the Lehigh Avenue and Haddon Heights projects to the subprogram forecast, these projects were subsequently removed from the subprogram during the second quarter of 2022 due to budgetary constraints, see **Section IV**.

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q1 2022 Activities:
    - Prepared and sent laptop to Open Systems International, Inc. (OSII) for use with testing.
    - Completed Sprint 14 & 15.
    - Completed schedule review.
    - Reorganized review of variance documentation with OSII.
- Forecasted Completion as of the end of the first quarter of 2022: 12/19/2022.

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q1 2022 Activities:
    - Completed virtual private network (VPN) weather interface.
    - Completed onsite meetings to review SAP claims requirements and configurations.
    - Completed Sprint 12 and Sprint 12 retrospective.
    - Completed onsite visit for schedule planning for damage records, referrals, and reporting.
    - Completed reviews with cyber security.
    - Completed first and second round of converted data and feedback sessions.
    - Completed Sprint 13.
- Forecasted Completion as of the end of the first quarter of 2022: 4/30/2023.

ADMS Platform

- Scope: Replace, enhance, and expand the existing DSCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q1 2022 Activities:
    - Completed System Acceptance Testing (SAT) and analysis of results.
    - Completed vulnerability testing.

- Completed deconstruction of Edison Production rack.
- Imaged workstations for Divisions in preparation for training.

- Actual In-Service Date: 1/28/2022.

The currently forecasted in-service dates for the OMS scopes slipped 128 days from the status as of the end of 2021. This shift in the forecasted completion of the OMS scope was the result of rescheduling the "go live" date due to delays in the OMS interface alignment with Mobile Work Management System (MWMS), which was driven by delays in the in-service date of the MWMS (which is not part of the ES 2 Program). The ADMS Platform was placed in-service on January 28, 2022.

The Grid Modernization – ADMS subprogram costs through the end of the first quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2022**.

Table 19 – ES 2 Grid Modernization – ADMS Costs as of March 31, 2022

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$36,213	$16,447,624	$9,854,442	$3,197,877	$2,764,836	$2,474,510	$6,673,902	$2,076,489

Actuals to Date	Forecast	% of Actuals to Forecast
$29,536,155	$43,525,894	68%

Findings & Observations:

- The first of three primary ADMS components was placed in-service during the first quarter of 2022 (the ADMS Platform). While the remaining DMS/DERMS and OMS are currently forecasted to be placed in-service in December 2022 and April 2023, respectively. The OMS scope was rescheduled during the first quarter of 2022 to account for delays to the MWMS (outside of ES 2, but interface alignment required to complete the OMS scope).
- The Grid Modernization – ADMS forecast as of the end of the first quarter of 2022 increased very slightly (approximately $32,000) from the end of 2022, with the total forecast remaining at $43.5 million.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric Outside Plant-Higher Design Standards (OP-HDS) and/or electric stations life cycle subprograms described in the original ES 2 filing.[3] The OP-HDS scope is expected to commence in the summer of 2022 with detailed engineering on a number of circuits that meet the upgrade criteria and reflective of the circuit prioritization, the OP-HDS work is expected to continue through December 2023. In accordance with what the Stipulation provides, PSE&G plans to

[3] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. These five stations and their current estimate compared to the actuals to date are provided in **Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022**.

Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Study	$16,200,000	-	$16,200,000	$7,274,152	45%	10/28/2022 (↓ +16)
2. Paramus	Study	$20,500,000	-	$20,500,000	$8,861,478	43%	11/14/2022 (↑ -45)
3. Plainfield	Study	$22,700,000	-	$22,700,000	$5,948,906	26%	11/8/2022
4. Woodbury	Study	$17,800,000	-	$17,800,000	$3,625,514	20%	12/30/2022 (↓ +3)
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$607,150	3%	12/19/2022 (↑ -132)
R&C Balance	-	-	$3,100,000	$3,100,000	-	-	-

-As discussed in **Section II.B., during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 20**, of the five life cycle station upgrade projects, the Paramus and State Street OP projects saw respective forecasted in-service dates advance during the first quarter of 2022, while the Hamilton and Woodbury projects saw their respective forecasted in-service dates slip during the first quarter of 2022. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Findings & Observations:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which is expected to commence construction in the fourth quarter of 2022).
- There was movement in the forecasted in-service dates for four of the five life cycle upgrade projects during the first quarter of 2022. For Hamilton and Woodbury, the changes were relatively minor (slipping 16 days and 3 days, respectively). While the Paramus project advanced

45 days driven by better than planned construction progress and the State Street OP project advanced 132 days based on an updated schedule from Southern Division on the completion of the circuit, which is required to complete the project.

- The cost forecasts for the five life cycle upgrade projects collectively increased $1.3 million (or 1.3%) from the status as of the end of 2021 to a total forecast of $98.6 million as of the end of the first quarter of 2022. This increase was distributed fairly evenly across the individual projects.

1. Hamilton

During the first quarter of 2022, $3,770,758 was spent on the Hamilton project against a forecast of approximately $3.7 million. This brought total spend on the project to approximately $7.3 million through the end of the first quarter of 2022. The forecasted in-service date for the Hamilton project slipped 16 days from the status as of the end of 2021 to October 28, 2022.

Notable activities conducted during the first quarter of 2022 included the completion of the switchgear foundations and partial delivery of the switchgear (with regulators expected to be delivered in April 2022).

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$362,372	$3,141,022	$3,770,758	$3,315,653	$2,406,733	$2,269,989	$1,583,299

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$7,274,152	$16,200,000	$16,849,828	45%

2. Paramus

During the first quarter of 2022, $952,513 was spent on the Paramus project against a forecast of approximately $922,000. This brought total spend on the project to approximately $8.9 million through the end of the first quarter of 2022. The forecasted in-service date for the Paramus project advanced from December 29, 2022, as of the end of 2021, to November 14, 2022, as of the end of the first quarter of 2022. This advancement in the forecasted in-service date was driven by construction progressing better than anticipated.

Notable activities conducted during the first quarter of 2022 on the Paramus project included:

- Pre-construction license and permit compliance/construction requirement review with contractor completed;
- All circuit cutovers completed on the contingency switchgear; and,
- Existing feeder row demolition commenced.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$0	$840,200	$7,068,765	$952,513	$6,053,040	$1,458,915	$1,094,131	$3,510,574

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,861,478	$20,500,000	$20,978,138	43%

3. Plainfield

During the first quarter of 2022, $1,682,480 was spent on the Plainfield project against a forecast of approximately $1.7 million. This brought total spend on the project to approximately $5.9 million through the end of the first quarter of 2022. The forecasted in-service date for the Plainfield project as of the end of the first quarter of 2022 remained unchanged from the prior quarter at November 8, 2022.

Notable activities conducted during the first quarter of 2022 included the award of the electrical construction scope of work, which is expected to commence in June/July 2022.

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$682,325	$3,584,101	$1,682,480	$6,147,328	$5,429,853	$1,710,404	$3,479,832

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,948,906	$22,700,000	$22,716,323	26%

4. Woodbury

During the first quarter of 2022, $1,460,525 was spent on the Woodbury project against a forecast of approximately $1.1 million. The variance between forecasted and actual spend in the first quarter was driven by additional soil loadouts and more water sampling needed as well as contracted material handling and control work completed ahead of schedule. This brought the total spend on the project to approximately $3.6 million through the end of the first quarter 2022. The forecasted in-service date for the Woodbury project slipped from December 27, 2022 as of the end of 2021 to December 30, 2022 as of the end of the first quarter of 2022.

Notable activities conducted during the first quarter of 2022 included the start of preliminary civil manhole/conduit work.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$0	$551,165	$1,613,823	$1,460,525	$5,006,277	$3,307,944	$2,436,417	$3,958,921

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,625,514	$17,800,000	$18,335,072	20%

5. State Street (Outside Plant)

During the first quarter of 2022, $395,903 was spent on the State Street (OP) project against a forecast of approximately $291,921. The variance between forecasted and actual spend in the first quarter was driven by the A/E completing more design and engineering work and more test pits completed than planned This brought the total spend on the project to approximately $607,000. The forecasted in-service date for the State Street OP project advanced from April 30, 2023, as of the end of 2021, to December 19, 2022, as of the end of the first quarter of 2022. This shift was driven by the Southern Division committing to completing the State Street OP 4kV circuit by the end of 2022.

Notable activities conducted during the first quarter of 2022 included the continuation of detailed engineering.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$0	$0	$211,247	$395,903	$884,618	$2,397,665	$1,969,139	$13,854,017

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$607,150	$19,700,000	$19,712,589	3%

F. Gas M&R Station Upgrades

During the first quarter of 2022, three additional projects commenced construction activities (Camden, Central, and East Rutherford), while the Westampton project continued closeout and restoration activities following it being placed in-service in October 2021. **Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022** below provides the currently approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Study	$24,300,000	$5,000,000	$29,300,000	$5,812,073	20%	Dec 2022 (↑)
2. Central*	Study	$23,900,000	$5,100,000	$29,000,000	$12,016,345	41%	Nov 2023 (↓)
3. East Rutherford	Study	$13,800,000	$2,700,000	$16,500,000	$3,865,788	23%	Dec 2022 (↑)
4. Mount Laurel	Study	$9,400,000	$2,000,000	$11,400,000	$1,031,112	9%	Nov 2023 (↓)
5. Paramus*	Study	$11,500,000	$2,200,000	$13,700,000	$1,134,392	8%	Dec 2023
6. Westampton	Study	$9,100,000	$900,000	$10,000,000	$8,180,404	82%	Oct 2021
Subprogram Total		**$92,000,000**	**$17,900,000**	**$109,900,000**	**$32,040,114**	**29%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

The in-service dates for the Central and Mount Laurel projects as of the end of the first quarter of 2022 slipped approximately 11 months to November 30, 2023, which was driven by a change in schedule priorities for 2022 work. This shift improves the balancing of the spend across the Program duration and avoids outage constraints that require the projects' in-service dates to occur prior the winter heating season. PSE&G anticipates no significant cost increases as a result of this shift in schedule prioritization. As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The primary efforts to date on the subprogram continue to be primarily related to pre-construction planning efforts, including completing and submitting site plan packages, ordering long lead materials, and awarding the construction work. The Camden, Central, and East Rutherford projects each started the construction phase during the first quarter of 2022.
- The in-service dates of two projects (Central and Mount Laurel) shifted out approximately 11 months to November 2023, which reflected a change in the execution strategy of these projects to better balance the subprogram spend across the full Program and to avoid outage constraints. No meaningful cost impacts are anticipated as a result of this shift.
- The subprogram forecast increased from $107.8 million as of the end of 2021 to $128.3 million as of the end of the first quarter of 2022. The largest contributor for this increase was a $10.2 million increase to the Camden project forecast (while the Central, East Rutherford, and Mount Laurel projects each saw forecast increases of approximately $3.3 to $3.6 million). The forecast increase was driven by additional costs for materials, equipment, and construction based on purchase orders and bid proposals compared to the initial project estimates.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, particularly given the advancement of the final projects in the subprogram (Central, Mount Laurel, and Paramus). The continued cost pressures noted above have pushed the subprogram forecast to approximately $27.3 million above the Stipulation budget of $101 million.

1. Camden

During the first quarter of 2022, $2,791,701 was spent on the Camden project compared to a forecast of approximately $2.9 million, which brought the total spend to approximately $5.8 million. The forecasted in-service date for the Camden project as of the end of the first quarter of 2022 advanced 14 days from the status as of the end of 2021 to December 16, 2022.

Notable activities completed on the Camden project during the first quarter of 2022 included:

- Received foundation and structural permits;
- Awarded construction contract and held construction kickoff meeting;
- IFC mechanical drawings released; and,
- Site construction commenced.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$13,326	$859,350	$2,147,696	$2,791,701	$10,015,027	$12,778,011	$6,840,283	$1,154,606

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,812,073	$29,300,000	$36,600,000	16%

2. Central

During the first quarter of 2022, $7,112,617 was spent on the Central project compared to a forecast of approximately $7.5 million, which brought the total spend to approximately $12.0 million. The variance in first quarter spend was largely driven by later than expected receipt of final building drawings, which impacted the construction permits and the start of construction. The forecasted in-service date for the Central project as of the end of the first quarter of 2022 slipped 335 days from the status as of the end of 2021 to November 30, 2023 due to a reprioritization of the sequencing of the projects.

Notable activities completed on the Central project during the first quarter of 2022 included:

- Removed portions of existing underground pipelines due to interferences;
- Received majority of steel pipe and some fittings to the site;
- Set up laydown areas;
- Received IFC drawings from the building manufacturer;
- Installed safety fence along access road; and,
- Started demolition and civil work.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$6,869	$670,582	$4,226,277	$7,112,617	$6,629,415	$3,939,027	$2,447,316	$12,367,898

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$12,016,345	$29,000,000	$37,400,000	32%

3. East Rutherford

During the first quarter of 2022, $1,551,290 was spent on the East Rutherford project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $3.9 million. The variance in first quarter spend was driven by the contractor mobilizing to site and receiving materials earlier than anticipated, which also locked in material pricing to avoid price increases. The forecasted in-service date for the East Rutherford project as of the end of the first quarter of 2022 advanced 14 days from the status as of the end of 2021 to December 16, 2022.

Notable activities completed on the East Rutherford project during the first quarter of 2022 included:

- IFC drawings received from A/E;
- Order placed for small diameter pipe and fittings;
- Began receiving materials on site;
- Installed site fence around perimeter and construction trailer delivered;
- Began performing test pits on site; and,
- Began submitting material test records for approval.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$9,010	$521,865	$1,783,623	$1,551,290	$5,547,595	$7,740,480	$3,843,635	$702,502

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$3,865,788	$16,500,000	$21,700,000	18%

4. Mount Laurel

During the first quarter of 2022, $135,639 was spent on the Mount Laurel project compared to a forecast of approximately $96,000, which brought the total spend to approximately $1.0 million. The forecasted in-service date for the Mount Laurel project as of the end of the first quarter of 2022 slipped 335 days from the status as of the end of 2021 to November 30, 2023 due to a reprioritization of the sequencing of the projects.

Notable activities completed on the Mount Laurel project during the first quarter of 2022 included the conditional approval of the site plan by the township planning board.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals				*Forecast*			
$5,965	$362,167	$527,341	$135,639	$58,457	$77,421	$102,058	$11,430,952

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,031,112	$11,400,000	$12,700,000	8%

5. Paramus

During the first quarter of 2022, $94,755 was spent on the Paramus project compared to a forecast of approximately $140,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Paramus project as of the end of the first quarter of 2022 remains unchanged from the forecast as of the end of 2021 at December 29, 2023.

Notable activities completed on the Paramus project during the fourth quarter of 2021 included:

- Soil erosion permit approved; and,
- Paramus zoning board approved the project.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$8,842	$462,452	$568,344	$94,755	$150,612	$118,427	$694,206	$9,402,362

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,134,392	$13,700,000	$11,500,000	10%

6. Westampton

During the first quarter of 2022, $178,124 was spent on the Westampton project compared to a forecast of approximately $130,000, which brought the total spend to approximately $8.2 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that will carry over into 2022.

During the first quarter of 2022, notable activities on the Westampton project included:

- New perimeter fence installed; and,
- Security cameras/security system installed.

The remaining items to closeout the project include corrosion protection work and final punch list items relating to site paving/grading. PSE&G expects these activities to be fully complete around July.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals				*Forecast*			
$8,395	$1,032,670	$6,961,216	$178,124	$187,876	$33,985	$34,045	$0

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,180,404	$10,000,000	$8,436,311	97%

IV. Additional Information Following the end of the First Quarter of 2022

While the vast majority of this IM report is focused on the activities and status of the ES 2 Program during the first quarter of 2022, the timing of certain Program elements and information provided by PSE&G naturally carried over beyond the end of the calendar quarter. Such information will generally be covered in the next IM quarterly report but given the importance of some of this information as it pertains to the ES 2 Program, the IM has provided additional remarks to provide a more complete view of these mitigation changes based on the available information as of the date of this IM 2022 First Quarter Report.

Grid Modernization – Communication System

During the second quarter of 2022, PSE&G updated its fiber project listing based on the current status of scope and cost refinement across the projects and a prioritization of projects based on the available budget. As a result, four additional fiber projects were removed from the subprogram (Haddon Heights, Lehigh Avenue, Thirty-Second Street, and Waverly). Of these projects selected for removal, Waverly was

the only one that was identified in the ES 2 filing and its removal was based on the determination that Waverly project under the Electric Station Flood Mitigation subprogram included fiber installation for the IP scope (with base capital funding provided for the OP scope). For the other three projects selected for removal, each was part of the additional locations reviewed by PSE&G for inclusion in the subprogram as part of the full review of all PSE&G substations and Operation Centers previously conducted (see Section IV.A. in the IM 2020 Third Quarter Report). Ultimately, the available budget did not allow these additional projects to be included within the ES 2 Program, though PSE&G has indicated to the IM that the Haddon Heights and Lehigh Avenue fiber projects will be executed outside of the ES 2 Program.

The Stipulation approved $72 million to be invested in the Grid Modernization – Communication System subprogram, but otherwise did not specify specific fiber projects. Following the earlier detailed review conducted by PSE&G to verify current status and communication needs and the current adjustment based on the available budget, the fiber scope now contains fiber installations at 27 distribution substations and eight Operation Centers, in addition to fiber cutovers to stations with existing fiber and the retrofitting of substation RTUs.

This complete list of fiber projects, including those originally proposed, those added (including those preliminarily added and later removed), and those removed, along with their corresponding cost data has been assembled in **Table 22 – ES 2 Fiber Project Status as of March 2023**.

Table 22 – ES 2 Fiber Project Status as of March 2023

Project Name	ES 2 Program Status	Budget*	Forecast	Actual
Bergen Point	Original	$750,000	$701,459	$702,777
Bloomfield	Original	$300,000	$1,482,687	$869,907
Bordentown	Added	$0	$682,285	$687,515
Carteret	Added	$0	$753,816	$974,932
Central Ave	Original	$480,000	$112,759	$113,360
Central HQ	Original	$570,000	$1,800,274	$1,881,116
Chauncey Street	Original	$840,000	$875,395	$870,023
Cranford	Original	$300,000	$357,876	$363,658
Culver Ave	Added	$0	$832,145	$861,758
East Orange	Original	$480,000	$1,143,568	$1,026,100
Edison	Added	$0	$1,070,066	$1,484,149
Elizabeth	Removed**	$210,000	$0	$0
Elizabeth Sub HQ	Original	$555,000	$749,712	$750,226
First Street	Original	$300,000	$618,118	$618,401
Fort Lee	Original	$480,000	$1,263,941	$1,262,214
Hackensack	Removed	$480,000	$0	$0
Hackensack Sub HQ	Original	$825,000	$595,412	$619,055
Haddon Heights	Added & Removed***	$0	$738,942	$0
Hadley Rd HQ	Added	$0	$1,460,786	$1,583,448
Haledon	Original	$300,000	$567,567	$610,260
Harrison	Original	$300,000	$576,805	$576,805
Howell Street	Added & Removed	$0	$0	$0
Irvington	Original	$300,000	$174,633	$175,166
Irvington Sub HQ	Original	$300,000	$601,657	$634,347
Keasbey	Original	$840,000	$784,856	$1,051,327
Lakeside	Removed	$570,000	$0	$0
Lehigh Avenue	Added & Removed***	$0	$818,014	$0

Project Name	ES 2 Program Status	Budget*	Forecast	Actual
Market Street	Removed	$390,000	$0	$0
Mechanic Street	Original	$1,200,000	$925,256	$1,047,867
Metro HQ	Original	$300,000	$582,568	$583,020
Montclair	Original	$840,000	$2,147,782	$2,696,966
Morgan Street	Added	$0	$518,181	$534,856
Nineteenth Ave.	Removed	$390,000	$0	$0
Norfolk St	Original	$300,000	$186,265	$187,317
Orange Valley	Removed	$300,000	$0	$0
Palisades HQ	Original	$255,000	$409,690	$616,105
Princeton	Original	$300,000	$1,132,137	$1,129,128
Rahway	Original	$390,000	$1,026,601	$1,075,955
Ridgewood	Original	$390,000	$483,367	$491,302
Roselle	Original	$390,000	$428,183	$430,033
So Orange	Original	$390,000	$312,099	$314,997
Southern HQ	Original	$570,000	$708,350	$672,201
State Street	Removed	$390,000	$0	$0
Thirty Second Street	Added & Removed	$0	$0	$0
Toney's Brook	Removed	$480,000	$0	$0
Waverly	Removed***	$300,000	$439,640	$0
West New York	Original	$300,000	$997,565	$930,181

*-Only the projects from the initial list had established budgets.
**-The Elizabeth Substation retained a fiber cutover scope that was executed as part of the ES 2 Program.
***-These projects were/will be completed outside of the ES 2 Program.

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 FIRST QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

APRIL 17, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 First Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q1 2022 Report, Page 16** Please provide additional details explaining how PSE&G's plan to use the contingency switchgear from the Ridgefield 13kV project on the Kingsland project will result in cost efficiencies. Please also indicate when PSE&G expects to obtain the contingency switchgear to be used on the Ridgefield 13kV project.	The use of the Kingsland and Meadow Road switchgears as temporary (contingency) switchgears on the Ridgefield 13kV and Leonia projects, respectively, resulted in cost savings approximately equal to the purchase price of two 13kV sheltered aisle switchgears. Each project would have had to spend an additional $1.69 million (the actual price for the switchgears at Kingsland and Meadow Road) if PSE&G had not utilized the switchgears at Ridgefield 13kV and Leonia in this approach as these projects both required contingency switchgear to facilitate a construction sequence that maintained reliable supply to the customers.	**Section III.A.**
S-INF-2	**Reference Q1 2022 Report, Page 20, Front Street Substation** Regarding the Front Street Substation project: a. Please provide additional details about the "higher than estimated switchgear award ($2.1 million)", including the budgeted and actual cost of the switchgear. Please also describe the competitive bidding process utilized. b. Please explain why PSE&G elected to utilize an external A/E firm rather than in-house engineering as initially planned (resulting in an increase of $0.3 million).	The contract award price for the permanent switchgear was $5,540,793, with PSE&G adding a 10% management reserve to its cost account not part of the purchase order to cover unforeseen changes in scope (project complexities or field conditions). This was $1.2 million above PSE&G's estimate (with the contingency switchgear accounting for an additional $0.9 million above PSE&G's estimate). This appears to generally reflect market conditions as similar switchgear ordered earlier in the Program (pre-Covid 19) from the same vendor was approximately $1.4 million less than this current order. As with other switchgear procurements, PSE&G utilized a competitive bid process for the award of the Front Street switchgear. This included requests for quotations issued to three vendors, with two submitting bids (PowerCon and Powell). The evaluation criteria included: delivery date, cost, PSE&G specification, testing and commissioning, technical exceptions, installations support, warranty and other terms and conditions, training, previous project performance, and supplier diversity spend. Based on PSE&G's evaluation of the bids, it found Powell had a slightly more competitive commercial proposal (approximately $5.1 million against approximately $5.5 million), but PowerCon had a superior technical proposal. Additionally, while both vendors have past experience with PSE&G, Powell provided the Waverly 4kV switchgear, which saw approximately $300K in change	**Section III.A.3.**

ID #	Question/Comment	IM Response	Report Changes
		orders and were anticipated to be expected on this switchgear as well if Powell was awarded the work. Thus, based on the superior technical proposal and the past experience, PSE&G awarded this switchgear to PowerCon. Concerning the switch from internal resources to an external A/E, PSE&G determined it did not have the resources available to support the project schedule. PSE&G did perform the preliminary engineering on this project before outsourcing the detailed engineering.	
S-INF-3	**Reference Q1 2022 Report, Page 25, State Street Substation** Regarding the State Street Substation project, please provide additional details explaining why the first circuit will not be ready for energization when originally expected (resulting in a delay of 87 days).	When the project started field inspections and detailed engineering, it was determined that the initially planned overhead route was not feasible due to an existing overhead pole in the area that was not known at the time of the initial design. The updated route changes to exit the station at a different side of the station, which required installation of an underground manhole and duct bank system as overhead electrical infrastructure is not permitted on this side of the station.	**Section III.A.13.**
S-INF-4	**Reference Q1 2022 Report, Page 26, Waverly Substation** Regarding the Waverly Substation project: a. Please provide additional details about the "Additional charges for site plan revisions and related extended project duration ($2.6 million)". b. Please estimate the total costs associated with site plan revisions to date.	PSE&G's $2.6 million estimate of the costs resulting from the revised site plan is comprised of: additional engineering ($0.8 million), revised fencing and external façade improvements ($1.0 million), and additional charges for extended project duration ($0.8 million). Concerning the actual site plan revisions, based on the feedback received from the City of Newark Zoning Board and others involved in the community outreach, PSE&G redesigned the street facing frontages of the project to have a fence with a brick finish such that they appear to be walls, with the two entrances gates having a matching color scheme. The fences have locations for artwork to be placed with lighting for nighttime viewing. Additionally, the portions of the isolation walls that are visible were redesigned to match the brick and related features and finishes of the street facing fences. The new site plan also included the addition of street trees, shrubs and landscaping in the sidewalk area that will not interfere with the electric utilities.	**Section III.A.15.**
S-INF-5	**Reference Q1 2022 Report, Page 29, Contingency Reconfiguration Subprogram** Regarding the Fuse Savers scope, please indicate if there were any adjustments during Q1 2022 to the total number of Fuse Saver units to be installed.	During the first quarter of 2022, there was no change to the targeted number of Fuse Savers to be installed in the Program, which remained at 1,713 units. PSE&G's approach has been to review the actual cost data and related installation status information on a quarterly basis to update the installation plan and overall quantity of units planned for the Program.	No change

ID #	Question/Comment	IM Response	Report Changes
S-INF-6	**Reference Q1 2022 Report, Page 30, Grid Modernization – Communication System Subprogram** Regarding the Retrofit Substation Remote Terminal Unit (RTU) scope: a. What is attributed to the scope increasing from 196 substations (as indicating in the IM's Q4 2021 Report, Page 32) to 218 substations? b. Please compare the cost of the current scope to the cost of the originally budgeted scope.	The retrofit substation RTU scope increased from 196 to 218 to support PSE&G's objective of replacing all third party RTU communication service within its system rather than an earlier assumption to replace only those relying on plain old telephone service (POTS). The 196-unit scope was based on the substations served on Verizon POTS lines, while the 218-unit scope adds 22 other substations that are served by Verizon 4G service. The original budget for the substation RTU scope was $1,629,394 to replace 218 units. The actual costs per unit have increased by approximately 15% over the original budget driven by additional work to install antennas on the external of the control houses at some substations.	**Section III.C.**
S-INF-7	**Reference Q1 2022 Report, Page 32, Grid Modernization – Communication System Subprogram** Please provide the anticipated in-service date of the fiber cutover project "West Orange."	The West Orange project was successfully cutover to the TFI network on August 11, 2022.	No change
S-INF-8	Regarding the Grid Modernization – Communication System (Fiber Scope), please identify all locations added to the project scope (pursuant to the Record of Decision decisions in Section IV.A. of the IM 2020 Third Quarter Report) and provide their estimated costs. Please also identify all locations removed from the project scope and provide their originally budgeted costs.	This complete list of fiber projects, including those originally proposed, those added, and those removed, along with their corresponding cost data has been assembled and inserted into the body of the report at **Section IV.**	**Section IV.**
S-INF-9	**Reference Q1 2022 Report, Page 36, Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022** Please clarify if the risk and contingency associated with Electric Stipulated Base projects is included within the total risk and contingency for the Electric Station Flood Mitigation subprogram ($41.8 million). If not, please provide the risk and contingency associated with the Electric Stipulated Base project.	The R&C for the electric Stipulated Base life cycle projects is held under a subprogram placeholder as base funding. As of March 31, 2022, this base funding had a $3.1 million balance.	**Table 20**
S-INF-10	**Reference Q1 2022 Report, Page 38, Plainfield Substation**	The $20,978,138 forecast shown for Plainfield had incorrectly copied the Paramus forecast. The correct forecast for the Plainfield project as of the end of the first quarter of 2022 is $22,716,323. This represents an increase of approximately	**Section III.E.3.**

ID #	Question/Comment	IM Response	Report Changes
	What is attributed to the decrease in the forecasted cost of the Plainfield Substation project from $22,164,495 (See Q4 2021 Report, Page 38) to $20,978,138?	$500,000 from the end of 2022 and was largely the result of the electrical PO being higher than estimated, slightly offset by Division actuals being lower than estimated.	
S-INF-11	**Reference Q1 2022 Report, Page 39, Table 21 – ES 2 Gas M&R Summary Status as of March 31, 2022** With reference to the Gas M&R projects, please refer to Table 21 which indicates that the Camden M&R project is included in Stipulated Base. Please reconcile this with PSE&G's recent Energy Strong II cost recovery filing (BPU Docket Nos. ER22110669 and GR22110670), Filed November 1, 2022), in which PSE&G requested accelerated cost recovery of Camden M&R project expenditures placed in-service through January 31, 2023.	PSE&G initially projected to seek accelerated recovery on the Mount Laurel, East Rutherford, and Westampton M&R Stations based on the schedule forecasts that projected these stations to be the first three in-service in the subprogram. However, due to subsequent schedule changes, the Camden M&R station achieved in-service status ahead of Mount Laurel, therefore PSE&G is requesting cost recovery on Camden M&R station in this recent filing. This is consistent with the Stipulation that provides the first $50.5 million in Gas M&R investments to be recovered through the accelerated recovery, with any prudently incurred costs beyond $50.5 million being applied to the Stipulated Base.	No change
S-INF-12	Regarding the Central Gas M&R project, please provide additional details describing the need to increase the project scope from two (2) buildings to four (4) buildings (as discussed in S-INF-16 of the IM's Q4 2021 Report).	The design refinement resulted in a change of heater technology from water bath to the more efficient glycol heaters that provide for lower emissions. The reduced emissions facilitate obtaining the Title V Air Permit. This technology change also included replacement of four additional heaters that are near end of life, so PSE&G replaced them all, thus allowing the project to benefit from the improved technology. The original office level scope included the replacement of only one water bath heater. PSE&G also determined that use of two additional buildings would better address safety and other operational requirements/concerns. One of the additional buildings houses the circulating glycol heaters and the other houses the heat exchangers and the flow control equipment that balances the flow between the pipeline companies.	No change
S-INF-13	**Reference Q1 2022 Report, Page 43, Section IV. Additional Information Following the end of the First Quarter of 2022** Please indicate if the three (3) fiber projects removed from the Program (Haddon Heights, Lehigh Avenue, Thirty-Second Street) will be conducted outside of the Program.	PSE&G has indicated that the Haddon Heights and Lehigh Avenue projects are being executed outside of the ES 2 Program under base capital funding, but are scheduled to be completed within the Program window. The Thirty-Second Street project has been cancelled and will not be executed at this time.	**Section IV.**
RCR-IM-1	With reference to page 3 of the Independent Monitor's Draft First Quarter 2022 Report, please provide an update to the Kingsland switchgear delivery delay.	The reference on page 3 speaks to a delay to the switchgear #1 for the Ridgefield 13kV project, which impacts Kingsland as the contingency switchgear currently being used on the Ridgefield 13kV project will be the permanent switchgear for Kingsland once the switchgear #1 is received on the Ridgefield 13kV project.	No change

ID #	Question/Comment	IM Response	Report Changes
		Regarding the delivery status of switchgear #1 for the Ridgefield 13kV project, as of the end of the first quarter it was forecasted for delivery on July 22, 2022, with the actual delivery taking place on August 24, 2022 (or approximately one more month of delay from the status as of the end of the first quarter of 2022).	
RCR-IM-2	With reference to page 3 of the Independent Monitor's Draft First Quarter 2022 Report, please explain if the other projects are affected by major equipment deliveries and how this may increase individual project costs.	Due to the material and resource availability issues impacting Powercon, PSE&G's switchgear manufacturer, the outstanding switchgear deliveries are all at risk. As of the end of the first quarter of 2022, the following projects had open switchgear deliveries: Meadow Road, Ridgefield 13kV (switchgear #1), Lakeside, Leonia (switchgear #2), Clay Street, Toney's Brook, Waverly, Woodlynne, Orange Valley, Front Street (contingency and permanent switchgears). The 4kV life cycle station upgrade projects are similarly at risk with their open deliveries, which as of the end of the first quarter of 2022, was each of these projects (aside from the contingency switchgear on Paramus that was delivered in July 2021). The impacts from equipment delivery delays varies project to project depending on when the switchgear is needed to support the construction schedule (some of these deliveries were originally scheduled for storage due to being planned to be received well ahead of the need date). Additionally, as delivery delays are realized, the workarounds or mitigation options vary by project, with some more capable of absorbing impacts by resequencing or working activities in parallel when possible. PSE&G indicated to the IM that to date there have been no cost increases resulting from the major equipment delivery delays as PSE&G has been able to reprioritize deliveries with its vendor in addition to utilizing project float and/or shifting project schedules. There remains a risk for any project with open deliveries that the delivery date continues to shift out, which eventually can extend the project duration and lead to additional costs.	No change
RCR-IM-3	With reference to page 5 of the Independent Monitor's Draft First Quarter 2022 Report, please indicate how the project risk and contingency current risk registers are tracked.	The individual project risk registers are updated monthly by the project teams and reviewed by the subprogram and program leads, with the total R&C amounts aggregated and tracked at the subprogram level. During estimate transitions, if a project's base estimate increases, funding from the R&C placeholder is released to the project to fund the additional amount (likewise, if the base estimate decreases, the variance is returned to the R&C placeholder.	No change
RCR-IM-4	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Clay Street Substation from $30.8 to $31.3 million.	**Table 12** shows the current estimate and forecast for the Electric Station Flood Mitigation projects. For Clay Street, the current estimate (revised Conceptual level) is $30.8 million and was approved in January 2022, while the current forecast is $31.3 million and reflects the change in status, conditions, and	**Section III.A.2.**

ID #	Question/Comment	IM Response	Report Changes
		assumptions that have occurred since that last estimate update, including specifically: • Additional civil work required (enlarging two manholes, extra shifts) ($0.5 million).	
RCR-IM-5	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Ridgefield 13kV Substation from $26.1 to $27.2 million.	The $1.1 million forecast increase on the Ridgefield 13kV project reported during the first quarter of 2022 was driven by: • More than anticipated dewatering and updated design of manhole modifications ($0.5 million); and, • More Division effort required on manhole expansion and circuits cutovers due to difficult of breaking back the duct bank (high strength concrete) and working around the energized circuits ($0.6 million).	**Section IIIA.11.**
RCR-IM-6	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Waverly Substation from $36.2 to $37.6 million.	The $1.4 million forecast increase on the Waverly project reported during the first quarter of 2022 was driven by: • Civil construction PO awarded higher than estimated ($1.3 million); and, • Cost of switchgear storage ($0.1 million).	**Section III.A.15.**
RCR-IM-7	With reference to Table 12 ES 2 Electric Substation Flood Mitigation Project Cost Status as of March 31, 2022, please explain the increase in the projected cost of the Woodlynne Substation from $21.3 to $24.3 million.	The $3.0 million forecast increase on the Woodlynne project reported during the first quarter of 2022 was driven by: • Material and civil construction POs higher than estimated and bids ($0.4 million); and, • Revised Division estimate ($2.6 million).	**Section III.A.16.**
RCR-IM-8	With reference to page 18 of the Independent Monitor's Draft First Quarter 2022 Report, please explain the individual project updates to the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage) that collectively resulted in a $15.0 million increase.	The reference on page 18 reflects a summary of the updated estimates for these Electric Station Flood Mitigation projects that are individually discussed in greater detail within the respective project subsection under **Section III.A.** The IM notes that of the collective $15.0 million estimate increase on these projects, $12.3 million stemmed from two projects specifically: Waverly, which increased $6.8 million; and Woodlynne, which increased $5.8 million. Details of these updated project estimates are discussed within **Section III.A.15.** and **Section III.A.16.**, respectively.	No change
RCR-IM-9	With reference to page 28 of the Independent Monitor's Draft First Quarter 2022 Report, please explain how many installed Fuse Savers have experienced communication issues and have any remote control units been replaced and what are the costs with projected repairs or replacement.	In total, PSE&G installed 113 Fuse Savers during its pilot program, of which 10 locations experienced communication issues. PSE&G installed the modified external antenna at each of these 10 locations, which resolved the communication issues. Design of the standard RCU (enclosure and components) was modified to include the provision to install an external antenna in the field where needed (which has been at approximately 10% of the locations). The costs associated with the modified units are approximately $1,100 per unit and these units also require slightly longer installation times, but this is not tracked separately.	**Section III.B.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>RCR-IM-10</td><td>With reference to Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of March 31, 2022, please explain the change in the subprogram risk and contingency total for Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Lakeside Avenue, Leonia, Market Street, Meadow Road, Orange Valley, Ridgefield 13kV, Ridgefield 4kV, State Street, Toney’s Brook, Waverly and Woodlynne Substations compared to Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of December 31, 2021 in Independent Monitor’s Draft Fourth Quarter 2021 Report.</td><td>A summary of the Electric Station Flood Mitigation project estimate updates from the prior status as of the end of 2021 to the status as of the first quarter of 2022 is provided below:

<table><tr><td></td><td>Base</td><td>R&C</td><td>Total</td></tr><tr><td>As of Dec. 2021</td><td>$339,800,000*</td><td>$49,200,000</td><td>$389,000,000</td></tr><tr><td>As of Mar. 2022</td><td>$347,200,000</td><td>$41,800,000</td><td>$389,000,000</td></tr><tr><td colspan="4">*-included $3.7 million as a placeholder (to match the Stipulation budget of $389 million), this was absorbed by the R&C balance in the updated estimates.</td></tr></table>
Early in 2022 PSE&G instituted a change in the way it manages the R&C for the Electric Station Flood Mitigation projects shifting from each project maintaining its own R&C funds to managing the R&C at the subprogram level. Prior to this shift, the projects’ R&C was updated at the time of an estimate transition (50% to 70% to 90%). This change allows PSE&G to manage the R&C month-to-month based on the current project risk registers, which are updated monthly by the project team and reviewed by the subprogram lead. When the individual projects go through an estimate transition any variance to the base estimate results in additional funds added to the R&C placeholder (if the base estimate decreased) or release of R&C to cover the increase in base.</td><td></td></tr>
<tr><td>RCR-IM-11</td><td>With reference to Table 20 ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022, please explain the subprogram risk and contingency total for Hamilton, Paramus, Plainfield, Woodbury and State Street Substations.</td><td>A summary of the Life Cycle Station Upgrade project estimate updates from the prior status as of the end of 2021 to the status as of the first quarter of 2022 is provided below:

<table><tr><td></td><td>Base</td><td>R&C</td><td>Total</td></tr><tr><td>As of Dec. 2021</td><td>$82,800,000</td><td>$19,600,000</td><td>$102,400,000</td></tr><tr><td>As of Mar. 2022</td><td>$96,900,000</td><td>$3,100,000</td><td>$100,000,000</td></tr></table>
For the purposes of internal budget allocations and authorizations, PSE&G has planned for a portion of the Life Cycle Station Upgrade projects to be funded through the Accelerated Recovery (Electric Station Flood Mitigation funding) as provided in the Stipulation (“If the Company determines the work on the 16 aforementioned substations identified in the flood mitigation subprogram can be completed under the $389 million investment ceiling associated with substations, PSE&G may reallocate any funds to those stations identified in the life cycle station upgrade portion of the petition for accelerated recovery.”).</td><td>Table 20</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
PSEG-1	Please indicate circuit cutovers continued on the Academy Street project during the first quarter of 2022 and that circuit cutovers will be completed in the second quarter of 2022.	This activity has been added to the Academy Street project discussion.	**Section III.A.1.** and **Table 11**
PSEG-2	Please indicate in **Table 11** that the Waverly project upcoming activities for the second quarter of 2022 include setting the 26kV switchgear and start of commissioning.	This activity has been added to the Waverly project discussion.	**Table 11**

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2022 SECOND QUARTER REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

JUNE 28, 2023

Table of Contents

I. Executive Summary 1
II. Program Status 6
A. Key Decisions 6
B. Program Management 7
C. Cost Assignments 7
D. System Performance 12
III. Project Status 12
A. Electric Station Flood Mitigation 12
B. Contingency Reconfiguration 27
C. Grid Modernization – Communication System 30
D. Grid Modernization – ADMS 36
E. Electric Stipulated Base 39
F. Gas M&R Station Upgrades 45

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems ..... ADMS

Advanced Metering Interface ..... AMI

Allowance for Funds Used During Construction ..... AFUDC

Architect and Engineer ..... A/E

Board of Public Utilities ..... BPU

Construction Work In Progress ..... CWIP

Costs of Removal ..... COR

Distribution Management System ..... DMS

Distributed Energy Resource Management System ..... DERMS

Distribution Supervisory Control and Data Acquisition ..... D-SCADA

Energy Strong 2 ..... ES 2

Fault Protection Analysis ..... FPA

Gas Metering & Regulating ..... Gas M&R

Geographic Information System ..... GIS

Henkels & McCoy ..... H&M

Independent Monitor ..... IM

Industrial Site Recovery Act ..... IRSA

Inside Plant ..... IP

Issued for Construction ..... IFC

Liquid Propane Air ..... LPA

Mobile Work Management System ..... MWMS

Open Systems International Inc. ..... OSII

Outage Management System ..... OMS

Outside Plant ..... OP

Outside Plant-Higher Design Standards ..... OP-HDS

Project & Construction ..... P&C

Protective Distribution System ..... PDS

Public Service Electric & Gas ..... PSE&G

Purchase Order ..... PO

Quality Assurance System ..... QAS

Record of Decision ..... ROD

Remote Terminal Unit ..... RTU

Risk and Contingency ..... R&C

Supervisory Control and Data Acquisition ..... SCADA

Transmission Fiber Infrastructure ..... TFI

Utility Review Board ..... URB

Value of Loss Load ..... VOLL

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the second quarter of 2022.

During the second quarter of 2022, the bulk of the spend within the ES 2 Program was within the subprograms with larger individual projects (Electric Station Flood Mitigation, Electric Stipulated Base, and Gas M&R). Within the Electric Station Flood Mitigation subprogram, eight projects remain in construction as of the end of the second quarter of 2022 (with Market Street completing its construction scope and Front Street commencing construction during the quarter). Four of these projects are forecasted to be placed in-service during the fourth quarter of 2022, with the remaining stations forecasted to be completed in 2023 or early 2024. Within the Electric Stipulated Base scope, four of the five projects are in construction (with pre-construction activities underway on the other project, State Street Outside Plant (OP)), all five of these projects remain forecasted to go in-service during the fourth quarter of 2022. On the Gas M&R subprogram, three of the projects continued construction during the second quarter of 2022, each of these three projects is forecasted to go in-service during the fourth quarter of 2022. This will leave the Mount Laurel and Paramus projects as the two remaining projects in the subprogram (following the earlier completion of the Westampton project). Updated project estimates were also prepared for the Gas M&R projects during the second quarter of 2022, which saw the overall subprogram estimate increase by $18.9 million as driven by scope and execution refinement, with larger impacts realized from limited front-end planning performed on the stations at the time of the ES 2 filing.

Within the other subprograms, Fuse Saver installations recommenced in the Contingency Reconfiguration subprogram following the earlier pilot program conducted in 2020-2021. The Fuse Saver installations are expected to continue through the end of 2023, with 1,641 units currently forecasted for this scope of work. Within the Grid Modernization – Communication System subprogram, primary efforts during the second quarter of 2022 continued to focus on completing the remaining fiber installations (seven remaining as of the end of the quarter) and the remaining substation remote terminal unit (RTU) retrofits (48 remaining as of the end of the quarter). A new Grid Modernization – Communication System subprogram estimate was also completed during the second quarter of 2022, with the fiber installation scope estimate increasing $3.0 million from the prior estimate based on the higher costs observed on completed projects and the wireless network and retrofits scope decreasing by $1.3 million from the prior estimate based on an updated number of radios planned for the subprogram. Within the Grid Modernization – ADMS subprogram, go-live was achieved on the ADMS platform in June 2022, the quality assurance system (QAS) environment was built in the Outage Management System (OMS) scope, and additional patches were competed in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope. An updated estimate was also prepared for the Grid

Modernization – ADMS subprogram during the second quarter of 2022, which resulted in the subprogram estimate increasing by $13.6 million from the prior estimate, with the increase driven by scope updates, extended schedules/resource requirements, and additional risk and contingency (R&C).

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast, Stipulation budget, and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of June 30, 2022

Subprogram	Q2 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Budget***
Electric Station Flood Mitigation	**$17,828,688**	**$157,676,463**	**$358,158,627**	**44%**	**Feb 2024**	**$389M**
Contingency Reconfiguration	**$2,123,126**	**$110,093,554**	**$145,612,679**	**76%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$3,225,559**	**$57,786,702**	**$66,279,811**	**87%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$8,230,861**	**$37,767,016**	**$53,479,258**	**71%**	**Dec 2022**	**$42.7M**
Electric Stipulated Base	**$13,592,008**	**$39,909,208**	**$99,102,305**	**40%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^	**$19,389,664**	**$51,429,779**	**$104,273,652**	**49%**	**Dec 2023**	**$101M**
Total*	**$64,389,907**	**$454,662,622**	**$826,906,331**	**55%**	**Feb 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast R&C in its forecasts for these projects. See **Table 11 and **Table 20** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*
***-Final in-service date.*
****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*
^-Includes both the ES 2 projects and the Stipulated Base gas projects.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending (before the Stipulated Base consideration), a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of June 30, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,404,971	69%	**10/19/2021**
2. Clay Street	$30,800,000	$10,783,240	35%	1/30/2023
3. Front Street^	$25,900,000	$3,670,971	14%	11/8/2023 (↓+13)
4. Hasbrouck Heights	$19,300,000	$11,967,537	62%	12/23/2022 (↑-32)
5. Kingsland	$6,400,000	$1,665,091	26%	10/4/2023 (↓+2)
6. Lakeside Avenue	$39,400,000	$1,756,207	5%	9/18/2023
7. Leonia	$24,900,000	$20,947,894	84%	12/13/2022 (↓+28)
8. Market Street	$29,100,000	$28,022,997	96%	**6/25/2021**
9. Meadow Road	$7,200,000	$1,652,591	23%	9/22/2023
10. Orange Valley	$14,700,000	$1,186,155	8%	12/29/2023
11. Ridgefield 13kV	$26,100,000	$21,957,130	84%	12/13/2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
12. Ridgefield 4kV	$20,800,000	$20,703,809	100%	**5/16/2021**
13. State Street	$19,600,000	$10,631,628	54%	12/19/2022
14. Toney's Brook	$16,200,000	$2,294,598	14%	4/17/2023 (↑-4)
15. Waverly	$36,200,000	$8,949,013	25%	2/27/2024 (↑-7)
16. Woodlynne	$21,300,000	$5,082,698	24%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

During the second quarter of 2022, there were no updated estimates approved for the Electric Station Flood Mitigation projects. The projects that are active in construction (Clay Street, Front Street, Hasbrouck Heights, Leonia, Ridgefield 13kV, State Street, Waverly, and Woodlynne) had the highest spend during the quarter. **Table 2** also shows that six of the sixteen projects had movement during the second quarter of 2022 in the forecasted in-service date, with three advancing and three slipping. Of these six projects, four had the forecasted in-service dates change by less than two weeks (Front Street, Kingsland, Toney's Brook, and Waverly). While the Hasbrouck Heights forecasted in-service date advanced 32 days from the prior quarter, driven by resequencing construction activities and better than expected progress, and the Leonia forecasted in-service date slipped 28 days, driven by delays to the 13kV switchgear #2 delivery that slipped from mid-May to an actual delivery of June 16, 2022. As previously reported, the Waverly final in-service date had improved following the receipt of the approved site plan, but remains outside the Program end date following the earlier site plan delays due to slips in the forecasted delivery of the 4kV switchgear for the project, with a current forecasted in-service date of February 27, 2024.

The IM has found nothing to date that would jeopardize the overall ES 2 Program being completed on budget, although most individual subprograms are forecasted near or above their Stipulation budgets. Additionally, schedule challenges, particularly on the Waverly substation and other projects with forecasted in-service dates near the Program end date that are at risk due to the delays on the switchgear deliveries will continue to warrant further monitoring by the IM to identify if the ES 2 Program will be completed within the defined timeline. At this time, the following projects have forecasted in-service dates near the end of the Program end date and have open switchgear deliveries: Front Street, Lakeside Avenue, Orange Valley, Waverly, and Woodlynne. For Waverly specifically, the forecasted delivery date for the 4kV switchgear slipped 11 days from the status as of the end of the prior quarter. As previously discussed, on a monthly basis, PSE&G reviews the project schedules and assesses opportunities to improve the schedule based on the current status and information available, including the current delivery projections for the remaining switchgear.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*

ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the second quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service. Next projects forecasted to go in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service by the end of 2022.
    - Contingency Reconfiguration: Fuse Saver installations recommenced in May 2022 with 13 units installed during the quarter (126 units installed on the Program in total out of a currently planned scope of 1,641 units).
    - Grid Modernization – Communication System: 85 substation RTU retrofits completed (bringing the total to 170 out of a total scope of 218 substations); seven fiber projects and one fiber cutover project remaining.
    - Electric Stipulated Base: Hamilton's substation battery was placed in-service during the quarter. Each life cycle station upgrade project is forecasted to go in-service by the end of 2022.
    - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations planned to go in-service by the end of 2022.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. While the overall Program's current cost forecast is below the Stipulation amount, the IM has observed cost increases realized on specific projects or aspects of the Program and found the majority of these increases stem from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram

forecasts as of the end of the second quarter of 2022 compared to the end of the prior quarter were as follows:

- Electric Station Flood Mitigation: subprogram forecast increased approximately $8.6 million (or 2.5%) to approximately $358.2 million.
- Contingency Reconfiguration: subprogram forecast increased approximately $339,000 (or 0.2%) to approximately $145.6 million.
- Grid Modernization – Communication System: subprogram forecast increased approximately $136,000 (or 0.2%) to approximately $66.3 million.
- Grid Modernization – ADMS: subprogram forecast increased approximately $10.0 million (or 22.9%) to approximately $53.4 million.
- Electric Stipulated Base: subprogram forecast increased approximately $0.5 million (or 0.5%) to approximately $99.1 million.
- Gas M&R: subprogram forecast decreased approximately $24.1 million (or -18.7%) to approximately $104.3 million.

As shown above, the biggest subprogram forecast changes during the second quarter of 2022 were in the Electric Station Flood Mitigation, Grid Modernization – ADMS, and Gas M&R subprograms. Within the Electric Station Flood Mitigation subprogram, this increase was primarily on the Clay Street, Kingsland, Orange Valley, and Waverly projects, each seeing construction awards higher than estimated, slightly offset by a scope reduction on the Lakeside Avenue project. Within the Grid Modernization – ADMS subprogram, the forecast increase reflected an updated estimate that detailed the scope and interface complexities in the project. Within the Gas M&R subprogram, the forecast decrease primarily reflected PSE&G removing the LPA scope on the Camden and Central projects from the ES 2 Program.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used During construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C.** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On April 19, 2023, a draft IM 2022 Second Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2022 Second Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

During the second quarter of 2022, there were no additional RODs issued. The current and pending RODs as of the date of this IM 2022 Second Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM*

Subprogram	Record of Decision	IM Comments
		2020 Third Quarter Report and additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of June 30, 2022, below itemizes the charges to COR for the second quarter of 2022, the first quarter of 2022 (for comparative purposes), total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 program through June 30, 2022.

Table 4 – ES 2 Program Costs of Removal as of June 30, 2022

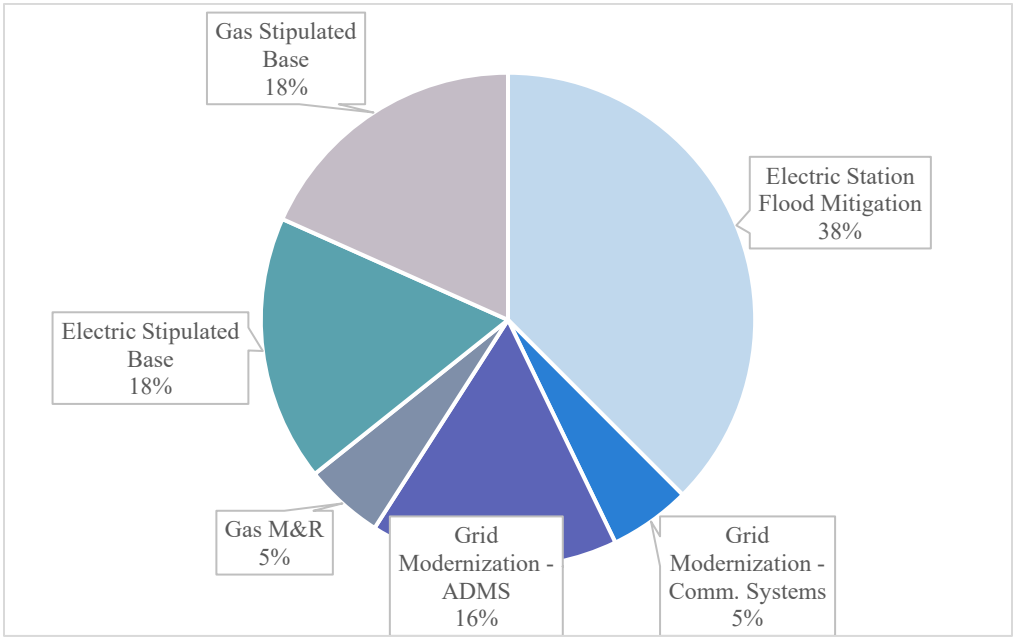
Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)						
Electric Station Flood Mitigation	$595.7	$873.4	$1,469.1	$5,558.7	$1,021.1	$0	**$8,048.9**
Contingency Reconfiguration	$35.7	$229.3	$265.0	$2,250.2	$2,198.9	$431.0	**$5,145.1**
Grid Modernization – Communications	$14.0	$11.0	$25.0	$137.8	$24.4	$0	**$187.2**
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0	**$0**
Electric Stipulated Base	$340.5	$370.0	$710.5	$150.0	$0	$0	**$860.5**
Gas M&R Station Upgrades	$0	($0.4)	($0.4)	$148.9	$0	$0	**$148.5**
Gas Stipulated Base	$0	$431.5	$431.5	$196.1	$0	$0	**$627.6**
Total	**$985.9**	**$1,914.8**	**$2,900.7**	**$8,441.7**	**$3,244.4**	**$431.0**	**$15,017.8**

The COR charges incurred on the Program for the second quarter of 2022 primarily reflect: (i) approximately $0.2 million of COR activities at the Ridgefield 13kV substation project for demolition of the bus system, disconnect switch, and feeder rows; (ii) approximately $0.2 million at the Leonia substation project for foundation demolition and underground cable removal; and (iii) approximately $150,000 of foundation and feeder row removal costs at the Paramus lifecycle project under the Electric Stipulated Base.

2. Construction Work-in-Progress (CWIP) & In-Service Transfers

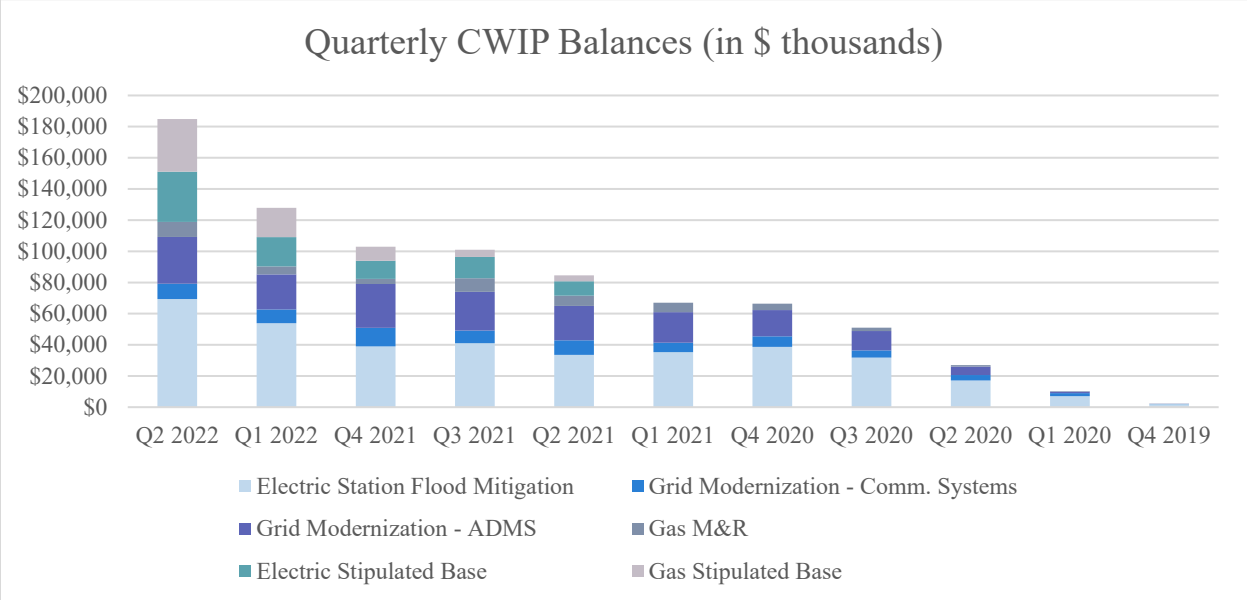
As of June 30, 2022, the ES 2 CWIP balance was $184.9 million, compared to $127.9 million as of the end of the prior quarter. The largest components of CWIP as of June 30, 2022 were the Hasbrouck ($12.4 million), State Street ($11.1 million), Clay Street ($11.0 million), and Waverly ($9.7 million) Electric Station Flood Mitigation projects; the Central ($18.8 million) and Camden ($13.7 million) Gas Stipulated Base M&R projects; the Hamilton ($10.5 million) and Plainfield ($7.9 million) substations under the Electric Stipulated Base; and, work associated with the ADMS subprogram ($30.0 million). The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of June 30, 2022** below.

Figure 1 – ES 2 CWIP as of June 30, 2022



In addition, **Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the second quarter of 2022, the first quarter of 2022, and each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022



	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Electric Station Flood Mitigation	$69,358	$ 53,834	$ 38,947	$ 41,077	$ 33,531	$ 35,299	$ 38,727	$ 31,860	$ 17,149	$ 7,101	$ 1,987
Grid Modernization - Comm. Systems	$ 9,872	$ 8,847	$ 11,991	$ 8,077	$ 9,343	$ 6,026	$ 6,760	$ 4,529	$ 3,508	$ 1,908	$ 75
Grid Modernization - ADMS	$30,010	$ 22,534	$ 28,057	$ 24,817	$ 22,085	$ 19,600	$ 16,837	$ 12,502	$ 5,428	$ 969	$ 36
Gas M&R	$ 9,642	$ 5,086	$ 3,338	$ 8,735	$ 6,574	$ 6,123	$ 4,032	$ 2,149	$ 951	$ 291	$ 53
Electric Stipulated Base	$32,179	$ 18,841	$ 11,560	$ 13,645	$ 9,280	$ -	$ -	$ -	$ -	$ -	$ -
Gas Stipulated Base	$33,854	$ 18,757	$ 9,042	$ 4,691	$ 3,808	$ -	$ -	$ -	$ -	$ -	$ -

Transfers from CWIP to plant in service were minimal during the second quarter of 2022, totaling approximately $0.1 million. Total ES 2 transfers from CWIP have been $86 million through June 30, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the second and first quarters of 2022, total 2022 to date, total AFUDC for the years 2021, 2020 and 2019, and total ES 2 AFUDC accrued to date, is shown below **Table 5 – ES 2 Program AFUDC as of June 30, 2022**.

Table 5 – ES 2 Program AFUDC as of June 30, 2022

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)						
Electric Station Flood Mitigation	$944.5	$759.0	$1,703.5	$2,281.2	$936.5	$9.9	**$4,931.1**
Contingency Reconfiguration	$0	$0	$0	$0	$0	$0	**$0**
Grid Modernization – Communications	$123.1	$115.6	$238.7	$386.9	$184.3	$0.2	**$810.1**
Grid Modernization – ADMS	$438.9	$385.7	$824.6	$1,365.6	$352.7	$0.1	**$2,543.0**
Electric Stipulated Base	$383.9	$230.0	$613.9	$524.6	$44.0	$0	**$1,182.5**
Gas M&R Station Upgrades (incl. Stip. Base)	$395.6	$208.3	$603.9	$470.0	$70.0	$0.2	**$1,144.1**
Total	**$2,286.0**	**$1,698.6**	**$3,984.6**	**$5,028.3**	**$1,587.5**	**$10.4**	**$10,610.8**

AFUDC accrued for ES 2 projects during the second quarter of 2022 increased over AFUDC accrued during the first quarter of 2022 as the result of increases in total average CWIP balances across all subprograms.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the second quarter of 2022, based on data as of June 30, 2022, the recalculated weighted average

AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the second quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to second quarter 2022 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. This Order was amended by a BPU Order dated June 8, 2022, allowing the company to transfer certain employees to the PSE&G Service Company in an effort to better support transmission growth opportunities and projects. This action had no impact on existing overhead allocations. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of June 30, 2022** are the allocated overhead costs charged to ES 2 subprograms for the second and first quarters of 2022 (for comparative purposes), 2022 year-to-date, total 2021, total 2020, total 2019, and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of June 30, 2022

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Electric Station Flood Mitigation	$2,208	$2,185	$4,393	$14,368	$14,023	$287	**$33,071**
Contingency Reconfiguration	$795	$843	$1,638	$14,420	$17,109	$3,415	**$36,582**
Grid Modernization – Communications	$717	$1,802	$2,519	$9,171	$3,625	$12	**$15,327**
Grid Modernization – ADMS	$124	$76	$200	$501	$426	$11	**$1,138**
Electric Stipulated Base	$1,275	$1,449	$2,724	$2,123	$259	$0	**$5,106**

Subprogram	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)						
Gas M&R Station Upgrades (incl. Stip. Base)	$339	$197	$536	$735	$291	$15	**$1,577**
Total	**$5,458**	**$6,552**	**$12,010**	**$41,318**	**$35,733**	**$3,740**	**$92,801**

The overwhelming majority of overhead costs allocated to ES 2 projects during the second quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 83%) of the second quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The decrease in overhead costs for the second quarter of 2022 from the first quarter of 2022 reflects primarily the decrease in spend on outside services and labor on Grid Modernization projects.

D. System Performance

1. Current Reporting Quarter Major Events

During the second quarter of 2022, there were no Major Events reported in PSE&G's service territory.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the second quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 7 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of June 30, 2022**. Note that the Market Street and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 7**).

Table 7 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of June 30, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023					2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
1. Academy Street	Dec. 2019		KO					C					IS		CO					*December 31, 2023 - ES 2 Program End*	
	Dec. 2020		KO		C									CO							
	Dec. 2021		KO		C						IS						CO				
	Jun. 2022		KO		C						IS		CO								
2. Clay Street	Dec. 2019	*Schedule Under Development*																			
	Dec. 2020			KO							C					IS					CO (Q2)
	Dec. 2021			KO							C				IS						CO (Q1)
	Jun. 2022			KO							C					IS					CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																			
	Dec. 2020	*Not in ES 2 Program*																			
	Dec. 2021								KO				C						IS		CO (Q2)
	Jun. 2022								KO				C						IS		CO (Q2)

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
	Jun. 2022		KO									C			IS			CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	
	Jun. 2022			KO									C						IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
	Jun. 2022						KO							C				IS		CO (Q1)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
	Jun. 2022			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
	Jun. 2022			KO											C			IS		CO (Q1)
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Jun. 2022					KO									C				IS	CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Jun. 2022			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
	Jun. 2022		KO						C						IS		CO			
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C			IS			CO (Q2)
	Jun. 2022			KO										C			IS		CO	

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
	Jun. 2022			KO			C													IS (Q1); CO (Q3)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)
	Jun. 2022		KO									C							IS	CO (Q2)

December 31, 2023 - ES 2 Progr

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout -Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the second quarter of 2022 is provided below **Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2022**.

Table 8 – ES 2 Electric Station Flood Mitigation Summary Status as of June 30, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	11	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Leonia; Market Street; Ridgefield 4kV; Ridgefield 13kV; State Street; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV

Activity	Total # of Projects	Specific Projects
Partial In-Service	2	Leonia; Ridgefield 13kV

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes projects that have commenced inside plant and/or outside plant construction; also maintains identification of projects that have since completed construction (generally those that are shown as in-service).*

Beyond the key activities summarized in **Table 8** above, **Table 9 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2022** summarizes the upcoming planned activities for each project during the third quarter of 2022, including any carryover of activities from earlier periods.

Table 9 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q3 2022

Station	Upcoming Activities for Q3 2022	Carryover Activities from Q2 2022
1. Academy Street	• Complete fiber cutover to new station	• Demo existing foundations, remove old equipment at existing Academy St. station
2. Clay Street	• Commence phase 1 civil work	• Commence pile driving
3. Front Street	• Manhole/trench work for contingency switchgear	• Continued civil construction (contingency switchgear)
4. Hasbrouck Heights	• Continued civil/electrical construction • Switchgear commissioning	• Switchgear assembly
5. Kingsland	• Commencing civil and electrical construction	• Issue electrical PO
6. Lakeside Avenue	• Commence civil construction	• Continued engineering
7. Leonia	• Install lightning mast, continued construction	• Complete switchgear #2 assembly
8. Market Street	*Project complete*	
9. Meadow Road	• Commence civil construction	• Civil and electrical POs issued
10. Orange Valley	• Issue civil and electrical POs • Commence civil construction	• Civil and electrical construction out for bid
11. Ridgefield 13kV	• Commence electrical construction	• Demo existing switchgear #1 (foundations)
12. Ridgefield 4kV	*Project complete*	
13. State Street	• Relay testing and commissioning switchgear	• Continued construction
14. Toney's Brook	• Commence civil construction	• Prepare for construction
15. Waverly	• Commissioning new switchgear • Demolition of existing switchgear	• Continued construction • Switchgear assembly
16. Woodlynne	• Continued engineering	• Continued engineering

As discussed in the IM 2022 First Quarter Report, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the remaining major equipment deliveries may continue to see impacts. PSE&G continues to receive weekly updates from Powercon on the current status of the deliveries and PSE&G's management visited Powercon's site in May 2022 with additional onsite visits planned. Powercon is exploring options to improve its production floor efficiencies and

ordering supplies earlier to potentially alleviate further impacts. PSE&G has requested more detailed and frequent status updates from Powercon to better inform its project planning, including details of Powercon's production schedules and information from its sub-vendors/suppliers. The status of the major equipment deliveries for the Electric Station Flood Mitigation projects is presented in **Table 10 – Electric Station Flood Mitigation Major Switchgear Deliveries as of June 30, 2022**.

Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022

Station	Description	Delivery Status as of Q1 2022	Delivery Status as of Q2 2022
1. Academy Street	13kV switchgear	***11/7/2020***	***11/7/2020***
2. Clay Street	4kV switchgear	6/16/2022	8/30/2022
3. Front Street	4kV switchgear	5/22/2023	5/22/2023
	4kV cont. switchgear	7/18/2022	7/17/2022
4. Hasbrouck Heights	4kV switchgear	***11/30/2021***	***11/30/2021***
5. Kingsland	13kV switchgear[1]	***9/30/2020***	***9/30/2020***
6. Lakeside Avenue	4kV switchgear	1/26/2023	1/26/2023
7. Leonia	13kV switchgear #1	***5/24/2021***	***5/24/2021***
	13kV switchgear #2	5/15/2022	***6/16/2022***
	13kV cont. switchgear[2]	***10/16/2020***	***10/16/2020***
8. Market Street	Elimination project		
9. Meadow Road	13kV switchgear[2]	1/3/2023	2/14/2023
10. Orange Valley	4kV switchgear	6/14/2023	5/29/2023
11. Ridgefield 13kV	13kV switchgear #1	7/22/2022	8/2/2022
	13kV switchgear #2	***4/27/2021***	***4/27/2021***
	13kV cont. switchgear[1]	***9/30/2020***	***9/30/2020***
12. Ridgefield 4kV	Elimination project		
13. State Street	4kV switchgear	***12/15/2021***	***12/15/2021***
14. Toney's Brook	4kV switchgear	12/21/2022	12/20/2022
15. Waverly	26kV switchgear	***4/30/2021***	***4/30/2021***
	4kV switchgear	7/25/2022	8/5/2022
16. Woodlynne	4kV switchgear	9/21/2022	11/22/2022

Note: bold/italicized dates indicate actual delivery dates.
[1]The Kingsland 13kV switchgear was delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project.
[2]The Meadow Road project will use the Leonia project's 13kV contingency switchgear as its permanent switchgear.

As shown in **Table 10**, as of the end of the second quarter of 2022, there were 10 switchgear deliveries outstanding for the subprogram, with one actual delivery realized during the quarter (the 13kV switchgear #2 for Leonia, which was received later than scheduled and led to the in-service date shift discussed in **Section III.A.7.**). The forecasted delivery dates for the remaining switchgear saw varying degrees of movement from the status at the end of the first quarter of 2022, with four of the 10 units seeing virtually no change, three seeing movement of less than one month (including Orange Valley's 4kV switchgear advancing), and three experiencing more significant slips, with Clay Street, Meadow Road, and Woodlynne each seeing the associated equipment delivery dates slip between 42 and 75 days, however this did not cause a change to the forecasted in-service dates for these projects at this time.

The current project estimates and forecasts are shown below in **Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2022**. As discussed in the IM 2022 First Quarter Report, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. Additionally, R&C funds are

released when projects transition estimate levels and during the second quarter of 2022 there were no updated estimates in the subprogram, thus the R&C balance remained unchanged from the prior quarter. **Table 11** also shows the current estimate level based on PSE&G's estimating processes and as approved by its Utility Review Board (URB), the actual spend, and percentage of actuals to estimate as of the end of the second quarter of 2022.

Table 11 – ES 2 Electric Station Flood Mitigation Project Cost Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$8,499,311	$6,404,971	69%
2. Clay Street	Conceptual	$30,800,000	$-	$30,800,000	$33,614,140	$10,783,240	35%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$26,155,627	$3,670,971	14%
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$18,923,124	$11,967,537	62%
5. Kingsland	Study	$6,400,000	$-	$6,400,000	$8,502,960	$1,655,091	26%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$34,900,034	$1,756,207	5%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$25,116,227	$20,947,894	84%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,291,584	$28,022,997	96%
9. Meadow Road	Study	$7,200,000	$-	$7,200,000	$8,285,425	$1,652,591	23%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$17,022,378	$1,186,155	8%
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$27,990,304	$21,957,130	84%
12. Ridgefield 4kV	Definitive	$20,800,000	$-	$20,800,000	$20,703,808	$20,703,809	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,838,101	$10,631,628	54%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,250,526	$2,294,598	14%
15. Waverly	Study	$36,200,000	$-	$36,200,000	$39,911,783	$8,949,013	25%
16. Woodlynne	Conceptual	$21,300,000	$-	$21,300,000	$24,153,365	$5,082,698	24%
ES 2 Station Placeholder	N/A	$-	$41,800,000	$41,800,000	$-	$-	-

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
Subprogram Total		**$347,200,000**	**$41,800,000**	**$389,000,000**	**$358,158,627**	**$157,676,463**	**41%**

**-As discussed in Section II.B. of the IM 2022 First Quarter Report, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- No change in completed projects during the second quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next projects forecasted to be placed in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each forecasted to go in-service during the fourth quarter of 2022.
- Six of the remaining thirteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the second quarter of 2022, with three advancing and three slipping. For four of those projects, the change was less than two weeks, with the biggest changes involving the following projects:
    - Hasbrouck Heights (advancing 32 days from January 23, 2023 to December 23, 2022); and
    - Leonia (slipping 28 days from November 15, 2022 to December 13, 2022).
- The overall subprogram forecast as of the end of the second quarter of 2022 increased $8.6 million (or 2.5%) to $358.2 million from the status as of the prior quarter. The forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $41.8 million in R&C). The change in the subprogram forecast was predominantly driven by changes to the project forecasts on five of the projects, including:
    - Kingsland (increased $2.1 million to $8.5 million): driven by civil and electrical construction awards higher than estimated and an increased quantity of piles based on the final design.
    - Lakeside Avenue (decreased $1.8 million to $34.9 million): electrical construction award lower than estimated (driven by scope reduction) and the transfer of the 4kV bus scope to the 69kV transmission project.
    - Clay Street (increased $2.3 million to $33.6 million): electrical construction award higher than estimated; equipment procurement higher than estimated; scope increases; and construction schedule recovery.
    - Waverly (increased $2.3 million to $39.9 million): civil construction award higher than estimated.
    - Orange Valley (increased $2.3 million to $17.0 million): civil construction award higher than estimated.

- With 44% of the subprogram forecast now spent (41% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget as even with some cost pressures on certain projects, there is adequate R&C remaining in the subprogram. However, the schedule status of the later projects in this subprogram, and in particular Waverly, will continue to be closely followed by the IM to monitor if the projects can be completed within the ES 2 Program window. At this time, the primary risk to the project schedule is the major equipment deliveries, followed by resource availability to support schedule requirements. Other projects currently forecasted to be in-service in the final quarter of the Program (fourth quarter of 2023) include: Front Street, Kingsland, Orange Valley, and Woodlynne.

- Concerning the major equipment deliveries, the primary issues appear to be continued supply chain challenges stemming from the Covid-19 and post-pandemic marketplace impacts, particularly with the sub-vendors to the switchgear manufacturer. In response to these unforeseen challenges, PSE&G has sought and received additional information and more frequent updates from its manufacturer, including conducting site visits to the fabrication facility. Based on the current information it receives, PSE&G assesses the project schedules and determines if there is any expected schedule impact from the delivery delays, and if so, if resequencing of activities or accelerating work is an option to recover the schedule. The IM is monitoring PSE&G's efforts in this regard to recover the schedule slippage and minimize any impacts to the overall Program completion.

- Relative to the Waverly project, as of the end of the second quarter of 2022, the project continues to show a final in-service date in 2024, now at February 2024, which has continued to show improvements as PSE&G details the schedule following the site plan approval in December 2021. The Waverly project has multiple major asset in-service dates for the 26kV switchgear, 4kV switchgear, and three transformers, which are currently forecasted from September 2022 (26kV switchgear) to February 2024 (Transformer #3). PSE&G has informed the IM that the project team will continue to assess the project schedule and will be examining the potential to shorten durations and/or work activities concurrently to pull the final in-service date back into 2023. The IM will continue to monitor the PSE&G efforts in this regard and will report on any recovery actions taken and how those actions assist in reducing the current slippage.

1. Academy Street

During the second quarter of 2022, $144,172 was spent on the Academy Street project compared to a forecast of approximately $135,000, which brought the total spend to approximately $6.4 million.

This project was placed in-service on October 19, 2021, and there were minimal activities performed during the second quarter of 2022. The elimination of equipment at the old substation site and related demolition activities are expected to commence and be completed in the second half of 2022.

The actual spend by quarter for Academy Street as compared to the current approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$150,398	$4,224,550	$1,754,789	$131,061	$144,172	$103,424	$1,948,915	$42,000

Actuals to Date	Estimate	% of Actuals to Estimate
$6,404,971	$9,300,000	69%

2. Clay Street

During the second quarter of 2022, $1,936,258 was spent on the Clay Street project compared to a forecast of approximately $2.7 million, which brought the total spend to approximately $10.8 million. The variance in forecasted to actual spend during the second quarter of 2022 was attributed to civil pile driving delayed (from May-June to June-July) due to the T3 contingency not being completed in April as initially planned and less foundation and duct bank work completed in June 2022 than originally planned. Part of this impact stemmed from a work standdown in June 2022 that was instituted in response to a reliability incident where the underground contractor excavating for new duct banks hit an obstruction (concrete at the top of an existing duct bank), which damaged two of the four pipes in the duct bank. This incident resulted in no injuries or customers impacted, and during the standdown PSE&G and the contractor reviewed safety and excavation procedures. Ultimately this had an approximate 10-day impact to the construction work on the project.

The forecast for the Clay Street project increased approximately $2.3 million from the prior quarter to a forecast of approximately $33.6 million as of the end of the second quarter of 2022. This forecast increase was driven by:

- Electrical construction award higher than estimated: $900,000;
- Construction schedule recovery due to permitting delays: $600,000;
- A/E procured equipment higher than estimated: $400,000;
- Addition of Human Machine Interface (HMI) to switchgear: $200,000; and,
- Requirement for a contingency capacitor bank: $200,000.

Despite less work completed in June 2022 than planned, the forecasted in-service date for the Clay Street project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the first quarter of 2022 at January 30, 2023.

The primary activities on the Clay Street project during the second quarter of 2022 included the receipt of the below grade construction permit and commencement of pile driving and civil works, which both began in June 2022.

The actual spend by quarter for Clay Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$116,409	$879,339	$2,806,593	$5,044,642	$1,936,258	$7,016,356	$6,276,325	$9,538,218

Actuals to Date	Estimate	% of Actuals to Estimate
$10,783,240	$30,800,000	35%

3. Front Street

During the second quarter of 2022, $889,533 was spent on the Front Street project compared to a forecast of approximately $904,000, which brought total spend to approximately $3.7 million. The forecasted in-service date for the Front Street project as of the end of the second quarter of 2022 slipped 13 days from the status as of the end of the first quarter of 2022 to November 8, 2023.

The primary activities on the Front Street project during the second quarter of 2022 included:

- Start of civil construction inside plant (IP) to prepare for the contingency switchgear;
- Final vendor controls drawings received (for the permanent switchgear); and,
- Electrical construction PO issued (with electrical construction expected to commence in August 2022).

The actual spend by quarter for Front Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$-	$-	$2,351,832	$429,607	$889,533	$4,980,522	$1,873,016	$16,631,118

Actuals to Date	Estimate	% of Actuals to Estimate
$3,670,971	$25,900,000	14%

4. Hasbrouck Heights

During the second quarter of 2022, $2,187,907 was spent on the Hasbrouck Heights project compared to a forecast of approximately $2.3 million, which brought the total spend to approximately $12.0 million. The forecasted in-service date for the Hasbrouck Heights project as of the end of the second quarter of 2022 advanced 32 days from the status as of the end of the first quarter of 2022 to December 23, 2022. This forecasted in-service date advancement was driven by a combination of re-sequencing the civil and electrical construction activities and better than expected electrical construction progress.

Notable activities completed during the second quarter of 2022 included:

- Commencement of electrical construction;
- Start of civil foundations and other civil IP work (grounding grid, trenches); and,
- Setting the switchgear.

The actual spend by quarter for Hasbrouck Heights as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,187,907	$1,702,906	$2,320,722	$2,931,960

Actuals to Date	Estimate	% of Actuals to Estimate
$11,967,537	$19,300,000	62%

5. Kingsland

During the second quarter of 2022, $538,096 was spent on the Kingsland project compared to a forecast of approximately $512,000, which brought the total spend to approximately $1.7 million. The forecast for the Kingsland project increased approximately $2.1 million from the prior quarter to a forecast of approximately $8.5 million as of the end of the second quarter of 2022. This forecast increase was driven by:

- Civil construction award higher than estimated: $1,500,000;
- Increase in piles based on final design: $300,000; and,
- Electrical construction award higher than estimated: $300,000.

The forecasted in-service date for the Kingsland project as of the end of the second quarter of 2022 remained nearly unchanged from the status as of the end of the first quarter of 2022, with two-day slip to October 4, 2023.

During the second quarter of 2022, primary activity on the Kingsland project was the civil and electrical work going out for bid, with the civil PO issued in June 2022. Civil and electrical construction are expected to commence in the third quarter of 2022.

The actual spend by quarter for Kingsland as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$104,112	$209,667	$510,943	$301,463	$538,906	$390,263	$2,357,731	$4,089,875

Actuals to Date	Estimate	% of Actuals to Estimate
$1,665,091	$6,400,000	26%

6. Lakeside Avenue

During the second quarter of 2022, $230,836 was spent on the Lakeside Avenue project compared to a forecast of approximately $159,000. The forecasted in-service date for the Lakeside Avenue project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at September 18, 2023.

Notable activities completed on the Lakeside Avenue project during the second quarter of 2022 included the civil PO being issued. Civil construction is expected to commence in the third quarter of 2022, followed by electrical construction commencing in the fourth quarter of 2022.

The actual spend by quarter for Lakeside Avenue as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Lakeside Avenue project decreased $1.8 million from the status as of the prior quarter to $34.9 million (shown in **Table 11**), which was driven by electrical construction award lower than estimated (in turn driven by scope reduction as initially planned elevated stairs and rigging of the switchgear was no longer required) and the transfer of the 4kV bus scope to the 69kV transmission project (based on the sections transferred being tied to the high-side bushings of the 69/4kV transformers, and as such considered a transmission asset under PSE&G's practices).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$148,943	$453,994	$570,713	$351,720	$230,836	$2,263,003	$1,656,432	$29,224,392

Actuals to Date	Estimate	% of Actuals to Estimate
$1,756,207	$39,400,000	5%

7. Leonia

During the second quarter of 2022, $3,968,355 was spent on the Leonia project compared to a forecast of approximately $3.98 million, which brought the total spend to approximately $20.9 million. The forecasted in-service date for the Leonia project as of the end of the second quarter of 2022 slipped 28 days from the status at the end of the first quarter of 2022 to December 13, 2022. This forecasted in-service date slip was driven by delivery delays on the switchgear.

Notable activities completed on the Leonia project during the second quarter of 2022 included:

- Completed the demolition of the existing feeder rows;
- Switchgear #2 circuits cutover to the temporary switchgear;
- Start of demolition of existing switchgear #2; and,
- The new switchgear #2 was received at site and set.

The actual spend by quarter for Leonia as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,968,355	$1,190,086	$1,147,384	$1,830,862

Actuals to Date	Estimate	% of Actuals to Estimate
$20,947,895	$24,900,000	84%

8. Market Street

During the second quarter of 2022, $202,619 was spent on the Market Street project compared to a forecast of approximately $221,000, which brought the total spend to approximately $28.0 million. The Market Street substation was taken out of service as of June 25, 2021.

Notable activities conducted during the second quarter of 2022 included the completion of civil demolition and the associated Industrial Site Recovery Act (IRSA) compliance activities.

The actual spend by quarter for Market Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$251,193	$16,079,601	$10,681,487	$808,096	$202,619	$181,588	$51,000	$36,000

Actuals to Date	Estimate	% of Actuals to Estimate
$28,022,997	$29,100,00	96%

9. Meadow Road

During the second quarter of 2022, $321,098 was spent on the Meadow Road project compared to a forecast of $273,000, which brought the total spend to approximately $1.7 million. The forecasted in-service date for the Meadow Road project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at September 22, 2023.

The primary activities conducted on the Meadow Road project during the second quarter of 2022 included:

- Civil, electrical, and controls drawings issued for construction (IFC); and
- Civil and electrical construction out for bid.

Civil construction is expected to commence in the third quarter of 2022, while electrical construction is currently forecasted to being in early 2023.

The actual spend by quarter for Meadow Road as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$63,128	$535,081	$445,234	$288,050	$321,098	$573,894	$1,415,692	$4,643,248

Actuals to Date	Estimate	% of Actuals to Estimate
$1,652,591	$7,200,000	23%

10. Orange Valley

During the second quarter of 2022, $276,614 was spent on the Orange Valley project compared to a forecast of approximately $241,000, which bought the total spend to approximately $1.2 million. The forecasted in-service date for the Orange Valley project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 29, 2023.

During the second quarter of 2022, major activities on the Orange Valley project included the civil and electrical work being issued for bid and the IFC release of the civil and electrical drawing packages. Civil construction is anticipated to commence in the third quarter of 2022, while electrical construction is currently forecasted to start in early 2023.

The actual spend by quarter for Orange Valley as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$77,029	$362,895	$358,052	$111,565	$276,614	$376,925	$708,865	$14,750,433

Actuals to Date	Estimate	% of Actuals to Estimate
$1,186,155	$14,700,000	8%

11. Ridgefield 13kV

During the second quarter of 2022, $2,557,679 was spent on the Ridgefield 13kV project compared to a forecast of approximately $2.5 million, which brought the total spend to approximately $22.0 million. The forecasted in-service date for the Ridgefield 13kV project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 13, 2022.

Notable activities performed during the second quarter of 2022 included:

- Relay setting information delivered to the IP construction relay group;
- New Switchgear #2 all circuit cutover completed;
- Existing switchgear #1 circuits cutover to the temporary switchgear;
- Completed demolition of the existing switchgear #1; and,
- Started civil construction for the new switchgear #1.

The actual spend by quarter for Ridgefield 13kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$205,982	$6,232,692	$10,849,681	$2,111,096	$2,557,679	$3,412,979	$1,816,195	$804,000

Actuals to Date	Estimate	% of Actuals to Estimate
$21,957,130	$26,100,000	84%

12. Ridgefield 4kV

During the second quarter of 2022, $14,405 was spent on the Ridgefield 4kV project compared to a forecast of $13,000, which held the total spend at approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project is essentially complete now with final closeout activities performed during the first quarter of 2022 that included some trailing costs in the second quarter of 2022.

The actual spend by quarter for Ridgefield 4kV as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$143,414	$11,239,534	$9,263,852	$42,604	$14,405	-	-	-

Actuals to Date	Estimate	% of Actuals to Estimate
$20,703,809	$20,800,000	100%

13. State Street

During the second quarter of 2022, $1,046,814 was spent on the State Street project compared to a forecast of approximately $1.07 million, which brought the total spend to approximately $10.6 million. The forecasted in-service date for the State Street project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the first quarter of 2022 at December 19, 2022.

Notable activities performed on State Street during the second quarter of 2022 included the continued advancement of civil and electrical construction.

The actual spend by quarter for State Street as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$77,590	$662,148	$8,093,227	$751,849	$1,046,814	$1,199,012	$1,885,426	$6,122,034

Actuals to Date	Estimate	% of Actuals to Estimate
$10,631,629	$19,600,000	54%

14. Toney's Brook

During the second quarter of 2022, $629,773 was spent on the Toney's Brook project compared to a forecast of approximately $110,000, which brought the total spend to approximately $2.3 million. The variance in forecasted to actual spend during the second quarter of 2022 was attributed to early delivery of steel platforms and standard shape structures that had previously been forecasted to arrive in July 2022.

The forecasted in-service date for the Toney's Brook project as of the end of the second quarter of 2022 advanced four days from the status as of the end of the first quarter of 2022 to April 17, 2023.

The primary activities on during the second quarter of 2022 involved preparations for construction, with civil and electrical construction both forecasted to commence in the third quarter of 2022.

The actual spend by quarter for Toney's Brook as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$211,940	$373,096	$941,519	$138,270	$629,773	$793,356	$5,704,738	$7,457,834

Actuals to Date	Estimate	% of Actuals to Estimate
$2,294,598	$16,200,000	14%

15. Waverly

During the second quarter of 2022, $1,536,375 was spent on the Waverly project compared to a forecast of approximately $1.5 million, which brought the total spend to approximately $8.9 million.

The forecasted in-service date for the Waverly project as of the end of the second quarter of 2022 continued to achieve advancements as the project team details the construction schedule following the site

plan approval in December 2021. The current forecasted in-service date advanced seven days from the status as of the end of the first quarter of 2022 to February 27, 2024.

The primary activities performed during the second quarter of 2022 included:

- Construction permits approved;
- Start of civil construction;
- 26kV switchgear set on foundation; and,
- Start of electrical construction.

The 26kV switchgear is currently forecasted to be placed in-service in September 2022.

The actual spend by quarter for Waverly as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$103,748	$2,460,815	$4,415,223	$432,853	$1,536,375	$8,643,675	$2,258,298	$20,060,797

Actuals to Date	Estimate	% of Actuals to Estimate
$8,949,014	$36,200,000	25%

16. Woodlynne

During the second quarter of 2022, $1,347,345 was spent on the Woodlynne project compared to a forecast of approximately $1.4 million, which brought the total spend to approximately $5.1 million. The forecasted in-service date for the Woodlynne project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the first quarter of 2022 at October 10, 2023.

The primary activities performed on the Woodlynne project during the second quarter of 2022 involved the continuation of civil construction that commenced in late February 2022. Electrical construction is currently forecasted to commence in early 2023.

The actual spend by quarter for Woodlynne as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$110,982	$993,298	$991,630	$1,639,443	$1,347,345	$972,053	$5,617,958	$12,480,656

Actuals to Date	Estimate	% of Actuals to Estimate
$5,082,698	$21,300,000	24%

B. Contingency Reconfiguration

During the first quarter of 2022, the final reclosers were installed and commissioned, completing this scope of the Contingency Reconfiguration subprogram and with the remaining work involving the installation of Fuse Saver devices. **Table 12 – ES 2 Program Fuse Saver Status as of June 30, 2022** provides a summary of the Fuse Saver scope of the Contingency Reconfiguration subprogram, indicating

the number of units completed during the second quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning out of a total scope of 1,641 units. This represents a reduction of 72 units in the forecasted number of units for the Program from the status as of the end of the first quarter of 2022 and follows PSE&G's approach on forecasting the Fuse Saver scope based on a quarterly review of the actual cost data and related installation status information to inform the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram.

Table 12 – ES 2 Program Fuse Saver Status as of June 30, 2022

Type	Engineering Packages Completed (1 Fuse Saver ea.)	Fuse Savers Installed	Fuse Savers Commissioned
Q2 Qty.	170	13	12
Program Total to Date	417	126	125
Remaining	1,224	1,515	1,516

The installation of Fuse Savers recommenced in May 2022, following the earlier installations performed as part of the Fuse Saver pilot program in 2020-2021. As shown in **Table 12**, installations in the second quarter of 2022 were limited to 13 devices, which was the result of a hold placed on installations after a technical issue was observed on a couple devices and installations not being performed in periods when a D-SCADA freeze was initiated. The technical issue involved voltage observed when the unit was in the open position, PSE&G sent back two units to Siemens for testing, which determined that the root cause was ghost or induced voltage (due to close proximity to a live conductor). PSE&G assessed potential safety hazards when the devices are in the open configuration and is considering a change in the measuring instrument, but cleared the installations to continue.

Regarding the D-SCADA freeze, PSE&G implemented a D-SCADA freeze in late April/early May 2022 and again in mid-June 2022, which was needed to support the Platform go-live milestone achieved in the Grid Modernization – ADMS subprogram. This was identified ahead of implementation of the D-SCADA freeze, but nonetheless resulted in an approximate two-week period where installations were not available. As a result, PSE&G intends to add more installations than initially planned in the third and fourth quarters of 2022 and also push some installations into 2023, though expects no significant cost impacts as a result of this shift.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2022**. This table also shows the forecasted final in-service dates as of the end of the first quarter of 2022 to show movement to the forecast as of the end of the second quarter of 2022.

Table 13 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of June 30, 2022

Scope & Division		Q1 2022 Forecasted Completion Date	Q2 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022 (Actual)	1/31/2022 (Actual)
	Metro	12/31/2021 (Actual)	12/31/2021 (Actual)
	Palisades	1/31/2022 (Actual)	1/31/2022 (Actual)
	Southern	1/31/2022 (Actual)	1/31/2022 (Actual)
Fu	Central	9/30/2023	12/30/2023

Scope & Division		Q1 2022 Forecasted Completion Date	Q2 2022 Forecasted Completion Date
	Metro	10/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	9/30/2023	12/30/2023

As shown in **Table 13**, the forecasted in-service dates for the Fuse Saver scope slipped for the Central, Metro, and Southern Divisions based on adjusted monthly distribution to account for the delays in installation encountered in the second quarter of 2022 as discussed above.

The Contingency Reconfiguration subprogram costs through the end of the second quarter of 2022 are presented in **Table 14 – ES 2 Contingency Reconfiguration Actual Costs as of June 30, 2022**.

Table 14 – Contingency Reconfiguration Actual Costs as of June 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Total to Date
		Actuals					
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$45,064	$25,566,400
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	($31,771)	$24,445,004
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$2,816	$22,851,572
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$4,112	$29,059,110
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$433,473	$2,336,767
	Metro	$7,557	$561,915	$507,742	$160,801	$298,329	$1,536,344
	Palisades	$7,468	$522,454	$577,113	$127,207	$656,533	$1,890,775
	Southern	$9,792	$859,014	$578,217	$245,990	$714,570	$2,407,583
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$1,824,151**	**$110,093,555**

Table 15 – Contingency Reconfiguration Forecasted Costs as of June 30, 2022 examines the forecast as of the end of the second quarter of 2022 for each Division's Fuse Saver scope compared to the total actual costs incurred through the end of the second quarter of 2022.

Table 15 – Contingency Reconfiguration Forecasted Costs as of June 30, 2022

Scope & Division		Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Reclosers	Central	$25,566,400	$25,575,700	$9,300	100%
	Metro	$24,445,004	$24,445,004	-	100%
	Palisades	$22,851,572	$22,851,571	-	100%
	Southern	$29,059,110	$29,059,110	-	100%
Fuse Savers	Central	$2,336,767	$10,532,401	$8,195,635	22%
	Metro	$1,536,344	$11,677,063	$10,140,719	13%
	Palisades	$1,890,775	$9,776,369	$7,885,594	19%
	Southern	$2,407,583	$11,695,459	$9,287,876	21%
Total		**$110,093,555**	**$145,612,679**	**$35,519,124**	**76%**

As shown in **Table 15**, the overall Contingency Reconfiguration subprogram was spent 76% of its current forecast. With the total forecast as of the end of the second quarter of 2022 increasing $339,407 from the status as of the end of the prior quarter.

Findings & Observations:

- Progress on the Fuse Savers scope of the subprogram began to ramp-up following the completion of the reclosers scope in the first quarter of 2022, but was limited due to a D-SCADA freeze and a technical issue encountered (and resolved) during the quarter. During the second quarter of 2022, an additional 170 Fuse Saver engineering packages were completed, 13 units installed, and 12 units commissioned; with a total of 125 units commissioned as of the end of the second quarter of 2022 out of a current scope of 1,641 units.

- The slower than planned progress during the second quarter contributed to revised in-service dates for the Fuse Saver scope of work following the adjustment of the monthly installation targets, with each Division now forecasted to complete the Fuse Savers scope by December 2023.

- The Contingency Reconfiguration subprogram forecast continued to remain relatively static as of the end of the second quarter of 2022, with the total forecast increasing by approximately $339K (or less than 0.0%) to $145.6 million. This is slightly above the Stipulation budget of $145.0 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the second quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers in the Contingency Reconfiguration subprogram.

- Fiber installations and cutovers: 27 out of 34 fiber installation projects completed and 11 out of 12 fiber cutover projects completed.

- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.

- Retrofitting RTUs: 170 substation retrofits completed (85 during the second quarter of 2022) out of a current scope of 218 substations.

PSE&G has planned the Grid Modernization – Communication System scope of work by grouping the wireless network and retrofit components into one estimate for approval before its URB and having a separate estimate for the fiber installations and cutovers scope. During the second quarter of 2022, PSE&G transitioned these estimates to the Definitive stage, which were approved by its URB in June 2022. **Table 16 – Grid Modernization – Communication System Estimate** shows the current Definitive stage estimate compared to the earlier Study and Office stage estimates.

Table 16 – Grid Modernization – Communication System Estimate

Scope	Item	Description	Cost
Fiber Installations & Cutovers	***Office Estimate***		***$23,400,000***
	New Fiber Scope Refinement	Substation and Operation Center fiber installation scope and estimates modified to align with current communication needs	$7,900,000
	Project Management, Licensing & Permitting, Engineering	Reduction in scope of Distribution Stations with existing fiber that still required communications to be cutover	($3,800,000)
	Study Estimate		***$27,500,000***
	Outside Plant Estimates	Actual costs higher than estimated for contracted work ($1.6 million) and work performed with internal resources ($0.9 million) based on scope and estimate refinement	$2,500,000
	Inside Plant Estimates	Office level estimates further refined	$2,200,000
	Changed Routes	Route changed in order to provide simplified design and avoid extensive inspections and permitting associated with original OP routes for Montclair (+$1.3 million) and Bloomfield (-$0.4 million).	$900,000
	Fiber Cutovers	Increase due to scope and estimate refinement	$300,000
	Scope Reduction	32nd Street, Howell Street, Waverly, Haddon Heights, and Lehigh Avenue stations removed from ES 2 Program	($2,900,000)
	Definitive Estimate		***$30,500,000***
Wireless Network & Retrofits	***Office Estimate***		***$48,600,000***
	FirstNet Wireless Network Solution	Selection of FirstNet as the wireless network solution in lieu of original plan to build a solely owned and operated private network	($13,500,000)
	Conceptual Estimate		***$35,100,000***
	Radio Reduction	387-unit reduction related to Fuse Savers, Retrofits, and Reclosers – including material and labor	($1,300,000)
	Definitive Estimate		***$33,800,000***
Total Grid Modernization – Communication System Definitive Estimate			**$64,300,000**

As shown in **Table 16**, since the initial Office estimate, the Grid Modernization – Communication System subprogram has seen cost adjustments primarily related to scope refinements and updated cost data. Overall, PSE&G has managed the subprogram to maintain its overall funding level (following the earlier transfer of $7.7 million to the Grid Modernization – ADMS subprogram), though cost pressures, particularly on the fiber installation projects have led the current forecast of $66.3 million to be slightly above the Definitive estimate of $64.3 million. PSE&G assessed the issues encountered to date with the Grid Modernization – Communication System subprogram and identified the following challenges and lessons learned:

- Changes in electric system and fiber communication availability at locations between the ES 2 filing and the BPU approval of the Program.
- Inadequate site investigations resulted in critical items being left out of initial scope definitions of IP (station batteries, facilities upgrade) and OP (underground/overhead splices) for various stations.
- Significant increase in construction duration resulting from time taken to obtain railroad permits and flaggers; lead time for scheduling Transmission Fiber Infrastructure (TFI) commissioning

resources; new outages required for splicing into fiber communication circuits supporting transmission line.
- Budget for ES 2 fiber projects was fixed with zero R&C.
- Lack of comprehensive review and updating of location requirements, grouping, and prioritizing locations for new fiber installation.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects were previously removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. During the second quarter of 2022, PSE&G assessed the remaining budget for the fiber scope and determined it would remove four additional projects from the planned list due to budgetary constraints (in addition to one of the removed stations, Waverly, having the IP fiber installation included as part of the Electric Station Flood Mitigation project at the substation). The list of identified fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of June 30, 2022**.

Table 17 – Fiber Projects by Division as of June 30, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street; Lehigh Avenue**	Elizabeth; Henry Street
Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street; Waverly**	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown; Haddon Heights**; 32nd Street**	Delair; East Riverton; Riverside; Mount Holly
Total	***38 projects***	***12 projects***
Projects underlined have been placed in-service.* *-Identified for removal from subprogram during Q2 2022.*		

During the second quarter of 2022 no additional fiber installation or fiber cutover projects were placed in-service. Thus, the total projects in-service as of the end of the second quarter of 2022 remained at 27 for the fiber installation projects and 11 for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of June 30, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the second quarter of 2022 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of June 30, 2022

Project Name	Q2 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Continued construction; township permit required to complete OP installation; verbal approval received in June 2022

Project Name	Q2 2022 Status
Bordentown	*In-Service (Q3 2021)*
Carteret	IP construction underway; submitted engineer-stamped drawings to railroad agencies
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	IP work preparation underway; awaiting railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Haddon Heights	Removed from subprogram
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	IP work preparation underway; railroad permits received for one of two OP runs
Lehigh Avenue	Removed from subprogram
Mechanic Street	Railroad permits received; Division scheduling work and railroad flaggers
Metro HQ	*In-Service (Q1 2021)*
Montclair	OP splices completed; TFI checklist submitted; router cut-in scheduled for July 2022
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	IP work preparation underway; railroad permit received, Contractor scheduling safety training and flagger support
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
Thirty Second Street	Removed from subprogram
Waverly	Removed from subprogram
West New York	*In-Service (Q1 2022)*
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*

Project Name	Q2 2022 Status
West Orange	Rack installation completed; in-service dependent upon Montclair substation being placed in-service (achieved in late June 2022), TFI checklist submitted and router cut-in scheduled for July 2022.
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	85 cutovers completed
-Project identified for removal from subprogram after the current reporting period, see **Section IV for additional information.*	

The Grid Modernization – Communication System subprogram costs by major period through the end of the second quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of June 30, 2022**, while **Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of June 30, 2022** provides the current forecasts as of the end of the second quarter of 2022 compared to the actual costs.

Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of June 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Total to Date
		Actuals					
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$186,505	$4,590,854
	Metro	$0	$818,620	$2,362,797	$135,374	$192,271	$3,509,045
	Palisades	$0	$825,174	$3,115,474	$186,059	$184,718	$4,311,425
	Southern	$0	$929,058	$3,862,816	$194,826	$193,249	$5,179,949
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$681,857	$10,657,317
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$347,002	$6,877,580
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$93,875	$6,401,660
	Southern	$4,731	$910,483	$2,466,477	$96,721	$33,229	$3,511,641
	Cutovers	$0	$876,502	$479,927	$49,907	$8,735	$1,415,071
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$99,655	$7,553,946
Substation RTU Cutovers		$0	$0	$127,129	$801,385	$920,534	$1,849,048
Bulk Purchase*		$0	$1,524,874	($520,766)	$641,029	$283,929	$1,929,066
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$3,225,559**	**$57,786,601**

**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of June 30, 2022

Scope & Division		Total to Date	Total Forecast	% of Actuals to Forecast
		Actuals		
Retrofit Reclosers	Central	$4,590,854	$6,639,697	69%
	Metro	$3,509,045	$5,553,635	63%
	Palisades	$4,311,425	$6,363,959	68%
	Southern	$5,179,949	$7,189,013	72%
Fiber	Central	$10,657,317	$11,237,905	95%
	Metro	$6,877,580	$7,613,808	90%
	Palisades	$6,401,660	$6,640,530	96%
	Southern	$3,511,641	$3,451,015	102%
	Cutovers	$1,415,071	$1,437,071	98%
Wireless Network		$7,553,946	$8,045,603	94%
Substation RTU Cutovers		$1,849,048	$2,107,575	88%
Bulk Purchase*		$1,929,066	$-	-

Scope & Division	Total to Date *Actuals*	Total Forecast	% of Actuals to Forecast
Total	**$57,786,601**	**$66,279,811**	**87%**
**-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*			

As shown in **Table 19**, actual costs incurred in the second quarter of 2022 were roughly half that incurred in the first quarter of 2022, which reflected much less work performed in the fiber scope due to the few projects remaining while the retrofit reclosers scope essentially mirrored the progress and costs seen in the first quarter of 2022. The forecasts shown in **Table 20** remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase).

Findings & Observations:

- The retrofit substation RTU scope continued to advance in the second quarter of 2022 following the ramp up in the first quarter of 2022, with an additional 85 substations completed during the quarter, bringing the total to 170 substations completed out of a currently forecasted scope of 218 substations.
- No additional fiber installation of fiber cutover projects were completed during the second quarter of 2022, leaving the total number of projects in-service at 27 for the fiber installation projects and 11 for the fiber cutover projects. The fiber scope still is expected to be completed by the end of 2022.
- The forecast for the Grid Modernization – Communication system subprogram remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase) to $66.3 million.
- PSE&G transitioned the two primary estimates generated for the subprogram (fiber installation & cutovers and wireless network & retrofits) to the Definitive stage. The fiber scope estimate increased by $3.0 million from the prior estimate, driven primarily by higher than estimated construction costs and scope changes. While the wireless network & retrofits scope estimate decreased by $1.3 million from the prior estimate due to a reduction in the number of radio units expected to be installed in the subprogram (that was in turn driven by a reduction in reclosers, Fuse Savers, and retrofit reclosers).
- Following the updated estimate, PSE&G identified the challenges and lessons learned from the subprogram's execution. With cost pressures driven by changes in the status of the sites from the ES 2 filing to the approval of the Program, further exacerbated by inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget. Scheduling commissioning resources and railroad flaggers was also identified as a challenge to project execution. These identified lessons learned were drivers to the increased costs, particularly in the fiber scope, and demonstrate some of the challenges in executing a group of similar, smaller sized projects that despite relatively common scopes (installing fiber), have unique station-specific requirements that are not identified until detailed engineering and site inspections take place.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the second quarter of 2022 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q2 2022 Activities:
    - Completed and provided Supervisory Control and Data Acquisition (SCADA) keys to Open Systems International Inc. (OSII) (forecast module).
    - Completed testing Fault Protection Analysis (FPA) module in Protective Distribution System (PDS).
    - Completed work on patching plan for FPA.
    - Compiled information for end user training.
    - Completed patch DERMS PDS.
- Forecasted Completion as of the end of the second quarter of 2022: 12/19/2022 (unchanged from Q1).

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tools for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. Ten (10) years' worth of existing OMS data will be migrated into the new system as well.
- Q2 2022 Activities:
    - Completed converted data and feedback sessions.
    - Combined PDS for Configuration.
    - Received code review approvals for Interfaces from Arch Review Board.
    - Attended onsite Mobile Work Management System (MWMS) Discovery Workshops and revised analysis.
    - Completed buildout of QAS environment.
    - Approved code review for SAP archive Job Dip.

- Approved design review for SAP claims and Geographic Information System (GIS) smart notes.
- Configured Compass PDS as part of Sprint 15.
- Identified variances in PDS environment and escalated to OSII.

- Forecasted Completion as of the end of the second quarter of 2022: 4/30/2023 (unchanged from Q1).

ADMS Platform

- Scope: Replace, enhance, and expand the existing D-SCADA platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q2 2022 Activities:
  - Completed training for Divisions and Relay Chiefs.
  - Completed Division workstations and monitor setups for cutover.
  - Completed buildout of management servers configuration.
  - Completed vulnerability migration.
  - Attempted go-live on 5/11/2022, identified and remediated defects and initiated go-live freeze on 6/15/2022, which was completed on 6/23/2022.
- Actual In-Service Date: 1/28/2022.

During the second quarter of 2022, PSE&G transitioned the Grid Modernization – ADMS subprogram estimate to the Definitive level. **Table 21 – Grid Modernization – ADMS Subprogram Estimate** shows the current Definitive stage estimate compared to the earlier Study and Office stage estimates.

Table 21 – Grid Modernization – ADMS Subprogram Estimate

Item	Description		Cost
Office Estimate			***$35,000,000***
Additional Interface and Hardware Requirements	During preliminary design, additional system integration and architecture requirements were identified since the original ES 2 filing		$5,400,000
Performance Testing	Due to lessons learned from Tropical Storm Isaias, additional performance testing scope was added to the project		$2,300,000
Conceptual Estimate			***$42,700,000***
OMS Scope Changes	*Detail of OMS Scope Changes*		$7,500,000
	Additional system architects – incremental need regarding amount of integration; underestimated due to intricacies with Mulesoft and various interfaces (SAP, Advanced Metering Interface (AMI), MWMS, Visualizations, etc.); outsourced original architect and acquired additional architect to meet the level of effort required	*$700,000*	
	Additional Distribution Operations Subject Matter Experts – Quality control; ex-Operational staff to test system; omitted from prior scope/estimates	*$400,000*	

Item	Description		Cost
	Additional Project Manager – required to manage complex infrastructure, systems integration, and compliance	*$400,000*	
	Additional GIS resources – due to availably challenges with current staff	*$500,000*	
	Additional Engineer and Architect – needed to support Platform integration with OMS; scope omitted from prior estimates	*$500,000*	
	Additional Project Coordinator – to assist Project Manager with coordinating deliverables and requirements due to increased level of effort needed to effectively manage execution	*$200,000*	
	Additional Controller – outsourced replacement for prior PSE&G controller	*$200,000*	
	Energy Cloud Governance – oversee and manage cross-program dependencies; implement best program management	*$1,100,000*	
	Organizational Change Management – right-sizing to program magnitude	*$500,000*	
	OSII scope changes – related to OMS, Visualizations, Compass, etc.; enhanced performance testing	*$2,600,000*	
	Additional Hardware	*$200,000*	
	Platform Delay – additional costs for rework and additional work required due to Platform delay	*$200,000*	
MWMS Delay	Due to the MWMS delay, schedules adjusted for alignment and resources extended		$3,300,000
R&C	Additional R&C		$2,800,000
Definitive Estimate			***$56,300,000***

As shown in **Table 21**, the Grid Modernization – ADMS subprogram estimate has increased $21.3 million since the initial Office level estimate. The changes summarized above that drove the cost increases generally relate to improving the product quality to match the company needs (including updated security requirements and application interfaces), enhancing the testing, additional staffing/program management, additional R&C, and impacts from the MWMS delay. PSE&G assessed the issues encountered to date with the Grid Modernization – ADMS subprogram and identified the following challenges and lessons learned:

- R&C should be included when estimating large and complex IT initiatives.
- IT projects differ from construction projects regarding risks and dependencies.
- Large and complex IT projects with significant dependencies on in-flight projects need greater levels of oversight/governance.
- Lack of project organization with understanding future projects within portfolio/strategy.
- Deficiency of proper resources in place and understanding future technologies.
- Organization change management is necessary when releasing new large and complex projects to gain user acceptance.

The Grid Modernization – ADMS subprogram costs through the end of the second quarter of 2022 are presented in **Table 22 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2022**.

Table 22 – ES 2 Grid Modernization – ADMS Costs as of June 30, 2022

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					***Forecast***		
$36,213	$16,447,624	$9,854,442	$3,197,877	$8,230,861	$3,235,879	$6,055,743	$6,420,617

Actuals to Date	Forecast	% of Actuals to Forecast
$37,767,018	$53,479,258	71%

Findings & Observations:

- The first of three primary ADMS components (the ADMS Platform) was placed in-service during the first quarter of 2022, with work in the second quarter of 2022 involving continued training and preparing workstations. The remaining DMS/DERMS and OMS scopes are continued to be forecasted to be placed in-service in December 2022 and April 2023, respectively.

- During the second quarter of 2022, PSE&G transitioned the Grid Modernization – ADMS subprogram estimate to the Definitive level, which saw the estimate increase by $13.6 million from the Conceptual level estimate (including an additional $2.8 million in R&C). The bulk of the estimate increase was attributed to scope and standardization changes reflecting the complexity of the OMS scope and aligning with updated security requirements and application interfaces. The subprogram forecast as of the end of the second quarter of 2022 similarly increased from the prior quarter, with the total forecast now at $53.5 million.

- Based on the challenges experienced in planning and estimating the ADMS scope of work, PSE&G appropriately identified lessons learned that will help it plan and prepare for future IT-type projects that differ in approach from typical construction projects. While both construction projects and IT/software projects can both be extremely complex, with many interfaces and different stakeholders among the common complexities, IT/software projects often have a higher degree of dynamism, or rate of change, compared to typical construction projects that can require different project management approaches.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric Outside Plant-Higher Design Standards (OP-HDS) and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] The OP-HDS scope continues to advance engineering ahead of construction commencing in the third quarter of 2022; the OP-HDS work is expected to continue through December 2023. The OP-HDS scope currently contemplates upgrades to approximately 40-50 circuit miles and replacement of approximately 700 poles. Initial selection of circuits for OP-HDS investments is based on the Value of Loss Load (VOLL) based on the highest annual VOLL from 2010-2020 over the baseline performance, while final circuit selection will reflect the VOLL rankings with the execution requirements driven by field conditions in an effort to maximize the customer benefit.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

to the life cycle scope. During the second quarter of 2022, PSE&G advanced the Hamilton, Plainfield, and Woodbury project estimates to the Definitive level. The five life cycle station upgrade projects and their current estimate compared to the actuals to date are provided in **Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022**.

Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Definitive	$16,800,000	-	$16,800,000	$10,363,391	62%	10/5/2022 (↑ -23)
2. Paramus	Conceptual	$20,500,000	-	$20,500,000	$14,804,042	72%	11/3/2022 (↑ -11)
3. Plainfield	Definitive	$22,600,000	-	$22,600,000	$8,631,746	38%	11/28/2022 (↓ +20)
4. Woodbury	Definitive	$18,100,000	-	$18,100,000	$5,402,352	30%	12/30/2022
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$707,678	4%	12/19/2022
ES 2 Station Placeholder	-	-	$2,300,000	$2,300,000	-	-	-

**-As discussed in the IM 2022 First Quarter Report, during the first quarter of 2022, PSE&G made the decision to hold R&C at the subprogram level.*

***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 23**, of the five life cycle station upgrade projects, the Plainfield project saw its forecasted in-service date advance during the second quarter of 2022, while the Hamilton and Woodbury projects saw their respective forecasted in-service dates slip during the second quarter of 2022. Overall, these shifts in forecasted in-service dates were relatively minor, with all five of the life cycle station upgrade projects still forecasted for completion by the end of 2022. The R&C balance as of the end of the second quarter of 2022 decreased by $0.8 million from the prior quarter, with these R&C funds being allocated to the base estimate for Hamilton ($600K) and Woodbury ($300K), slightly offset by a reduction to the base estimate for Plainfield (-$100K) with those funds returning to the R&C balance. Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Similar to the Electric Station Flood Mitigation subprogram, the life cycle station upgrade projects within the Electric Stipulated Base have started to experience delays to the forecasted delivery dates of the major equipment. The status of the major equipment deliveries for the Electric Stipulated Base projects is presented in **Table 24 – Electric Station Flood Mitigation Major Switchgear Deliveries as of June 30, 2022**.

Table 24 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022

Station	Description	Delivery Status as of Q1 2022	Delivery Status as of Q2 2022
1. Hamilton	4kV switchgear	4/5/2022	***4/5/2022***
2. Paramus	4kV switchgear	5/16/2022	***5/31/2022***
	4kV cont. switchgear	***7/8/2021***	***7/8/2021***
3. Plainfield	4kV switchgear	7/27/2022	8/26/2022
4. Woodbury	4kV switchgear	7/20/2022	7/20/2022
Note: bold/italicized dates indicate actual delivery dates.			

As shown in **Table 24**, the Hamilton and Paramus projects received their respective 4kV switchgears during the second quarter of 2022 (with Paramus having previously received a contingency switchgear to support the construction plan). For the remaining deliveries, both Plainfield and Woodbury are forecasted for the third quarter of 2022, with the Plainfield delivery slipping approximately one month from the status as of the end of the prior quarter.

Findings & Observations:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which is expected to commence construction in the fourth quarter of 2022).
- There was little movement in the forecasted in-service dates for three of the five life cycle upgrade projects during the second quarter of 2022, with Hamilton and Paramus slipping 23 and 11 days, respectively, and Plainfield advancing 20 days. Each of the five life cycle upgrade projects is currently forecasted to be in-service during the fourth quarter of 2022.
- The cost forecasts for the five life cycle upgrade projects collectively increased by approximately $0.5 million (or 0.5%) from the status as of the end of the first quarter of 2022 to a total forecast of $99.1 million as of the end of the second quarter of 2022. This increase was predominantly accounted for within the Paramus and Plainfield projects, while the Woodbury project saw a forecast decrease and Hamilton and the State Street OP projects had very minor forecast changes.
- Updated estimates were approved during the second quarter of 2022 on the Hamilton, Plainfield, and Woodbury projects, each of which advanced to the Definitive estimate stage and each saw the base estimate increase by $100K to $600K, with the primary drivers relating to higher than estimated construction costs.

1. Hamilton

During the second quarter of 2022, $3,089,239 was spent on the Hamilton project against a forecast of approximately $3.1 million. This brought total spend on the project to approximately $10.4 million through the end of the second quarter of 2022. The forecasted in-service date for the Hamilton project advanced 23 days from the status as of the end of the first quarter of 2022 to October 5, 2022. This forecasted in-service date advancement was driven by commissioning starting earlier than expected due to better than expected construction progress.

Notable activities performed during the second quarter of 2022 included the delivery of the regulators to complete the Powercon switchgear delivery and the commencement of electrical construction with the substation’s battery being placed in-service in May 2022.

During the second quarter of 2022, PSE&G advanced the Hamilton estimate to the Definitive stage, which resulted in the base estimate increasing by $600K to $16.8 million. This increase was driven by:

- $0.3 million: higher than estimated Division costs for design change on manholes and cable work;
- $0.2 million: higher testing and commissioning costs based on refined scope for underground cutover work;
- $0.2 million: higher than previously estimated bill of materials award. And,
- ($0.1 million): lower carrying costs based on actual trend.

The actual spend by quarter for Hamilton as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$0	$362,372	$3,141,022	$3,770,758	$3,089,239	$2,115,676	$2,342,184	$2,089,733

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$10,363,392	$16,800,000	$16,910,986	61%

2. Paramus

During the second quarter of 2022, $5,942,564 was spent on the Paramus project against a forecast of approximately $6.2 million. This brought total spend on the project to approximately $14.8 million through the end of the second quarter of 2022. The forecasted in-service date for the Paramus project advanced from November 14, 2022, as of the end of the first quarter of 2022, to November 3, 2022, as of the end of the second quarter of 2022.

Notable activities conducted during the second quarter of 2022 on the Paramus project included the commencement of IP civil and electrical construction, which included:

- Civil construction efforts included installation of foundations, duct banks, conduits and cable tray, and the grounding grid.
- Electrical construction efforts included the assembly of the 4kV switchgear (delivered at the end of May 2022) and the start of prepping and pulling cable to the new switchgear.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$0	$840,200	$7,068,765	$952,513	$5,942,564	$1,711,285	$1,217,431	$3,597,807

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$14,804,042	$20,500,000	$21,330,565	69%

3. Plainfield

During the second quarter of 2022, $2,682,840 was spent on the Plainfield project against a forecast of approximately $3.1 million. This brought total spend on the project to approximately $8.6 million through the end of the second quarter of 2022. The forecasted in-service date for the Plainfield project as of the end of the second quarter of 2022 slipped 20 days from the status as of the prior quarter to November 28, 2022. This forecasted in-service date slip was driven by delivery delays on the switchgear.

Notable activities conducted during the second quarter of 2022 included:

- Installation of new manholes;
- Installation of foundations and duct banks; and,
- Completion of the demolition of the existing feeder rows (started in the first quarter of 2022).

During the second quarter of 2022, PSE&G advanced the Plainfield estimate to the Definitive stage, which resulted in the base estimate decreasing by $100K to $22.6 million. This decrease was driven by:

- $0.9 million: Civil and electrical construction awards higher than previously estimated ($0.2 million and $0.7 million, respectively); and,
- ($1.0 million): Lower than estimated actual costs for Division overhead (-$0.6 million) and updated underground estimate based on current construction sequence (-$0.4 million).

The actual spend by quarter for Plainfield as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$0	$682,325	$3,584,101	$1,682,480	$2,682,840	$8,827,318	$1,803,873	$3,785,103

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,631,745	$22,600,000	$23,048,040	37%

4. Woodbury

During the second quarter of 2022, $1,776,838 was spent on the Woodbury project against a forecast of approximately $1.6 million. This brought the total spend on the project to approximately $5.4 million through the end of the second quarter 2022. The forecasted in-service date for the Woodbury project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the prior quarter at December 30, 2022.

Notable activities conducted during the second quarter of 2022 included:

- Completion of the duct banks from the station property line to OP manholes;
- Completion of the switchgear foundation;
- Installation of cable trench;
- Installation of the grounding grid; and,
- Site restoration and installation of station driveways.

During the second quarter of 2022, PSE&G advanced the Woodbury estimate to the Definitive stage, which resulted in the base estimate increasing by $300K to $18.1 million. This increase was driven by:

- $1.2 million: higher than estimated civil construction award ($1.1 million) and electrical supervision estimate ($0.1 million);
- $0.4 million: higher engineering estimate due to additional design and engineering needed for guidelines, SCADA updates, manhole access, and perimeter wall updates;
- $0.3 million: higher than estimated award for station wiring; and,
- ($1.6 million): Division estimate refinement after field verifications and preliminary engineering completed.

The actual spend by quarter for Woodbury as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$0	$551,165	$1,613,823	$1,460,525	$1,776,838	$6,444,584	$2477,880	$3,775,253

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$5,402,351	$18,100,000	$18,100,069	30%

5. State Street (Outside Plant)

During the second quarter of 2022, $101,527 was spent on the State Street (OP) project against a forecast of approximately $572,000. The variance between forecasted and actual spend in the second quarter was driven by delays in reaching an agreement with Camden County on restoration efforts, which caused permit delays and delays to the test pits work. The County had requested PSE&G use concrete and doweling for the temporary patching of the roadways following the test pits, but PSE&G advised the County that it would be installing manholes and duct banks in this area in the immediate future, which would make use of concrete for the temporary patching excessive. After additional discussions, the County and PSE&G reached an agreement to forego the use of concrete for the temporary patching (with a provision that if there is a failure, any repair would utilize concrete). PSE&G expects no additional costs associated with this effort, but the delay in permit approval is expected to affect the schedule, which is being evaluated. As of the end of the second quarter of 2022, the forecasted in-service date for the State Street OP project remained unchanged from the status as of the prior quarter at December 19, 2022.

Notable activities conducted during the second quarter of 2022 included the continuation of detailed engineering and outreach to the local municipalities concerning the underground work (test pits) that are expected to commence in the third quarter of 2022.

The actual spend by quarter for State Street (OP) as compared to the current URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$0	$0	$211,247	$395,903	$100,527	$1,529,615	$2,933,398	$14,541,955

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$707,677	$19,700,000	$19,712,645	4%

F. Gas M&R Station Upgrades

During the second quarter of 2022, PSE&G submitted updated estimates for each of the Gas M&R projects for approval by the URB. As part of this effort, the Camden, Central, East Rutherford, and Mount Laurel projects advanced the Conceptual level estimate, while Paramus and Westampton remained at the Study and Definitive stages, respectively. **Table 25 – ES 2 Gas M&R Summary Status as of June 30, 2022** below provides these newly approved estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 25 – ES 2 Gas M&R Summary Status as of June 30, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden*	Conceptual	$18,500,000	$3,300,000	$21,800,000	$13,467,350	62%	Dec 2022
2. Central*	Conceptual	$31,400,000	$5,500,000	$36,900,000	$19,046,123	52%	Nov 2023
3. East Rutherford	Conceptual	$21,700,000	$4,300,000	$26,000,000	$8,279,623	32%	Dec 2022
4. Mount Laurel	Conceptual	$12,700,000	$3,100,000	$15,800,000	$1,073,372	7%	Nov 2023
5. Paramus*	Study	$11,500,000	$8,400,000	$19,900,000	$1,250,390	6%	Dec 2023
6. Westampton	Definitive	$8,400,000	$-	$8,400,000	$8,312,921	99%	*Oct 2021 (actual)*
Subprogram Total		**$104,200,000**	**$24,600,000**	**$128,800,000**	**$51,429,779**	**40%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

Collectively, the updated estimates resulted in the overall subprogram estimate increasing by $18.9 million, or 17%, from the prior estimates. While details of the individual estimate changes are discussed within the individual project discussions that follow, PSE&G reviewed its estimating process including conducting a deep dive into the drivers to the changes from the Office level estimates and found:

- The original ES 2 filing estimates were completed in January 2018 and included seven projects totaling $136 million. The Stipulation as approved in September 2019 provided six stations at a total of $101 million, which saw the lowest priority station eliminated along with R&C being reduced from 60% to 35% and an additional 15% cut from the subprogram.
- There was insufficient investigation in the development of the projects during front-end planning to support the BPU filing (i.e. project scope not locked, lack of constructability review, final site layout incomplete).
- The upfront scope development did not consider design and execution refinement, resulting in deviation from the preliminary scope as formal scope lockdown for these projects did not occur.
- The R&C was insufficient and did not cover the final scope definition thereby leading to cost increases throughout the estimate phases.
- Front-end planning activities were not completed, nor were all stage gates met when Study level estimate were developed by the project teams with A/E firm assistance and submitted to the URB.
- Comparative estimates were not developed to support the review of the A/E estimates to ensure consistency.

- Scope items, such as Liquid Propane Air (LPA) systems at Camden and Central, scrubber improvements at Central and line strainers at each site were added, expanding upon the original BPU filing scope to take advantage of the mobilization on these projects, and then later carved out upon further evaluation, ensuring alignment with the filing.
- A more experienced project team executed ES 1, which were less complex stations, mitigating potential impacts due to lack of front-end planning within the existing processes. The current ES 2 stations are more complex and being managed by a less experienced project team, highlighting the need for a more formalized front-end planning process.
- Due to Covid-19, material price inflation as per market conditions contributed to increased material costs.

PSE&G also identified actions to implement to avoid this issue in the future, including:

- Evaluate and modify the existing Gas M&R project origination process:
    - Implement changes to the more closely model the electric project origination process.
    - Further develop gas expertise to perform feasibility analyses, further develop the design, and perform constructability analyses.
    - Better define project scope in the origination process to minimize undocumented scope evolution.
- Develop and expand Gas M&R expertise in the Projects & Construction (P&C) estimating group:
    - P&C estimating group has expanded to include gas projects.
    - Project teams have supplied the P&C estimating group with information as prices are received (materials, construction, etc.).
    - Benchmark with Gas Construction estimating group, Gas Asset Management and A/E firms subject matter experts to expand and support the gas estimating program.
- Implement the modified project origination process and expanded expertise.
- For future programs, if the settlement value is materially different than the filing, there needs to be a review to see if the original project scope is still achievable under the proposed settlement amount.

In consideration of the above, the IM has reviewed PSE&G's recommendations to award for the construction contractor scope of the Gas M&R projects awarded to date (all except Mt. Laurel and Paramus). A summary of this review is provided as follows:

- Camden: Henkels & McCoy (H&M) selected as the construction contractor after receiving the highest evaluated score (combined technical, commercial, and supplemental aspects) of the three contractors that submitted bids. H&M had the second lowest price (1.4% above the lowest bid, but 21.5% below the highest bid), but had a higher overall score due to their experience with similarly complex projects and their ability to meet the schedule and resource requirements.

- Central: H&M selected as the construction contractor after receiving the highest evaluated score of the three contractors that submitted bids. In addition to having the requisite experience and capabilities, H&M was the lowest bidder on this project (12.5% and 59% below the other bidders).

- East Rutherford: J. Fletcher Creamer selected as the construction contractor after receiving the highest evaluated score of the four contractors that submitted bids. In addition to having the requisite experience and capabilities, J. Fletcher Creamer was the lowest bidder on this project (52% to 102% below the other bidders).

- Westampton: H&M selected as the construction contractor after receiving the highest evaluated score of the five contractors that submitted bids. In addition to having the requisite experience and capabilities, H&M was the lowest bidder on this project (3.5% to 84% below the other bidders).

Relative to the forecasted in-service dates shown in **Table 25**, as of the end of the second quarter of 2022, the forecasted in-service dates for the remaining Gas M&R projects remained unchanged from the status as of the end of the prior quarter. As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The six projects that comprise the Gas M&R subprogram continues to advance at various stages of development or delivery. During the second quarter of 2022, construction continued to advance on the Camden, Central, and East Rutherford projects, while the Mount Laurel and Paramus projects continued pre-construction activities including advancing design efforts and receiving the interconnection agreement with Transco. The Westampton project was previously put in-service in October 2021, while punch list items and site restoration activities continued in the second quarter of 2022.

- There were no changes to the forecasted in-service dates of the Gas M&R projects during the second quarter of 2022. The next projects to be completed are the Camden and East Rutherford projects, which are forecasted to be placed in-service by the end of 2022.

- PSE&G updated the estimates for each of the Gas M&R projects during the second quarter of 2022, resulting in the overall subprogram estimate increasing by $18.9 million. While the Camden and Westampton project estimates decreased, the other stations within the subprogram saw estimate increases ranging from $4.4 million to $9.5 million. The estimate increases were generally related to design evolution, scope refinement, and current market conditions, which were more impactful due to the reduction in R&C from the original ES 2 filing to the approved Stipulation (reducing R&C from 60% to 35%). Despite these estimate increases, the overall subprogram forecast was reduced to $104.3 million (from $128.3 million as of the end of the first quarter of 2022) and remains below the current total estimate of $128.8 million, with the difference between the forecast and the estimate primarily reflecting the R&C funds.

- With the significant increase in the updated project estimates, the IM finds that PSE&G appropriately assessed why and how the project cost estimates have changed since the filing including identifying lessons learned and actions to be taken on future initiatives. Generally speaking, the increases were driven by scope refinement and market conditions, further exacerbated by the budget and R&C reduction from the ES 2 filing to the approved Stipulation.

- The IM has found nothing to date that would jeopardize the subprogram being completed on time, however, the current forecast of $104.3 million exceeds the Stipulation budget of $101.0 million.

1. Camden

During the second quarter of 2022, $7,655,276 was spent on the Camden project compared to a forecast of approximately $9.1 million, which brought the total spend to approximately $13.5 million. The variance in forecasted to actual spend in the second quarter of 2022 was attributed to delayed delivery of material to site due to availability from the sub-vendors. Despite these material delays, PSE&G has held

the forecasted in-service date for the Camden project at December 16, 2022 by re-sequencing certain activities and implementing contingency plans such as working with Transco to tie-in on their facility upstream of the pressure regulators and using a valve to connect to the new M&R station, this allows the old station to remain operating until the new station is ready and can make the cutover without taking a two to three day outage. PSE&G anticipates this contingency plan will require minor amounts of additional piping and minimal valve costs, but should not have a material impact on the project cost.

Notable activities on the Camden project during the second quarter of 2022 included:

- Contractor mobilized and began receiving materials;
- Soil conservation measures installed;
- Excavation for building footings and foundations;
- Pipe fabrication;
- Steel erection for regulator, heater, and control buildings;
- Installation of meter runs in the regulator building.

The actual spend by quarter for Camden as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Camden project to its URB for approval. This updated estimate saw the overall estimate decrease by $7.5 million ($5.8 million in the base estimate and $1.7 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $3.6 million – changes in site plan due to required site remediation resulted in approximately 70% more pipe and conduit. There was a limited portion of the site that was remediated prior to the start of the project, while the project had a requirement to avoid the non-remediated areas, which resulted in the layout of the buildings not being optimized to minimize the pipe routing.
- $3.3 million – due to the new compressor sizing requiring additional load, the existing 5kV transformers were not adequate and required replacement of equipment, associated switchgear, and an additional 30x42 foot raised platform to house the equipment.
- $2.9 million – additional schedule coordination needed to meet site remediation deadline requirements required additional resources.
- $1.7 million – building size increase based on final piping design; additional steel and prices higher than estimated.
- $0.8 million – higher than estimated mobilization/demobilization costs based on actual bids; asbestos abatement of M&R building and onsite security.
- $0.6 million – updated R&C based on current risk register.
- ($18.1 million) – removal of LPA components from ES 2 project scope (includes valves, piping, buildings, construction costs, engineering, testing and commissioning).
- ($2.3 million) – adjustment to R&C to remove risk items associated with LPA scope.

As much of this updated estimate involves impacts associated with the LPA scope, PSE&G also presented an estimate to its URB that documented the changes from the $15.4 million Office level estimate to the current $21.8 million Conceptual estimate to present a summarized view of the changes to the current ES 2 project scope (i.e. no LPA scope adjustments, addition or removal). The cost drivers from the earlier Office level estimate to the current Conceptual estimate were:

- $2.9 million – changes in site plan due to required site remediation that impacted the building location relative to inlet/outlet piping and resulted in additional piping and conduit required.

- $2.4 million – additional schedule coordination needed to meet site remediation deadline requirements (added resources, premium time).
- $1.8 million – building size increased based on final piping design; additional steel required and prices higher than estimated.
- $1.4 million – other construction: Higher mobilization/demobilization costs based on actual contractor bids; Asbestos abatement of M&R building.
- ($2.1 million) – drawdown of R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$13,326	$859,350	$2,147,696	$2,791,701	$7,655,276	$1,862,886	$2,978,844	$191,919

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$13,467,350	$21,800,000	$18,500,999	73%

2. Central

During the second quarter of 2022, $7,029,778 was spent on the Central project compared to a forecast of approximately $7.4 million, which brought the total spend to approximately $19.0 million. The forecasted in-service date for the Central project as of the end of the second quarter of 2022 remains at November 30, 2023, unchanged from the status as of the end of the first quarter of 2022.

Notable activities on the Central project during the second quarter of 2022 included:

- Excavated footings and foundations for regulator and heat exchanger/flow control buildings;
- Started forming and pouring foundations;
- Pipe fabrication;
- Steel erection for regulator, heater, and control buildings;
- Started installation of meter runs in regulator building;
- Set SCADA building in place.

The actual spend by quarter for Central as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Central project to its URB for approval. This updated estimate saw the overall estimate increase by $7.9 million ($7.5 million in the base estimate and $0.4 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $6.6 million – design evolution of building configuration/foundations caused modifications to: inlet/outlet header configurations, overpressure protection, piping, electrical, conduits, and refinement of material/equipment specifications.
- $3.0 million – based on final IFC piping design and building layout, LPA injection points required relocation needing additional valves, material, foundations, demolition, and pipe supports.
- $1.8 million – Transco scrubber: final design flow exceeds existing scrubber capacity, requiring a new and larger scrubber with additional piping, valves, and foundation.
- $1.6 million – station by-pass: relocated away from proposed regulation building to allow access in case of station emergency.

- $0.5 million – shift in-service date: additional mobilization and demobilization of the construction contractor and associated carrying costs to shift in-service from 2022 to 2023.
- $2.4 million – updated R&C.
- ($5.0 million) – removal of LPA components from ES 2 project scope (includes valves, piping, buildings, construction costs, engineering, and testing and commissioning).
- ($1.0 million) – adjustment to R&C to remove risk items associated with LPA scope.
- ($1.0 million) – removal of scrubber components from ES 2 project scope (includes scrubber equipment, valves, piping, construction costs, and engineering).
- ($0.2 million) – adjustment to R&C to remove risk items associated with scrubber scope.
- ($0.8 million) – updated R&C based on current risk register.

As much of this updated estimate involves impacts associated with the LPA scope, PSE&G also presented an estimate to its URB that documented the changes from the $19.7 million Office level estimate to the current $36.9 million Conceptual estimate to present a summarized view of the changes to the current ES 2 project scope (i.e. no LPA scope adjustments, addition or removal). The cost drivers from the earlier Office level estimate to the current Conceptual estimate were:

- $6.9 million – construction: based on actual bids & PO for construction costs; includes additional pipe supports, foundations, gas main tie-ins, pipe prefabrications, additional electrical and instrumentation, and current market conditions.
- $5.4 million – building/foundation & mechanical: driven by design evolution of the building configuration/foundations; increasing the building count from two to four buildings and increasing the number of heater replacements from one to five. This design evolution led to modifications to: inlet/outlet header configurations, additional foundations; overpressure protection, piping, electrical, instrumentation, conduits, and refinement of material/equipment specifications.
- $3.0 million – procurement: driven by procurement of two additional buildings and four heaters required for final design and increases due to market conditions.
- $1.6 million – station by-pass: relocated away from the proposed regulation building to allow access in case of station emergency.
- $1.2 million – project management, licensing & permitting, and engineering: increase due to actual spend to date and estimate to complete.
- $0.5 million – shift in-service date: additional mobilization and demobilization of the construction contractor and associated carrying costs to shift in-service from 2022 to 2023.
- ($1.4 million) – update of R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$6,869	$670,582	$4,226,277	$7,112,617	$7,029,778	$3,671,463	$1,479,499	$7,203,120

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$19,046,122	$36,900,000	$31,400,204	61%

3. East Rutherford

During the second quarter of 2022, $4,413,835 was spent on the East Rutherford project compared to a forecast of approximately $4.8 million, which brought the total spend to approximately $8.3 million. The

forecasted in-service date for the East Rutherford project as of the end of the second quarter of 2022 remains unchanged from the status as of the end of the prior quarter at December 16, 2022.

Notable activities on the East Rutherford project during the second quarter of 2022 included:

- Set up frac tank for ground water management;
- Excavated for temporary bypass lines and installed hot taps for temporary bypass;
- Completed hazardous abatement in regulator building;
- Initiated station outage;
- Completed demolition of regulator building and removal of all existing yard pipe;
- Prepared for pile driving;
- Continued pipe fabrication;
- Installed water filtering equipment.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the East Rutherford project to its URB for approval. This updated estimate saw the overall estimate increase by $9.5 million ($7.9 million in the base estimate and $1.6 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $3.3 million – outage constraint: construction contractor sequencing and durations were longer than anticipated and required additional resources; construction limited by winter heating season.
- $1.6 million – design evolution: changed from one large heater to two smaller heaters to facilitate maintenance of heater tubes; increased piping wall thickness to mitigate high noise levels; upgraded temporary regulator skids to allow additional operational controls during construction.
- $0.5 million – design required upgrade to electrical service from 200a/120vac to 400a/480vac to support additional equipment and includes the separation of the currently shared Transco/PSE&G electrical service to the station. This requirement stemmed from the Interconnection Agreement between Transco and PSE&G that called for PSE&G to provide power to Transco and by utilizing a separate service disconnect, it ensures that an electrical shutdown by either Transco or PSE&G will not impact the other party, improving the safety and reliability of the station as a result.
- $2.0 million – building footprint: increased costs associated with regulator and control buildings, including materials, building erection, piles, foundations, and fit out of instrumentation and controls.
- $0.5 million – environmental: based on samples taken during detail design, the building/piping will require lead/asbestos/PCB abatement; higher than anticipated water table requires additional dewatering.
- $1.6 million – updated R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$9,010	$521,865	$1,783,623	$1,551,290	$4,413,835	$9,523,474	$3,194,450	$702,502

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,279,623	$26,000,000	$21,700,048	38%

4. Mount Laurel

During the second quarter of 2022, $42,260 was spent on the Mount Laurel project compared to a forecast of approximately $58,000, which brought the total spend to approximately $1.1 million. The forecasted in-service date for the Mount Laurel project as of the end of the second quarter of 2022 remained unchanged from the status as of the end of the prior quarter at November 30, 2023.

Notable activities on the Mount Laurel project during the second quarter of 2022 included PSE&G receiving updated pricing from construction contractors and PSE&G receiving the interconnection agreement from Transco.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted the Conceptual estimate for the Mount Laurel project to its URB for approval. This updated estimate saw the overall estimate increase by $4.4 million ($3.3 million in the base estimate and $1.1 million in R&C) from the previously approved Study level estimate, with the changes driven by:

- $1.9 million – construction bid: direct impacts to construction contractor based on current market conditions since original estimate.
- $0.7 million – material price increase: increase in material costs and shipping based on current quotes received.
- $0.7 million – project management/oversight: additional project management, oversight, and carrying costs to shift in-service from 2022 to 2023.
- $1.1 million – updated R&C based on current risk register.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$5,965	$362,167	$527,341	$135,639	$42,260	$77,419	$118,261	$11,430,951

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,073,372	$15,800,000	$12,700,000	8%

5. Paramus

During the second quarter of 2022, $115,998 was spent on the Paramus project compared to a forecast of approximately $150,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the Paramus project as of the end of the second quarter of 2022 remains unchanged from the forecast as of the end of the prior quarter at December 29, 2023.

Notable activities on the Paramus project during the second quarter of 2022 included:

- Engineer developed and submitted 70% drawings for review; and,
- RFP issued for major equipment items.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. During the second quarter of 2022, PSE&G submitted an updated Study level estimate for the Paramus project to its URB for approval. This updated estimate saw the overall estimate increase by $6.2 million (entirely within R&C, no increase to

the base estimate) from the previously approved Study level estimate, with the changes driven by the current risk register and the experience of other more advanced projects in the ES 2 Program.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals					*Forecast*		
$8,842	$462,452	$568,344	$94,755	$115,998	$120,754	$726,505	$9,402,362

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$1,250,390	$19,900,000	$11,500,011	11%

6. Westampton

During the second quarter of 2022, $132,517 was spent on the Westampton project compared to a forecast of approximately $191,000, which brought the total spend to approximately $8.3 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that continued to be performed in 2022.

During the second quarter of 2022, notable activities on the Westampton project included:

- Completed installation of cathodic protection components; and,
- Continuing to work through punch list items.

The remaining items to closeout the project include corrosion protection work and final punch list items relating to site paving/grading. PSE&G expects these activities to be fully complete around July.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. A revised Definitive estimate was submitted by PSE&G and approved by its URB in the second quarter of 2022. As the project was essentially complete at this time, the updated estimate removed the remaining R&C ($900K) and reduced the base estimate to reflect the actual costs (reducing the base estimate by $700K).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals					*Forecast*		
$8,395	$1,032,670	$6,961,216	$178,124	$132,517	$123,562	$35,903	$-

Actuals to Date	Estimate	Current Forecast	% of Actuals to Forecast
$8,312,921	$8,400,000	$8,472,386	98%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 SECOND QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

JUNE 28, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 Second Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q1 2022 Report, S-INF-3** Regarding the State Street Substation project, the IM's Q1 2022 Report state that the initially planned overhead route was no longer feasible due to an existing overhead pole in the area that was not known at the time of the initial design, and the updated route requires the installation of an underground manhole and duct bank system. a. Please estimate the cost increases associated with this scope change. b. Please provide additional details explaining how the existing overhead pole caused the initially planned overhead route to become infeasible. c. Please indicate if the Company considered other overhead alternatives before opting for an underground route. d. Please explain why the existing overhead pole was not identified during field inspections.	Regarding the State Street project: a. PSE&G estimates the costs associated with the overhead route design change is approximately $370,000, with a total cost of approximately $870,000 for this circuit 4005/tie feeder. b. The initial planned route for the circuit 4005/tie feeder was based on an Office level overhead design/scope that was not confirmed in the field at the time. During field inspections in the detailed design phase, it was discovered that an existing pole line already occupied the intended route along Cooper Street. c. Three overhead routers were evaluated by PSE&G (Cooper Street, Federal/Market, and Right-of-way to Route 30). d. The existing overhead pole was identified during field inspections that occurred in the detailed design phase.	No change
S-INF-2	**Reference Q2 2022 Report, Page 4, Cost-Effectiveness and Efficiency of Investments** Please discuss the cost-effectiveness of the Contingency Reconfiguration subprogram given that the total anticipated number of recloser and fuse saver installations has decreased significantly from originally budgeted totals.	The initial scope and estimate to the actual installed scope and final costs can serve as a baseline in evaluating the cost-effectiveness and efficiency of executing the work, but consideration also must be given to the underlying drivers and reasons for any changes in scope or cost. Each month PSE&G reviews the actual cost per unit and hours per unit on the installations and assesses any variances from its estimate and assumptions to inform the forecast at completion. Below the IM discusses the primary changes from the initial scope and estimate to final installed units and costs for the Fuse Savers and reclosers, respectively. Fuse Savers In the ES 2 filing, PSE&G identified 3,282 circuits where customers are served from overhead facilities on a branch line as candidates to receive reclosing devices (Fuse Savers). At the time of the ES 2 filing, PSE&G	No change

ID #	Question/Comment	IM Response	Report Changes
		estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed; therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices."* The construction standard and training was developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average $35,216 and two-phase devices average $48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by: • The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately $10,000 in costs); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole. <u>Reclosers</u> In the ES 2 filing, PSE&G identified 1,190 circuits as candidates for recloser investments, comprised of 690 13kV circuits and 500 4kV circuits.	

ID #	Question/Comment	IM Response	Report Changes
		PSE&G's approach to this scope was to update the circuit list on a recurring basis through the execution of the Program to reflect changes to the system (either work already completed or work planned in the near-term). This effort included conducting detailed reviews of the system to identify cost effective opportunities to include other circuits in the Program following the same cost/benefit process utilized in the ES 2 filing. Ultimately, PSE&G installed a total of 1,467 reclosers through the ES 2 Program, which included 954 13kV circuits and 513 4kV circuits, representing an increase of 277 units from what was initially planned.	
S-INF-3	**Reference Q2 2022 Report, Page 18** Regarding the cost reductions associated with the Lakeside Avenue project: a. Please provide additional information about the scope reduction associated with the electrical construction award, including estimated cost savings. b. Please explain why the 4kV bus scope was transferred to the 69kV transmission project and provide the estimated Energy Strong II cost savings.	Regarding the drivers to the cost forecast reduction on the Lakeside Avenue project: a. The project initially planned for elevated stair rails and rigging of the switchgear that was no longer required. This resulted in a contract price that was approximately $1.5 million lower than what was estimated with that initial scope. b. PSE&G transferred the 4kV bus scope based on its practice for delineation of the transmission/distribution systems interconnection point at the high side bushing on the transmission/distribution transformer. The sections of the 4kV bus scope (bus work and steel supports) transferred to the 69kV transmission project are tied to the high-side bushings of the three 69/4kV transformers, which is classified as a transmission asset. PSE&G estimates the costs associated with this transferred scope are approximately $300,000.	**Section III.A.6.**
S-INF-4	**Reference Q2 2022 Report, Page 18** Please provide additional information about the scope increases on the Clay Street substation project and this associated cost increases.	The detail of this cost forecast increase has been added to the discussion on the Clay Street project within **Section III.A.2.**	**Section III.A.2.**
S-INF-5	**Reference Q2 2022 Report, Page 28, Contingency Reconfiguration Subprogram** Regarding the Fuse Saver projects: a. What is attributed to the scope being reduced from 1,713 units (See Q1 2022 Report, S-INF-5) to 1,641 units? b. Of the 1,641 total forecasted units, how many are expected to require an external antenna to address communication issues?	Regarding the Fuse Saver scope of work: a. PSE&G's approach on forecasting the number of Fuse Savers to be installed during the Program continues to follow a quarterly review of the actual cost data and related installation status information to update the installation plan and overall quantity of units planned for the Program to align with the established budget for this scope of work. b. Based on the units installed to date, PSE&G estimates that approximately 10% of the locations will require the modified external antenna.	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
	c. Please explain why the delay in Fuse Saver installations associated with the Company's D-SCADA freeze could not be reasonably foreseen during the scheduling process. Please also indicate if additional D-SCADA freezes are expected to occur within the remainder of Energy Strong II.	c. The D-SCADA freeze was identified ahead of its implementation, however it still resulted in an approximate two-week period in which installations were unavailable. The other major factor that influenced Fuse Saver installations during the second quarter of 2022 was the technical issues encountered on two of the first devices installed following the earlier pilot program (*see also* RCR-IM-15). There are no ES 2 related D-SCADA production system freezes planned or contemplated for the remainder of the Program.	
S-INF-6	**Reference Q2 2022 Report, Page 29, Grid Modernization – Communication System Subprogram** Regarding the Retrofit Substation Remote Terminal Unit (RTU) scope: a. Please identify the projects removed from the program and explain how PSE&G determined that the projects are no longer necessary. b. Please discuss PSE&G's rationale to include not only substations served by Verizon plain old telephone service (POTS) (which represented 196 substations), but also those served by Verizon 4G service (which represented 22 additional stations). (See Q1 2022 Report, S-INF-6).	Regarding the Retrofit Substation RTU scope: a. No stations have been removed from the Retrofit Substation RTU scope. b. The intent of PSE&G was to replace the RTUs relying on third-party communication, which included both the Verizon POTS and Verizon 4G service. Previously, PSE&G removed the substations served by the Verizon 4G service from the subprogram following an initial assumption that only the RTUs served by Verizon POTS would be replaced that was later clarified to include all third-party services.	No change
S-INF-7	**Reference Q2 2022 Report, Page 30, Grid Modernization – Communication System Subprogram** Regarding the identified challenges and lessons learned for the Grid Modernization – Communication System subprogram, please discuss if these issues (including inadequate site investigations and lack of comprehensive review and updating location requirements, grouping, and prioritizing locations for new fiber installation) specifically contributed to any cost increases that would not have otherwise occurred absent these issues.	Given the variety of factors that influenced the execution of the fiber projects within the Grid Modernization – Communication System subprogram (including executing through the Covid-19 pandemic), it would be difficult to parse out specific cost impacts stemming from specific issues encountered in the execution of the fiber projects. For example, one of the issues identified by PSE&G was inadequate site investigations that resulted in required items being left out of the initial scope definitions. This led to cost increases as the missing scope items were identified and included in the projects, but they were nonetheless requirements for the project to achieve its intended objectives. From the IM's perspective, there are elements of these issues/lessons learned that potentially caused cost inefficiencies, such as the lack of a comprehensive review to update location requirements and group projects for potential efficiencies. However, other issues encountered were more related to typical project execution risks, such as the increased time to	No change

ID #	Question/Comment	IM Response	Report Changes
		obtain railroad permits and lead time for scheduling commissioning resources, and with this scope of work having a fixed budget with no R&C, any realized risks inherently led to cost increases.	
S-INF-8	**Reference Q2 2022 Report, Pages 32-33, Tables 19 and 20** Please clarify if the spending for "Retrofit reclosers" also includes spending for retrofitting RTUs. If not, please explain the significant amount of forecasted spending, given that retrofitting of reclosers was completed in Q4 2021.	The Grid Modernization – Communication System subprogram is responsible for the procurement, handling, delivery and oversight of the Fuse Saver radios being installed within the Contingency Reconfiguration subprogram. The current spend for the Retrofit reclosers scope relates to materials (radios and kitting) and associated project management costs for the Fuse Saver scope. The specific costs related to the Substation RTU scope have been split out in **Table 19** and **Table 20**.	**Table 19 & Table 20**
S-INF-9	**Reference Q2 2022 Report, Page 34, Grid Modernization – Communication System Subprogram** Regarding the Grid Modernization – Communication System subprogram, please provide additional details about the fiber scope changes which contributed to a cost increase of $3 million.	The details of the transition of the fiber installation and cutovers scope from the Office level estimate to Study level estimate to the current Definitive level estimate are shown on **Table 16**. In summary, the drivers of the current $3.0 million estimate increase are: • OP estimates: $2.5 million – actual costs higher than estimated. • IP estimates: $2.2 million – refinement of Office level estimates. • Changed routes: $0.9 million – routes for Montclair (+$1.3 million) and Bloomfield (-$0.4 million) projects changed to provide simplified designs and avoid extensive inspections and permitting associated with the original OP routes. • Fiber cutovers: $0.3 million – increase due to scope and estimate refinement. • Scope reduction: ($2.9 million) – removal of selected projects from the subprogram. The specific scope refinement related to changes made to meet updated system communication requirements.	No change
S-INF-10	**Reference Q2 2022 Report, Page 35, Grid Modernization – ADMS Subprogram** Regarding the ADMS project, it is noted that the scope of work includes the replacement of existing D-SCADA elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra). Please discuss if any equipment deployed within the Company's system will become obsolete as a result of the ADMS implementation.	The infrastructure for Common Gate Interface (CGI) – Outage Management System (OMS) will be obsolete and retired after OSI OMS go live. The associated CAD infrastructure will also be obsolete after DWMS CAD for electric and gas operations is completely replaced by MWMS, which is expected by mid-2024. For the Platform, DSCADA-Legacy hardware was decommissioned as part of the hardware upgrade involved with the Platform scope and implementation.	No change

ID #	Question/Comment	IM Response	Report Changes
S-INF-11	**Reference Q2 2022 Report, Page 37, Grid Modernization – ADMS Subprogram** Regarding the identified challenges and lessons learned for the Grid Modernization – ADMS subprogram: a. Please discuss if these issues (including lack of project organization with understanding future projects within portfolio/strategy and deficiency of proper resources) specifically contributed to any cost increases that would not otherwise have occurred absent these issues. b. Please discuss if these issues are expected to have any implications on the functionality of the ADMS.	The issues identified and encountered with the execution of the Grid Modernization – ADMS subprogram generally relate to the first-of-a-kind nature of this scope of work, the limited project definition at the time of the ES 2 filing, and the decision to incorporate lessons learned from Topical Storm Isaias shortly after operational planning for the project had completed. **Table 21** summarizes the evolution of the Grid Modernization – ADMS subprogram estimate from the initial $35.0 Office level estimate through the $42.7 million Conceptual level estimate to the current $56.3 million Definitive level estimate. In further examining these cost drivers, the IM has grouped them into the following primary categories: • Scope changes/design evolution: $10.5 million; • Project execution/resources: $4.5 million; • Schedule impacts: $3.5 million; and, • R&C: $2.8 million. Concerning the identified challenges and lessons learned and if those specifically contributed to any cost increases that otherwise would not have occurred, it is the IM's view that the majority of these costs would likely have been incurred for delivery of the final scope of work (considering the scope evolution, including lessons learned from Tropical Storm Isaias, that also drove changes to the schedule and resource requirements). Importantly, these issues will not have impacts on the functionality of the ADMS, which will also benefit from the updated scope and lessons learned incorporated from Tropical storm Isaias).	
S-INF-12	**Reference Q2 2022 Report, Page 38, Electric Stipulated Base** Regarding the Outside Plant-Higher Design Standards (OP-HDS) projects within Electric Stipulated Base: a. It is indicated that circuits will be selected based upon Value of Lost Load (VOLL). Please discuss if the circuits' reliability metrics will also be considered. b. Please provide the estimated costs of the currently contemplated OP-HDS scope.	Regarding the OP-HDS scope: a. The VOLL metric combines the customer minutes interrupted reliability metrics with the economic cost impact on the affected customers to estimate the value to customers of improved circuit performance. b. While PSE&G is preparing and advancing the OP-HDS work, at this time it has incurred no costs within the ES 2 Program. While PSE&G intends to use any remaining funds from the Life Cycle projects towards the OP-HDS scope of work, in early 2023 PSE&G also transferred some of this work to its Infrastructure Advancement Program that has a similar scope.	No change

ID #	Question/Comment	IM Response	Report Changes
S-INF-13	**Reference Q2 2022 Report, Page 42, State Street (Outside Plant)** Please provide additional details about the "delays in reaching an agreement with the County on restoration efforts", including any additional costs resulting from the eventual agreement.	Camden County requested PSE&G use concrete and doweling for temporary patching in the roadways after the test pits on the State Street OP project were completed. PSE&G met with the County to advise them that the manhole and duct bank installation would closely follow completion of the test pits and that would make the temporary patching requested by the County to go beyond typical restoration efforts considering the project would be excavating in the same locations in the near future. After further negotiations with the County, an agreement was reached to forego the use of concrete for the temporary patching (with the provision that if there is a failure, any repair would utilizing concrete). PSE&G expects no additional costs associated with this effort, but the delay in reaching a resolution on this did affect the project schedule.	**Section III.E.5.**
S-INF-14	**Reference Q2 2022 Report, Page 43, Gas M&R Station Upgrades** Regarding the Gas M&R Station Upgrades, please indicate if all six (6) projects will incorporate a change in heater technology from water bath to more efficient glycol heaters. Please also discuss any cost increases associated with this scope change.	PSE&G implemented a change in heater technology at the Camden, Central, and Paramus stations. This change from water bath to more efficient glycol heaters was only made at facilities where all of the heaters warranted life cycle replacement, as such this was not considered a scope change.	No change
S-INF-15	**Reference Q2 2022 Report, Page 43, Gas M&R Station Upgrades** Regarding the cost increases for the Gas M&R Station Upgrade projects from the Office level estimates: a. Please discuss if the identified issues and lessons learned (including insufficient investigations in the development of the projects during front-end planning, lack of formal scope lockdown, lack of comparative estimates, and a lesser experienced project team) specifically contributed to any cost increases that would not have otherwise occurred absent these issues. b. Please indicate if PSE&G incorporated these lessons learned before proceeding with the Gas M&R station upgrades approved in PSE&G's Infrastructure Advancement Program (approved June 29, 2022 in Docket Nos. EO21111211 and GO21111212).	The challenges encountered and the resulting lessons learned resulted in cost increases to the Gas M&R projects that largely would have been required to complete the objectives of improving the reliability, safety, and environmental performance of the stations as they generally related to lack of scope definition and related upfront planning and are less tied to the actual execution of the projects. For example, on the Central M&R project that went from an Office level estimate of $15.4 million to a Conceptual level estimate of $36.9 million, the cost increase detailed in **Section III.F.2.** can be primarily attributed to the complexity of the station that has three pipeline companies feeding the station (essentially creating three mini-stations on one site) that required extensive coordination for construction, outages, and testing and commissioning, including the use of a station by-pass. In addition, the end-of-life condition of the station's heaters resulted in the need for two additional buildings and four additional heaters from the initial scope. On top of that, the general market conditions during and after the Covid-19 pandemic have led to higher than expected cost increases for labor, equipment, and material. The lessons learned identified by PSE&G largely focus on enhancing the project origination and estimating processes, including performing a review if the settlement	No change

ID #	Question/Comment	IM Response	Report Changes
		value is materially different than what was initially filed. For the ES 2 Program, PSE&G's estimate for the six projects ultimately approved for the Program was $119.3 million, however, the Stipulation budget was established at $101.0 million (combined accelerated and stipulated base funding). As a result, the original R&C amounts were reduced along with an arbitrary cut to align with the Stipulation budget. PSE&G has informed the IM that the identified lessons learned have been incorporated into the Company's planning and execution of the Gas M&R projects within the Infrastructure Advancement Program.	
S-INF-16	**Reference Q2 2022 Report, Page 46, Camden M&R Station** Regarding the cost increase of $3.6 million on the Camden M&R Station project associated with site plan changes: a. Please provide additional details explaining how the required site remediation resulted in approximately 70% more pipe and conduit being necessary. b. Please provide additional details about the required site remediation, including how this relates to the Camden M&R Station project.	Regarding the $3.6 million cost increase on the Camden M&R project associated with site plan changes: a. This was due to the limited area of the site that was remediated prior to the project and the need for the project to avoid the non-remediated areas, which resulted in the layout of the buildings not being optimized to minimize the pipe routing. b. The portion of the site where the M&R station is being built has already been remediated. The remainder of the site will remediated after completion of the Camden M&R project.	**Section III.F.1.**
S-INF-17	**Reference Q2 2022 Report, Page 46, Camden M&R Station** Regarding the cost increase of $3.3 million on the Camden M&R Station project associated with the new compressor sizing, please compare the new compressor sizing to that of the prior compressor and rationalize the need for a higher capability compressor.	The referenced $3.3 million increase associated with the compressor were removed from the ES 2 project scope as part of PSE&G removing the LPA scope from the Gas M&R projects (referenced by the $18.1 million reduction noted in the estimate discussion). With this scope adjustment, PSE&G also presented an updated estimate to its URB that has been added to this discussion on the Camden M&R project estimate.	**Section III.F.1.**
S-INF-18	**Reference Q2 2022 Report, Page 47, Central M&R Station** Regarding the cost increase of $3.0 million on the Central M&R Station project associated with the relocation of Liquid Propane Air (LPA) injection points, please clarify if these costs were removed from Energy Strong II similarly to the other LPA components.	The estimated $3.0 million increase associated with the relocation of the LPA injection points was removed from the ES 2 project similar to the other LPA components.	**Section III.F.2.**
S-INF-19	**Reference Q2 2022 Report, Page 47, Central M&R Station**	Regarding the noted $1.0 million cost decrease on the Central M&R project estimate associated with removal of the scrubber components from the ES 2 project scope:	No change

ID #	Question/Comment	IM Response	Report Changes
	Regarding the cost decrease of $1.0 million on the Central M&R Station project due to the removal of scrubber components from Energy Strong II project scope: a. Please explain the Company's rationale for removing the scrubber components from the program. b. Please indicate if the scrubber components will also be removed from the program for the other M&R Station projects. c. Please clarify if the cost increase of $1.8 million associated with the Transco scrubber will also be removed from the program.	a. PSE&G removed the scrubber components from the ES 2 project scope as the replacement of the scrubber was not identified in the filing documents. b. The scrubber components will not be removed from the other ES 2 Gas M&R projects as they were listed components in the filing documents for those projects. c. PSE&G has removed costs associated with the Transco scrubber components from the ES 2 Program.	
S-INF-20	**Reference Q2 2022 Report, Page 48, East Rutherford M&R Station** Regarding the cost increase of $0.5 million on the East Rutherford M&R Station project associated with the electrical service upgrade, please explain the need to separate the shared Transco/PSE&G electrical service.	The Interconnection Agreement between Transco and PSE&G specifically requires PSE&G to provide power to Transco. By providing Transco with a separate service disconnect, it ensures that an electrical shutdown by either Transco or PSE&G will not impact service to the other and improves the safety and reliability of the station as a result.	**Section III.F.3.**
RCR-IM-1	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please provide an update to the Leonia switchgear delivery delay.	The Leonia 13kV switchgear #2 was delivered on June 16, 2022 (as shown in **Table 10**).	**Section I.**
RCR-IM-2	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please identify the "certain individual subprograms … forecasted near or above their Stipulation budgets."	The current subprogram forecasts and ES 2 Program budgets are shown in **Table 1**, which indicates the Grid Modernization – Communication System, Grid Modernization – ADMS, Gas M&R, and Contingency Reconfiguration subprograms have current forecasts above the Program budget. Overall, the total ES 2 Program forecast of approximately $826.9 million represents 98% of the $842 million Program budget (including the accelerated recovery and stipulated base funding mechanisms).	**Section I.**
RCR-IM-3	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please identify the "other projects with forecasted in-service dates near the Program end date that are at risk due to the delays on the switchgear deliveries[.]"	The Electric Station Flood Mitigation subprogram projects with forecasted in-service dates near the end of the Program end date of December 2023 and with open switchgear deliveries as of the end of the second quarter of 2022 included (with the current in-service forecast indicated in parentheses): Front Street (11/8/2023); Lakeside Avenue (9/18/2023); Orange Valley (12/29/2023); Waverly (2/27/2024); and Woodlynne (10/10/2023).	**Section I.**
RCR-IM-4	With reference to page 3 of the Independent Monitor's Draft Second Quarter 2022 Report, please indicate whether other	The forecasted in-service date for the Waverly substation project was originally planned for the fourth quarter of 2023, but after the initial site	**Section I.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td>supply chain issues in addition to the 4 kV switchgear delivery delays are contributing to the February 27, 2024 forecasted in-service date for the Waverly substation.</td><td>plan was rejected in March 2021, this shifted the entire project out by approximately one year to the end of 2024 (based on the timeline around resubmitting the site plan). In September 2021, the revised site plan was submitted to the Newark Planning Board and approved in December 2021. With the revised site plan approved earlier than planned, it advanced the forecasted in-service date to September 2024 by shifting the construction activities forward as supported by the improved permit dates. During the first quarter of 2022, the project team continued to detail and analyze the construction schedule for opportunities, which led to the in-service date to improve to March 2024. During the second quarter of 2022, progress advanced largely on or ahead of schedule, which contributed to the in-service date advancing seven days to February 27, 2024.

The Waverly project also has multiple in-service dates, from the 26kV switchgear (forecasted for September 2022), the 4kV switchgear, T1, and T2 (forecasted for October 2023), and the T3 (forecasted for February 2024). While the 4kV switchgear delivery accounted for the 11 day slip to the forecasted in-service date from the first to second quarter of 2022, the primary driver to the current in-service date for Waverly was the impact from requiring a revised site plan as detailed above.</td><td></td></tr>
<tr><td>RCR-IM-5</td><td>With reference to page 4 of the Independent Monitor’s Draft Second Quarter 2022 Report, please confirm that only 13 fuse saver units were installed during the 2022 Second Quarter, leaving 1,515 units to be installed by December 31, 2023 as part of the Contingency Reconfiguration subprogram.</td><td>This status of the Fuse Savers as of the end of the second quarter of 2022 is confirmed, with 13 devices installed during the second quarter for a total of 126 devices installed during the Program out of a forecast of 1,516 devices.</td><td>No change</td></tr>
<tr><td>RCR-IM-6</td><td>With reference to Figure 2 – ES 2 CWIP Balances by Subprogram as of June 30, 2022, please explain the discrepancy between the $69.3 million Q2 2022 subtotal for Electric Station Flood Mitigation, while a preceding paragraph on page 8 notes a CWIP Electric Station Flood Mitigation costs for “Hasbrouck ($12.4 million), State Street ($11.1 million), Clay Street ($11.0 million), and Waverly ($9.7 million)” of $44.2 million in total for the same subprogram.</td><td>The referenced text concerning the CWIP balances for the Electric Station Flood Mitigation subprogram highlights the individual projects with the highest CWIP balances, but does not detail every project within the subprogram. The CWIP balances as of the end of the second quarter of 2022 for each substation projects is provided as follows:

<table><tr><th>Project</th><th>Q2 2022 CWIP Balance</th></tr><tr><td>Academy Street</td><td>$-</td></tr><tr><td>Clay Street</td><td>$11,047,959</td></tr><tr><td>Front Street</td><td>$3,796,963</td></tr><tr><td>Hasbrouck Heights</td><td>$12,352,213</td></tr></table></td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
		Kingsland $1,754,738 Lakeside Avenue $1,860,702 Leonia $4,668,986 Market Street $149,782 Meadow Road $1,777,667 Orange Valley $1,268,318 Ridgefield 13kV $2,284,652 Ridgefield 4kV $- State Street $11,081,551 Toney's Brook $2,452,994 Waverly $9,641,079 Woodlynne $5,220,160 **Total** **$69,357,695**	
RCR-IM-7	With reference to Table 9 – ES 2 Electric Substation Flood Mitigation Upcoming Activities for Q3 2022, please explain the inclusion of the switchgear assembly at Hasbrouck Heights when there was no mention of this activity in the Draft First Quarter 2022 Report, Table 11 – ES 2 Electric Station Flood Mitigation Upcoming Activities for Q2 2022 on page 15, for this substation.	In the IM 2022 First Quarter Report, the upcoming activities on the Hasbrouck Heights project planned for the second quarter of 2022 were identified as the start of civil foundations and the start of electrical construction. The electrical construction activities at the end of the second quarter of 2022 primarily involved the switchgear assembly, which is why this activity was highlighted in **Table 9**.	No change
RCR-IM-8	With reference to page 15 of the Independent Monitor's Draft Second Quarter 2022 Report, concerning communications provided by PSE&G's switchgear vendor, Powercon, please explain the "more detailed and frequent status updates from Powercon" referred to in the Draft Second Quarter 2022 Report regarding remaining major equipment deliveries beyond "receiv[ing] weekly updates from Powercon on the current status of the deliveries and PSE&G's management" onsite visits to the vendor.	Concerning the additional information from Powercon, PSE&G requested and has received details in Powercon's production schedules and information from the sub-vendors/suppliers.	**Section III.A.**
RCR-IM-9	With reference to Table 10 – ES 2 Electric Substation Flood Mitigation Switchgear Deliveries as of June 30, 2022, please explain why the Ridgefield 13 kV cont. switchgear is	The 13kV contingency switchgear for Ridgefield 13kV shows a September 30, 2020 delivery date as this is when this switchgear was delivered to the project. This switchgear will also be the permanent switchgear for	No change

ID #	Question/Comment	IM Response	Report Changes
	shown with delivery date in bold of September 30, 2020 when it is the "Kingsland 13kV switchgear [] delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project[]" and will be removed.	Kingsland following its use as a contingency switchgear for the Ridgefield 13kV project.	
RCR-IM-10	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] electrical construction award higher than estimated; [2] equipment procurement higher than estimated; [3] scope increases; and [4] construction schedule recovery" contributing to the $2.3 million increase in the projected cost of the Clay Street Substation from $30.8 to $33.6 million.	The detail of this cost forecast increase has been added to the discussion on the Clay Street project within **Section III.A.2.**	**Section III.A.2.**
RCR-IM-11	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] civil and electrical construction awards higher than estimated and [2] an increased quantity of piles based on the final design" contributing to the $2.1 million increase in the projected cost of the Kingsland Substation from $6.4 to $8.5 million.	The detail of this cost forecast increase has been added to the discussion on the Kingsland project within **Section III.A.5.**	**Section III.A.5.**
RCR-IM-12	With reference to Table 11 – ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, on page 16 and the Findings and Observations on page 18, please specify the costs for each subcategory noted "[1] civil and electrical construction awards higher than estimated and [2] an increased quantity of piles based on the final design" contributing to the $2.1 million increase in the projected cost of the Kingsland Substation from $6.4 to $8.5 million.	The detail of this cost forecast increase has been added to the discussion on the Kingsland project within **Section III.A.5.**	**Section III.A.5.**
RCR-IM-13	With reference to page 19 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain what the other "[p]art of this impact" contributing the variance for Clay Street substation between forecasted second quarter spending of $2.7 million and actual spending of $1.9 million, including any delays in April and May 2022.	The second quarter of 2022 cost forecast to actual variance on Clay Street was driven by civil piling work shifting from a planned May-June execution to June-July due to the T3 contingency not being completed in April 2022 as initially planned and less foundation and duct bank work completed in June 2022 than was planned due to a safety standdown, which resulted in an approximate 10-day impact to the construction schedule.	**Section III.A.2.**

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-14	With reference to page 18 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain the individual project updates to the Academy Street, Clay Street, Front Street, Hasbrouck Heights, Kingsland, Orange Valley, Ridgefield 13kV, State Street, Waverly, and Woodlynne projects (with Hasbrouck Heights and State Street also advancing to the Definitive stage) that collectively resulted in a $15.0 million increase.	This description appears to reference the IM's First Quarter 2022 Report, where the updated estimates to the Electric Station Flood Mitigation projects resulted in an overall $15.0 million increase to the overall base estimate for the subprogram. Details of these estimate updates were discussed within the individual project sections under Section III.A. of this report. During the second quarter of 2022 there were no updates to the estimates for the projects within the Electric Station Flood Mitigation subprogram, though the subprogram forecast increased by $8.6 million as detailed in the Findings & Observations in **Section III.A.**.	No change
RCR-IM-15	With reference to page 27 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how many installed Fuse Savers experienced communication issues other than the two units returned to Siemens for testing, have any remote control units been replaced, and what are the costs with projected repairs or replacement.	PSE&G has encountered communication issues on approximately 10% of the installed Fuse Savers (including 10 devices of the 113 installed in the pilot program). The costs associated with the RCU modifications to address the communication issues are approximately $1,100 per unit in material and also slightly longer installation times, though the installation costs are not tracked separately for the devices with and without the modification. The devices returned to Siemens for testing in the second quarter of 2022 did not have communication issues, but instead encountered a voltage reading when in the open position that was determined to be ghost/induced voltage stemming from the device's proximity to a live conductor and not an issue with the device itself.	No change
RCR-IM-16	With reference to page 27 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how many of the 1,515 remaining to be installed Fuse Savers does PSE&G intend to install than "initially planned in the third and fourth quarters of 2022" and at what additional cost.	There is no material cost impact expected from this shift, essentially following the installations delays encountered during the second quarter of 2022 (as discussed in **Section III.B.**), PSE&G shifted the balance of the installations originally planned for the second quarter of 2022 across the installations planned for the remainder of the year. In total, during the second quarter of 2022, PSE&G commissioned 12 Fuse Savers in this period out of a target of 168.	No change
RCR-IM-17	With reference to Table 15 – Contingency Reconfiguration Forecasted Cost of June 30, 2022 and the findings and observations on page 28 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain how "each Division [is] now forecasted to complete the Fuse Savers scope by December 2023" when as of June 30, 2022 $8.1 million, 19 percent of the $43.9 million forecasted budget	The current end of 2023 forecasted completion for the Fuse Saver scope of work reflects a slight slip from the forecast as of the end of the first quarter of 2022 (as shown in **Table 13**). This slip reflects the limited installations conducted in the second quarter of 2022 due to the technical issues and D-SCADA freeze discussed in **Section III.B.**. PSE&G continues to establish quarterly installation targets with the Divisions, which are then split into monthly targets with forecasts updated bi-weekly, which supports completing this scope of work by the end of	No change

ID #	Question/Comment	IM Response	Report Changes
	for Fuse Saver installations and out of 1,641 total projected units, 125 units have been commissioned.	2023 (as of the end of the first quarter of 2023, 957 units had been commissioned).	
RCR-IM-18	With reference the findings and observations on page 28 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain what accounted for the Contingency Reconfiguration subprogram forecast increasing by $339,000, to a total of $145.6 million, above the Stipulation budget of $145.0 million.	The updated forecast for the Contingency Reconfiguration continues to reflect the actual costs and field conditions encountered to date as based on the currently projected number of units (Fuse Savers and reclosers) to be installed as part of the subprogram with PSE&G continuing to seek to optimize the number of units installed against the subprogram budget. For example, PSE&G's initial assumption was for 1,713 Fuse Savers to be installed as part of this subprogram, based on the actual costs incurred through the end of the second quarter of 2022, the planned number of Fuse Savers was reduced to 1,641 units after the costs per unit increased (due to a combination of higher labor, higher traffic control, and higher project management costs). Overall, the subprogram forecast has remained fairly constant since the third quarter of 2021, fluctuating between $145.3 million and $145.8 million in this time.	No change
RCR-IM-19	With reference to the findings and observations for Grid Modernization – Communications System on page 34 of the Independent Monitor's Draft Second Quarter 2022 Report, please explain the "inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget" that PSE&G noted affected the Grid Modernization – Communications System subprogram budget.	The initial fiber estimates reflected a scope that essentially included just the fiber installation itself, PSE&G identified through the first batch of projects completed that certain stations had other scope elements required to complete the fiber installation, such as battery rack space, redundant feeders, and/or similar items that had not been included in the initial project estimates. Similarly, execution of the work identified other site-specific issues, such as on the Edison project where blocked conduit contributed to an approximate $40,000 cost increase. Because these site-specific items were not identified earlier in the estimating process, they contributed to cost increases realized during execution of these projects. Additionally, because there was no R&C budget for the subprogram, any realized risks (such as missing scope or site conditions) contributed to direct cost increases rather than being absorbed by R&C funds. The approach of not including R&C funds for a group of smaller, repetitive type projects is not unusual, but does mean with a fixed budget that the overall number of projects delivered may be reduced as a result of any cost increases realized. The IM also agrees with PSE&G's decision to include R&C for future fiber installation efforts as the site-specific nature of this work and required interfaces (transmission, railroads, etc.) can lead to deviations from the initial budget assumptions and having R&C funding	No change

ID #	Question/Comment	IM Response	Report Changes
		ensures the initially targeted scope of the overall program is more likely to be achieved when these types of issues are encountered. *See also* **S-INF-7**.	
RCR-IM-20	With reference to Table 21 – Grid Modernization – ADMS Subprogram Estimate on page 36, please add subtotals in a separate column for OMS Scope Changes that contributed to the $21.3 million subprogram budget increase.	The subtotals for the OMS scope changes were originally listed in Table 21 next to the scope change descriptions, but for clarity Table 21 has been revised to better show these values.	**Table 21**
RCR-IM-21	With reference to Table 23 – ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022 on page 38, please explain whether the subprogram risk and contingency total if $2.3 million for Hamilton, Paramus, Plainfield, Woodbury and State Street substations represents a change in total compared the risk and contingency total (not shown) in Table 20 – ES 2 Life Cycle Station Upgrade Project Status as of March 31, 2022 in Independent Monitor's Draft First Quarter 2022 Report on page 36.	As of the end of the first quarter of 2022, the R&C balance for the Life Cycle Station Upgrade projects was $3.1 million. As of the end of the second quarter of 2022, the R&C balance was reduced to $2.3 million (with the $0.9 million of R&C allocated during the second quarter of 2022 going to Hamilton ($600K), Woodbury ($300K), and offset by a reduction in the base estimate to Plainfield (-$100K) with those funds returning to the R&C balance. The IM also notes the R&C balance was added to Table 20 in the IM's First Quarter 2022 Final Report.	**Section III.E.**
Rate Counsel 5/3/2023 Letter	Rate Counsel continues to note that the budget for Electric stipulated base has been set to $100 million for the life cycle subprogram. In the report for this quarter, Pegasus continued to provide Study level estimates for the five substations (Hamilton, Paramus, Plainfield, Woodbury, and State Street). (See Table 23, p. 38). The current Study level estimate for the subprogram increased by $800,000 to $97.7 million. Pegasus notes that "[d]uring the second quarter of 2022, PSE&G advanced the Hamilton, Plainfield, and Woodbury project estimates to the Definitive level." Much of the increase is attributed to advancement of Hamilton to the definitive stage with a $600,000 increase to $16.8 million and a revised forecast of $16.9 million. (p. 40).	The IM notes that only the State Street OP project remains at the Study level estimate, the other projects have either advanced to the Conceptual level (Paramus) or Definitive level (Hamilton, Plainfield, and Woodbury). The total subprogram estimate of $97.7 million is correct, but does not include the $2.3 million in R&C funds.	No change
Rate Counsel 5/3/2023 Letter	The current forecast for the Electric Flood mitigation program increased from $349.56 million in the First Quarter 2022 Report to $358.15 million in the Second Quarter Report. The IM notes the "forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $41.8 million in R&C). (p. 18). Rate Counsel notes the R&C subtotal of $41.8 million remains unchanged since PSE&G discontinued providing individual project risk and	PSE&G updates the project forecasts and the project risk registers on a monthly basis, but release of R&C funds is tied to the projects going through estimate transitions. During the second quarter of 2022, none of the Electric Station Flood Mitigation projects reached an estimate transition, thus no R&C funds were released during the quarter and the R&C balance remained unchanged from the status as of the end of the first quarter of 2022. To appreciate the availability of R&C funds, the variances between the project estimates and forecasts can be reviewed, as the forecasts offer a leading indicator in the periods between estimate	**Section III.A.**

ID #	Question/Comment	IM Response	Report Changes
	contingency costs as reported in the First Quarter 2022 Report, although the IM reports further delays in the completion dates with "three projects slipping" and the "overall subprogram forecast as of the end of the second quarter of 2022 increased $8.6 million (or 2.5%) to $358.2 million from the status as of the prior quarter."(p. 17) Rate Counsel is interested in learning how the risk and contingency estimate total of $41.80 million remains unchanged from the First Quarter 2022 Report when the subprogram forecast was $347.20 million.	transitions on if additional R&C funding will likely be required at the next estimate transition. Under this approach, and with the data from **Table 11**, it shows that the Electric Station Flood Mitigation subprogram has a current forecast of $358.2 million that is approximately $11.0 million above the current Base estimate for the subprogram, suggesting if the current trends hold approximately $11.0 million of R&C will be released.	
Rate Counsel 5/3/2023 Letter	In the First Quarter 2022 Report, the IM noted that PSE&G reported that the completion date for Kingsland had slipped 94 days (from June 30, 2023 to October 2, 2023), "driven by delays to the 13kV switchgear delivery on the Ridgefield 13kV project (Kingsland plans to use the contingency switchgear from the Ridgefield 13kV project)." In the Second Quarter 2022, the IM notes that switchgear delivery delays affect: • Clay Street - 4kV switchgear (delayed 76 days) • Leonia - 13kV switchgear #2 (delayed 33 days) • Ridgefield 13kV - 13kV switchgear #1(delayed 12 days) • Waverly – 4kV switchgear (delayed 12 days) As the IM notes in Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022, p. 15, of the two switchgear deliveries scheduled for the second quarter 2022, as noted in the First Quarter 2022 Report, only one switchgear delivery is reported for the second quarter 2022 in the Second Quarter 2022 Report. As the IM notes "as of the end of the second quarter of 2022, there were 10 switchgear deliveries outstanding for the subprogram[.]" Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of June 30, 2022 indicates six switchgear deliveries are scheduled in 2022 and 4 are scheduled in 2023. Rate Counsel is interested in understanding if the Company has adequate resources and planning contingencies to address the impact of further delays in equipment deliveries affecting multiple	The remaining switchgear deliveries continue to present a risk to the completion of the projects in the Electric Station Flood Mitigation and Electric Station Life Cycle subprograms, including the slip for the Clay Street switchgear that had previously been expected to be received in the second quarter of 2022. While the shifting delivery dates have added challenges to delivering the projects, PSE&G has attempted to mitigate these impacts by resequencing or advancing other work where possible and meeting with the Divisions at least monthly to review the current schedules and availability of resources. PSE&G and its Divisions schedule the Division resources based on the current equipment delivery dates and related items required to support the project schedule.	No change

ID #	Question/Comment	IM Response	Report Changes
	substations and address unforeseen situations beyond those reported in the Second Quarter 2022 Report.		
Rate Counsel 5/3/2023 Letter	In the Second Quarter 2022 Report, the IM reports that PSE&G continues to forecast work completion for six (Front Street, Kingsland, Lakeside Avenue, Meadow Road, Orange Valley and Woodlynne) of sixteen substation projects in the ES 2 Electric Station Flood Mitigation program during the third and fourth quarters of 2023, while the completion date for a seventh project (Waverly) remains outside the program end date of December 31, 2023. The IM noted that PSE&G continues to forecast that the Orange Valley substation work is scheduled for completion on December 29, 2023 and that the Waverly substation project is now scheduled for completion on February 27, 2024, an improvement of a week from the March 5, 2024 date provided in the First Quarter 2022 Report. The completion date for Front Street has slipped nearly two weeks to November 11, 2023, and the IM reports spending was 14 percent, $3.67 million of the total estimate of $25.9 million. The scheduled completion date for the Orange Valley substation is near the program end date of December 31, 2023, and the IM reports spending is $1.18 million, 8 percent of the total estimate of $14.7 million. The completion date for Lakeside Avenue is September 18, 2023, and actual spending is 5 percent, $1.75 million of the total estimate of $39.4 million. The scheduled completion date for the Waverly substation is after the program end date of December 31, 2023, and the IM reports spending is twenty-five percent, $8.94 million, of total estimate of $36.2 million. Rate Counsel is interested in understanding how PSE&G plans to manage work for six substation projects (Front Street, Kingsland, Lakeside Avenue, Meadow Road, Orange Valley and Woodlynne) in the third and fourth quarters of 2023, and if any accelerated work will impact current budgets for the delayed substation work in the ES 2 Electric Station Flood Mitigation program.	Concerning the six Electric Station Flood Mitigation project currently forecasted to go in-service during the third and fourth quarters of 2023, PSE&G continues to update the project schedules on a monthly basis to reflect the current status including the current forecasted delivery dates for projects with open switchgear deliveries and has also sought out additional information from its vendor (production schedules, sub-vendor statuses, etc.). Based on this updated information, the project teams evaluate any opportunities to improve the schedule and coordinate to ensure resources are available to meet the project needs. While having six of the 16 Electric Station Flood Mitigation projects go in-service over a two-quarter period represents a significant effort, particularly for testing and commissioning resources, PSE&G's planning and efforts to date have demonstrated this level of effort is achievable as in a six-week period at the end of 2022, PSE&G successfully placed four of the Electric Station Flood Mitigation projects in-service.	No change

ID #	Question/Comment	IM Response	Report Changes
Rate Counsel 5/3/2023 Letter	In the Second Quarter 2022 Report, the IM reports that PSE&G Outside Plant-Higher Design Standards (OP-HDS) scope "scope currently contemplates upgrades to approximately 40-50 circuit miles and replacement of approximately 700 poles." (p. 38). Prior quarterly reports have not included such detail. The IM notes that "[i]nitial selection of circuits for OP-HDS investments is based on … the highest annual [Value of Loss Load] (VOLL) from 2010-2020 over the baseline performance, while final circuit selection will reflect the VOLL rankings … driven by field conditions." The Rate Counsel is interested in understanding what specific "field conditions" PSE&G is planning on using for OP-HDS selection criteria. (p. 38).	Final circuit selection for the OP-HDS scope involves consideration of the actual field conditions where impacts from other projects may have resulted in a change to the actual field conditions on the circuit and may warrant no longer including particular circuits in the scope of work as a result. The IM also notes that in early 2023, PSE&G made the decision to transition the OP-HDS work planned for the ES 2 Program to its Infrastructure Advancement Program (under the Open Wire to Spacer project) due to limited funding available in the Electric Stipulated Base portion of the ES 2 Program.	No change
Rate Counsel 5/3/2023 Letter	The forecast for the Grid Modernization – Communication system subprogram remained relatively unchanged from the status as of the end of the first quarter of 2022, with an overall forecast increase of approximately $136,000 (or a 0.2% increase) to $66.3 million. (p. 34) Rate Counsel is interested in understanding what risk & contingency level for the Grid Modernization – Communication would PSE&G have assigned retrospectively based on lessons learned from the "inadequate site investigations that left required items out of the initial scope and no R&C within the initial budget."	Industry standards from AACE provide that there are a broad range of methodologies for estimating contingency amounts. The factors considered include, but are not limited to, the following: • Portfolio, program, or project type: scope, size, complexity, level of technology. • Risk type: strategic versus tactical, systemic versus project-specific. • Project phase: estimate confidence level. • Base estimate methodology: methods, tools, and data used to develop the base estimate. • Skills and knowledge: of the involved participants, both in preparing the estimate and in executing the work. The approach of not including R&C funds for a group of smaller, repetitive type projects is not unusual, but does mean with a fixed budget that the overall number of projects delivered may be reduced from what was initially estimated as a result of any cost increases or risks realized. The IM also agrees with PSE&G's decision to include R&C for future fiber installation efforts as the site-specific nature of this work and required interfaces (transmission, railroads, etc.) can lead to deviations from the initial budget assumptions and having R&C funding ensures the initially targeted scope of the overall program is more likely to be achieved when these types of issues are encountered. *See also* S-INF-7 and RCR-IM-19.	No change

ENERGY STRONG 2 PROGRAM
INDEPENDENT MONITOR
2022 THIRD QUARTER DRAFT REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

CONFIDENTIAL

NOVEMBER 13, 2023

Table of Contents

I. Executive Summary 1
II. Program Status 6
A. Key Decisions 6
B. Program Management 7
C. Cost Assignments 7
D. System Performance 13
III. Project Status 14
A. Electric Station Flood Mitigation 14
B. Contingency Reconfiguration 30
C. Grid Modernization – Communication System 33
D. Grid Modernization – ADMS 36
E. Electric Stipulated Base 39
F. Gas M&R Station Upgrades 44

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Advanced Distribution Management Systems	ADMS
Allowance for Funds Used During Construction	AFUDC
Architect/Engineer	A/E
Board of Public Utilities	BPU
Construction Work In Progress	CWIP
Costs of Removal	COR
Distribution Management System	DMS
Distributed Energy Resource Management System	DERMS
Distribution Supervisory Control and Data Acquisition	DSCADA
Energy Strong 2	ES 2
Gas Metering & Regulating	Gas M&R
Generally Accepted Accounting Principles	GAAP
Geographic Information System	GIS
Human-Machine Interface	HMI
Independent Monitor	IM
Inside Plant	IP
Issued for Bid	IFB
Issued for Construction	IFC
Liquid Propane Air	LPA
New Jersey Department of Environmental Protection	NJDEP
Open Systems International Inc.	OSI
Outage Management System	OMS
Outside Plant	OP
Outside Plant-Higher Design Standards	OP-HDS
Public Service Electric & Gas	PSE&G
Purchase Order	PO
Quality Assurance System	QAS

Record of Decision ..... ROD

Remote Terminal Unit ..... RTU

Request for Information ..... RFI

Risk and Contingency ..... R&C

Supervisory Control and Data Acquisition ..... SCADA

Utility Review Board ..... URB

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Energy Strong 2 (ES 2) Program was established from a Stipulation that the involved parties agreed to in August 2019, as approved by a Board of Public Utilities (BPU) Order dated September 11, 2019, with an effective date of September 21, 2019. The Stipulation provided the ES 2 Program would be comprised of five primary subprograms: Electric Station Flood Mitigation; Contingency Reconfiguration; Grid Modernization – Communications; Grid Modernization – Advanced Distribution Management Systems (ADMS); and Gas Metering & Regulating (Gas M&R) Station Upgrades. In addition, a Stipulated Base spend was established that includes both an electric component (higher outside plant design standards and station life cycle upgrades) and a gas component (overlapping with the Gas M&R subprogram). This report contains the Independent Monitor's (IM's) findings and observations on the ES 2 Program elements and other information on the Program's status as of the third quarter of 2022.

During the third quarter of 2022, the bulk of the spend within the ES 2 Program continued to be in the largest subprogram, Electric Station Flood Mitigation, with spend in the quarter up approximately $11.8 million from the prior quarter driven by five additional projects commencing construction, which brought all projects in the subprogram past the start of construction milestone. Spend also ramped up in the Contingency Reconfiguration subprogram where the Fuse Savers scope of work had its first full quarter of implementation. Within the other subprograms, the Grid Modernization – Communication System subprogram placed two additional fiber installation projects and one fiver cutover project in-service, with all of the fiber cutover projects and 29 of the 34 fiber installation projects now completed in the ES 2 Program. The Grid Modernization – Communication System also completed the retrofit substation remote terminal unit (RTU) scope, with an additional 48 substations completed in the third quarter of 2022, for a total of 218 substation retrofits completed in the Program. The Grid Modernization – ADMS subprogram completed sprint 21 in the Distribution Management System (DMS)/Distributed Energy Resource Management System (DERMS) scope and completed the Quality Assurance System (QAS) build and configuration for the Outage Management System (OMS) scope. The Gas M&R subprogram continued to advance construction on the Camden and East Rutherford, both forecasted to be in-service by the end of 2022 and both also having updated estimates approved during the third quarter of 2022 that resulted to no overall change in the subprogram estimate. The Hamilton, Paramus, Plainfield, and Woodbury projects in the Electric Stipulated Base scope continued construction during the third quarter of 2022, while the State Street (Outside Plant) project performed test pits ahead of the manhole and conduit work. The Outside Plant-Higher Design Standards (OP-HDS) work under the Electric Stipulated Base also commenced in the third quarter, though at this time PSE&G is performing this work outside of the ES 2 Program due to the forecasts for the life cycle station upgrade projects currently consuming the entirety of the Electric Stipulated Base budget.

Major equipment (primarily switchgear) deliveries continue to be a primary risk item for the Electric Station Flood Mitigation and Electric Stipulated Base projects with open deliveries. During the third quarter of 2022, switchgear deliveries were received on the Front Street, Ridgefield 13kV, Plainfield, and Woodbury projects. This completes the deliveries for the Electric Stipulated Base projects and leaves eight remaining for the Electric Station Flood Mitigation projects.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022 below provides the spend to date on the subprograms within the ES 2 Program and Stipulated Base compared to the total forecast and forecasted completion for each.

Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022

Subprogram	2022 Q3 Spend	Total Spend to Date*	Total Forecast*	% of Actuals to Forecast	Forecasted Completion**	Stipulation Funding Amount***
Electric Station Flood Mitigation	**$29,627,767**	**$187,304,228**	**$356,924,105**	**52%**	**Apr 2024**	**$389M**
Contingency Reconfiguration	**$7,708,933**	**$117,802,488**	**$147,615,838**	**80%**	**Dec 2023**	**$145M**
Grid Modernization – Communications	**$3,391,702**	**$61,178,303**	**$66,564,461**	**92%**	**Dec 2023**	**$64.3M**
Grid Modernization – ADMS	**$3,194,435**	**$40,961,453**	**$60,907,462**	**67%**	**Jun 2023**	**$42.7M^**
Electric Stipulated Base	**$19,163,528**	**$59,072,735**	**$100,582,790**	**59%**	**Dec 2023**	**$100M**
Gas M&R Station Upgrades^^	**$24,947,158**	**$76,376,937**	**$110,272,385**	**69%**	**Dec 2023**	**$101M^^^**
Total*	**$88,033,523**	**$542,696,145**	**$842,867,041**	**64%**	**Apr 2024**	**$842M**

-Note: total figures may not fully align due to rounding. Additionally, the total forecast includes only the base cost for the Electric Station Flood Mitigation and Gas M&R subprograms as PSE&G does not include risk and contingency (R&C) in its forecasts for these projects. See **Table 11 and **Table 23** for the Electric Station Flood Mitigation and Gas M&R project estimates, respectively, with base costs and R&C shown.*

***-Final in-service date.*

****-Following the $7.7 million transfer in July 2021 from the Grid Modernization – Communications subprogram to the Grid Modernization – ADMS subprogram.*

^-PSE&G has increased the funding for the Grid Modernization – ADMS subprogram by $13.6 million over the Stipulation amount to a total of $56.3 million (including $2.8 million in R&C).

^^-Includes both the ES 2 projects and the Stipulated Base gas projects.

^^^-PSE&G has increased the funding for the Gas M&R subprogram by $27.8 million over the Stipulation amount to a total of $128.8 million (including $24.6 million in R&C). This R&C balance is currently at $19.1 million as of the end of the third quarter of 2022.

Given the prominence of the Electric Station Flood Mitigation subprogram, which represents over half of the total ES 2 Program spending (before the Stipulated Base consideration), a summary of the projects within this subprogram is provided below in **Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2022**.

Table 2 – ES 2 Electric Station Flood Mitigation Status as of September 30, 2022

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
1. Academy Street	$9,300,000	$6,519,897	70%	**10/19/2021**
2. Clay Street	$30,800,000	$13,021,870	39%	3/23/2023 (↓+52)
3. Front Street^	$25,900,000	$9,558,510	37%	1/9/2024 (↓+62)
4. Hasbrouck Heights	$19,300,000	$13,926,106	72%	11/18/2022 (↑-35)
5. Kingsland	$8,700,000	$2,219,794	26%	11/6/2023 (↓+33)
6. Lakeside Avenue	$39,400,000	$3,292,610	8%	2/28/2024 (↓+163)
7. Leonia	$24,900,000	$22,304,216	90%	11/16/2022 (↑-27)
8. Market Street	$29,100,000	$28,140,833	97%	**6/25/2021**
9. Meadow Road	$7,200,000	$2,035,052	25%	9/28/2023 (↓+6)
10. Orange Valley	$14,700,000	$2,227,908	15%	2/2/2024 (↓+35)
11. Ridgefield 13kV	$26,100,000	$25,524,755	98%	12/8/2022 (↑-5)
12. Ridgefield 4kV	$20,800,000	$20,703,808	100%	**5/16/2021**

Project	Total Estimate (rounded)	Actuals	% of Actuals to Estimate	Forecasted In-Service Date*
13. State Street	$19,600,000	$11,609,902	59%	12/16/2022 (↑-3)
14. Toney's Brook	$16,200,000	$3,034,991	19%	5/26/2023 (↓+39)
15. Waverly	$36,200,000	$17,197,448	43%	4/30/2024 (↓+63)
16. Woodlynne	$24,000,000	$5,986,596	25%	10/10/2023

-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).* ***Bold* *dates indicate the actual in-service date.*

(↑)*-Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)*-Indicates the forecasted in-service date slipped from the prior quarter.*

^- *The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

As indicated in **Table 2**, the projects that previously started construction (Academy Street, Leonia, Market Street, Ridgefield 13kV, Ridgefield 4kV, and Waverly) continue to have the highest total spend to date. Additionally, six of the stations (Clay Street, Kingsland, Meadow Road, Ridgefield 4kV, Waverly, and Woodlynne) had new estimates approved by the PSE&G's Utility Review Board (URB) in during the third quarter of 2022. Overall, the updated estimates resulted in an increase to the base estimate of $12.5 million that was offset by a release of R&C funds to result in the total subprogram estimate remaining at $389.0 million. **Table 2** also shows that all of the remaining projects aside from Woodlynne had movement in the forecasted in-service date during the third quarter of 2022, with four advancing and eight slipping. Of these twelve projects, three of the projects (Meadow Road, Ridgefield 13kV, and State Street) had forecasted in-service dates change by less than one week. The largest changes to forecasted in-service dates were on the Lakeside Avenue, Waverly, and Front Street projects that each saw slips to their respective forecasted in-service date of at least 60 days, with Lakeside and Front Street impacted by continued delays to their switchgear deliveries and Waverly impacted by manhole rework required prior to the 26kV switchgear energization and the need for Y-buses prior to the 26kV circuit cutovers that will increase the overall duration of the cutovers. As a result of these continued schedule changes, four projects now have forecasted in-service dates in early 2024 (Front Street, Lakeside Avenue, Orange Valley, and Waverly). While PSE&G continues to assess opportunities to regain the schedule on these projects, each of these projects has an open switchgear delivery that continues to present a risk to the project schedule.

The current cost forecast for the Electric Station Flood Mitigation subprogram of $356.9 million decreased approximately $1.2 million from the prior quarter and continues to be below the Stipulation budget of $389.0 million. However, schedule challenges, particularly on the projects with open switchgear deliveries and forecasted in-service dates near the Program end date will continue to warrant further monitoring by the IM to determine if the projects can be completed within the defined Program timeline. PSE&G continues to work with its switchgear vendor to receive updated information on the status of the remaining deliveries and has also instructed the vendor to prioritize certain deliveries in order to maximize support of the project schedules.

As per N.JA.C. Section 14:3-2A.5(c)2, the IM reports are to address:

i. *The effectiveness of Infrastructure Investment Program investments in meeting project objectives;*

ii. *The cost-effectiveness and efficiency of investments;*
iii. *The appropriateness of cost assignments; and*
iv. *Any other information required by the Board.*

The IM focuses the majority of the discussion within each report on these primary objectives, after introducing summarized the findings on these areas in the IM 2021 Third Quarter Report, the IM will continue to provide a summary on these areas for each report with an emphasis on new information relative to the current reporting period. These summarized findings are as follows:

- **Effectiveness of ES 2 investments in meeting project objectives**: The objectives for each subprogram within the ES 2 were defined within PSE&G's ES 2 filing and confirmed by the Stipulation. The overall objectives focused on improving system resiliency, reliability, and hardening through rebuilding or replacing selected substations, installing smart control and monitoring devices on distribution circuits (reclosers, fuse savers, etc.), installing ADMS and a new communication system, and rebuilding selected Gas M&R stations. Within **Section III** of this report, the IM provides a review of the status of the efforts performed to meet these objectives for each subprogram. During the third quarter of 2022, the following projects/scopes were placed in-service and/or completed:
    - Electric Station Flood Mitigation: Academy Street, Market Street, and Ridgefield 4kV previously placed in-service in 2021. The next projects forecasted to go in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each of which continues to be forecasted to go in-service by the end of 2022.
    - Contingency Reconfiguration: Following the completion of the recloser scope in early 2022, the Fuse Saver installations continued with 286 units installed during the quarter (412 units installed on the Program in total out of a currently planned scope of 1,574 units).
    - Grid Modernization – Communication System: the final 48 substation RTU retrofits were completed during the quarter (bringing the total to 218 substations in the Program); the final fiber cutover project was completed out of 12 total projects; and, two additional fiber projects were completed, leaving five projects remaining out of a total scope of 34 projects.
    - Electric Stipulated Base: Three of the five life cycle projects remain forecasted to go in-service by the end of 2022; the other two projects have shifted to 2023 forecasted in-service dates based on updated equipment delivery schedules and design changes.
    - Gas M&R: Westampton previously placed in-service in October 2021, the next stations forecasted for completion are the Camden and East Rutherford stations that continue to be forecasted to go in-service by the end of 2022.

- **Cost-effectiveness and efficiency of investments**: To assess the cost effectiveness and efficiency of ES 2 investments, the IM began with a review of the initial scope, estimate, and related planning documents for each project to establish a baseline to monitor progress against as the work advances. As the Program execution advances, the IM continues to evaluate actual costs against the initial estimates and current forecasts, including seeking additional information relating to any variances identified. The overall Program's current cost forecast now is slightly above the Stipulation amount, reflecting the cost increases that as observed by the IM has largely

stemmed from scope evolution and/or more detailed estimates from the time of the ES 2 filing, as well as the more recent changes in general market conditions (e.g. Covid-19 impacts, supply chain issues, etc.). The updated subprogram forecasts as of the end of the third quarter of 2022 compared to the end of the prior quarter were as follows:

- Electric Station Flood Mitigation: subprogram forecast decreased approximately $1.2 million (or -0.3%) to approximately $356.9 million.
- Contingency Reconfiguration: subprogram forecast increased approximately $2.0 million (or 1.4%) to approximately $147.6 million.
- Grid Modernization – Communication System: subprogram forecast increased approximately $285K (or 0.4%) to approximately $66.6 million.
- Grid Modernization – ADMS: subprogram forecast increased approximately $7.4 million (or 13.9%) to approximately $60.9 million.
- Electric Stipulated Base: subprogram forecast increased approximately $1.5 million (or 1.5%) to approximately $100.6 million.
- Gas M&R: subprogram forecast increased approximately $6.0 million (or 5.8%) to approximately $110.3 million.

As shown above, the biggest subprogram forecast changes during the second quarter of 2022 were in the Grid Modernization – ADMS and Gas M&R subprograms. Within the Grid Modernization – ADMS subprogram, the forecast increase reflected the impacts associated with a change from one OMS production release to two releases. Within the Gas M&R subprogram, the forecast increase primarily relates to the scope changes and related execution requirements identified through the development of detailed design for the Camden and East Rutherford projects.

- **Appropriateness of cost assignments**: The IM receives and reviews recurring data concerning the accumulation of costs within the Program. Based on that review, the IM submits follow-up questions to the Company regarding that data for the reporting period. Such follow-up questions generally focus on the following aspects:
  - Review of any unusual changes in cost elements from period-to-period, including but not limited to allowance for funds used during construction (AFUDC), cost of removal (COR), and the allocation of overheads.
  - Review spend on capital accounts, such as Construction Work in Progress (CWIP) as it relates to overall spend, AFUDC, and COR.
  - Verify cost accumulations and classifications appear to be in accordance with Generally Accepted Accounting Principles (GAAP), to the extent the IM has access to such information.
  - Review and investigation of prior period adjustments and/or corrections to capital accounts.
  - Engage the Company's Internal Audit group on specific areas to audit, review, and assess – particularly for areas in which the IM has limited or no visibility (proprietary data, accounting systems, etc.).

Through the above steps, the IM tracks and monitors how the Company is recording costs to support the finding that the cost assignments appear to be appropriately applied. These cost items are discussed further within **Section II.C** of this IM report.

As noted in the IM 2020 First Quarter Report, the IM conducts its assessment in accordance with Generally Accepted Government Auditing Standards (GAGAS, or more commonly referred to as the "Yellow Book" standards). The Yellow Book provides a framework for conducting performance management reviews/audit engagements with competence, integrity, objectivity, and independence that result in information used for oversight, accountability, transparency, and improvements of the audited programs and operations. On September 7, 2023, a draft IM 2022 Third Quarter Report was submitted to PSE&G, BPU Staff, and Rate Counsel. Per the Yellow Book, the transmittal of a draft report is intended to allow for review and comment by the audited entity and others to develop a fair, complete, and objective report. A summary of the comments on the draft report and the IM's responses are provided in **Appendix A – Draft Report Comments and Responses**. This **Appendix A** also identifies specific sections within this IM 2022 Third Quarter Report that have been edited, supplemented with additional information, or otherwise revised in response to the comments received.

II. Program Status

A. Key Decisions

In order to capture formalized key decisions regarding the ES 2 Program, PSE&G completes a "Record of Decision" (ROD) that includes a description of the decision; alternatives considered; the decision made; and rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact to the Program. In addition, the IM may request PSE&G complete a ROD to formalize a decision if such a decision has not yet been formalized through the ROD process.

The current and pending RODs as of the date of this IM 2022 Third Quarter Report are presented below in **Table 3 – ES 2 Records of Decisions**.

Table 3 – ES 2 Records of Decisions

Subprogram	Record of Decision	IM Comments
Electric Station Flood Mitigation	Academy Street & State Street Change in Mitigation Method	Reasonable and appropriate *(See Section B.1. in the IM 2020 First Quarter Report)*
Electric Station Flood Mitigation	Engineering Support for Energy Strong Program Projects	Reasonable and appropriate *(See Section B.2. in the IM 2020 First Quarter Report)*
Grid Modernization – Communication System	Wireless Communication Network	Reasonable and appropriate *(See Section II.A.1. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Substation Communication Center	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Third Quarter Report)*
Grid Modernization – Communication System	Fiber Scope	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Third Quarter Report)*
Electric Station Flood Mitigation	Constable Hook, Lakeside, & Orange Valley Change in Mitigation Method	Reasonable and appropriate *(See Sections II.A.3. and IV.B. in the IM 2020 Third Quarter Report and*

Subprogram	Record of Decision	IM Comments
		additional discussion in Section II.A.1. and Section IV.B. of the IM 2020 Fourth Quarter Report)
Grid Modernization – Communication System	Communication Retrofit of Replacement and non-ES-II Units	Reasonable and appropriate *(See Section II.A.2. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Market Street Radioactive Soil Testing and Handling	Reasonable and appropriate *(See Section II.A.3. in the IM 2020 Fourth Quarter Report)*
Electric Station Flood Mitigation	Transfer of Clay Street Wastewater Wall Scope from ES2FM to Clay Street 69kV Project	Reasonable and appropriate *(See Section IV.A. in the IM 2020 Fourth Quarter Report)*
Contingency Reconfiguration	Energy Strong II Electric Program – Contingency Reconfiguration Subprogram, 13kV and 4kV Reclosers	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.1. in the IM 2021 Second Quarter Report)*
Grid Modernization – ADMS	Outage Management System (OMS) Implementation	Reasonable and appropriate *(See Section IV.A. in the IM 2021 First Quarter Report and Section II.A.2. the IM 2021 Second Quarter Report)*

During the third quarter of 2022, there were no additional RODs issued.

B. Program Management

Beginning in July 2020, the IM began participating in a bi-weekly call with PSE&G to review its bi-weekly ES 2 Program Dashboard. As with the original Energy Strong Program, the Dashboard provides a mechanism for PSE&G to monitor and control activities to be completed in order to achieve key near-term milestones, including a focus on recently completed activities, any key issues, and other key metrics (e.g. installation targets) as appropriate. These calls have proven to be an effective way for the IM to stay informed on current and upcoming activities and to allow a venue for discussions between the IM and PSE&G on these activities and status updates and continue to be held on a recurring basis.

During the third quarter of 2022, PSE&G hosted the IM for meetings with subprogram personnel to review the status of the Program to date and outlook going forward. The meetings were conducted at PSE&G's Edison Training Center, which also allowed a visit to the ADMS training room to see the ADMS Platform in use in a simulated environment. In addition, site visits were conducted at the Ridgefield 13kV and State Street substations and the Westampton Gas M&R station.

C. Cost Assignments

1. Costs of Removal (COR)

Costs of Removal (COR) generally include costs for such activities as environmental removal, removal of inside station equipment, structures, foundations, towers and fixtures, conductors and other electrical devices, poles and fixtures, transformers, plant demolition, foundations, and removal of underground conduit and other wiring. Generally, COR are charged to Accumulated Depreciation and are amortized and recovered through a component of depreciation expense. The specific method and amount of recovery is determined in gas and electric rate cases before the BPU.

Table 4 – ES 2 Program Costs of Removal as of September 30, 2022, below itemizes the charges to COR for the third quarter of 2022, the second quarter of 2022 (for comparative purposes), total COR to date for 2022, total COR for the years 2021, 2020, 2019, and total ES 2 Program COR to date. These amounts do not reflect any salvage value reductions, which have been *de minimis* in the ES 2 program through September 30, 2022 (approximately $0.3 million).

Table 4 – ES 2 Program Costs of Removal as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total COR
	(in $ thousands)							
Electric Station Flood Mitigation	$397.2	$595.7	$873.4	$1,866.3	$5,558.7	$1,021.1	$0	**$8,446.1**
Contingency Reconfiguration	$213.5	$35.7	$229.3	$478.5	$2,250.2	$2,198.9	$431.0	**$5,358.6**
Grid Modernization – Communications	$5.3	$14.0	$11.0	$30.3	$137.8	$24.4	$0	**$192.5**
Grid Modernization – ADMS	$0	$0	$0	$0	$0	$0	$0	**$0**
Electric Stipulated Base	$183.1	$340.5	$370.0	$893.6	$150.0	$0	$0	**$1,043.6**
Gas M&R Station Upgrades	$763.0	$0	($0.4)	$762.6	$148.9	$0	$0	**$911.5**
Gas Stipulated Base	$0	$0	$431.5	$431.5	$196.1	$0	$0	**$627.6**
Total	**$1,562.1**	**$985.9**	**$1,914.8**	**$4,462.8**	**$8,441.7**	**$3,244.4**	**$431.0**	**$16,579.9**

Approximately half of the $1.6 million in COR activities in the third quarter of 2022 related to activities at the East Rutherford M&R project for demolition and removal costs associated with the regulator building and foundation, heaters, and yard piping.

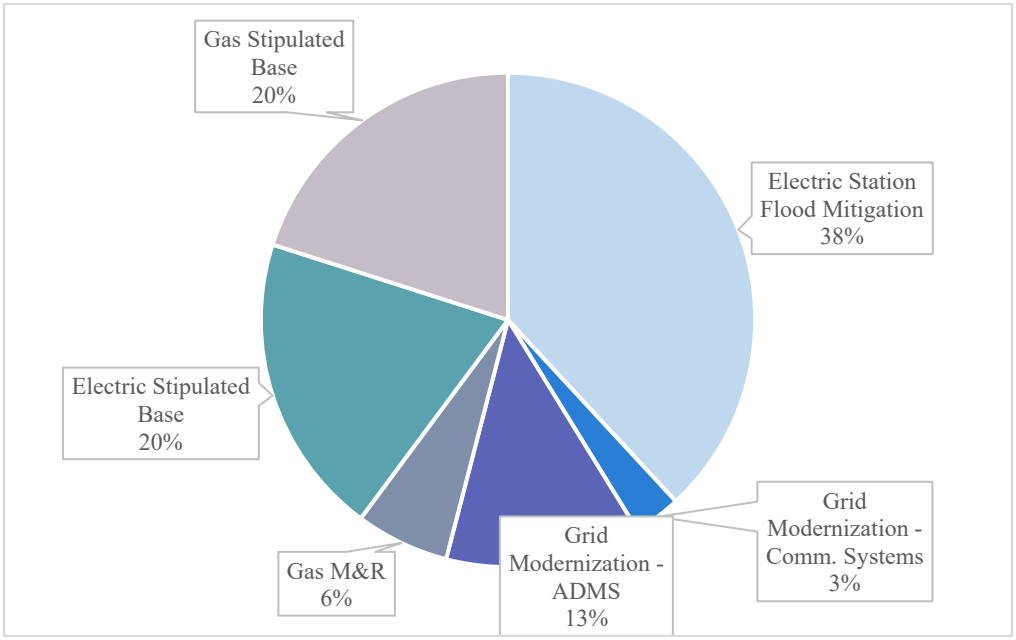
2. Construction Work-in-Progress (CWIP) & In-Service Transfers

As of September 30, 2022, the ES 2 CWIP balance was $260.7 million, compared to $184.9 million as of June 30, 2022. This is the highest balance of CWIP to date in the ES 2 program. The largest components of CWIP as of September 30, 2022 were within:

- The Electric Station Flood Mitigation projects, including: Hasbrouck Heights ($14.6 million), State Street ($12.2 million), Clay Street ($13.5 million), and Waverly ($18.0 million).
- The Gas M&R projects, including: East Rutherford ($14.2 million), Central ($23.7 million), and Camden ($27.2 million) (the latter of which is part of the Gas Stipulated Base).
- The Lifecycle Station Upgrade projects under Electric Stipulated Base, including: Hamilton ($13.1 million) and Plainfield ($16.4 million).
- The ADMS subprogram ($33.4 million).

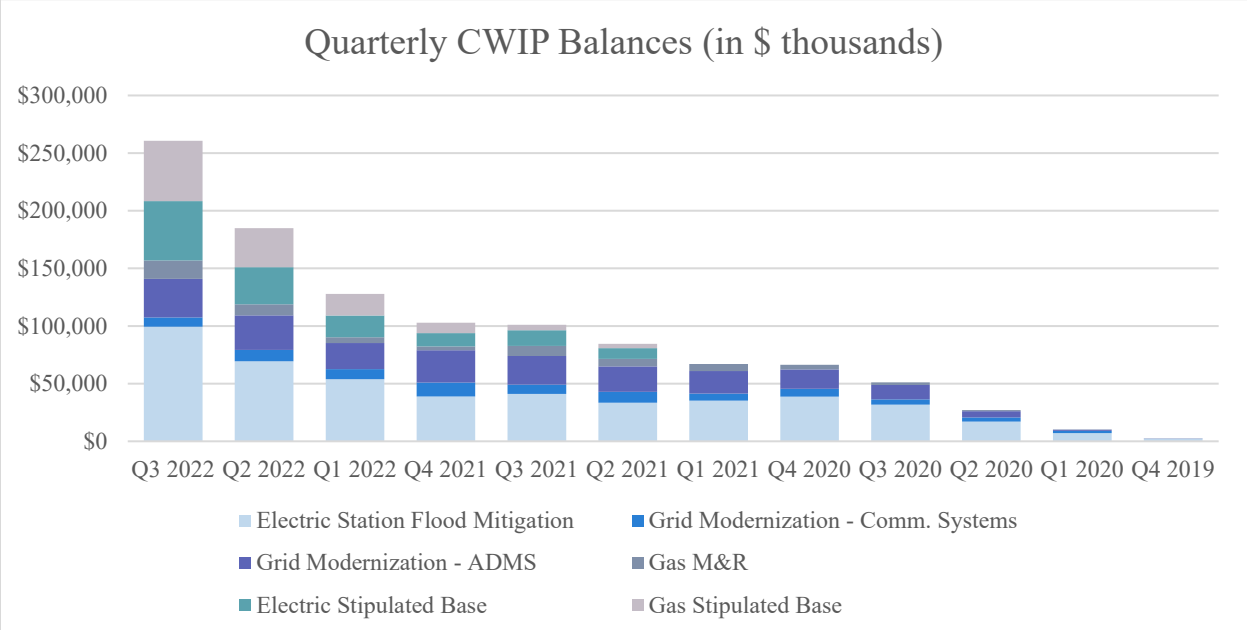
The Electric Station Flood Mitigation subprogram comprises the largest component of total end of period CWIP outstanding, as depicted in **Figure 1 – ES 2 CWIP as of September 30, 2022** below.

Figure 1 – ES 2 CWIP as of September 30, 2022



In addition, the **Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2022** below depicts the composition of end-of-quarter CWIP balances by subprogram for the third, second and first quarters of 2022, and each quarter of 2021 and 2020, and the fourth quarter of 2019.

Figure 2 – ES 2 CWIP Balances by Subprogram as of September 30, 2022



	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Electric Station Flood Mitiga	$99,393	$69,358	$ 53,834	$ 38,947	$ 41,077	$ 33,531	$ 35,299	$ 38,727	$ 31,860	$ 17,149	$ 7,101	$ 1,987
Grid Modernization - Comm.	$ 8,080	$ 9,872	$ 8,847	$ 11,991	$ 8,077	$ 9,343	$ 6,026	$ 6,760	$ 4,529	$ 3,508	$ 1,908	$ 75
Grid Modernization - ADMS	$33,396	$30,010	$ 22,534	$ 28,057	$ 24,817	$ 22,085	$ 19,600	$ 16,837	$ 12,502	$ 5,428	$ 969	$ 36
Gas M&R	$15,984	$ 9,642	$ 5,086	$ 3,338	$ 8,735	$ 6,574	$ 6,123	$ 4,032	$ 2,149	$ 951	$ 291	$ 53
Electric Stipulated Base	$51,540	$32,179	$ 18,841	$ 11,560	$ 13,645	$ 9,280	$ -	$ -	$ -	$ -	$ -	$ -
Gas Stipulated Base	$52,329	$33,854	$ 18,757	$ 9,042	$ 4,691	$ 3,808	$ -	$ -	$ -	$ -	$ -	$ -

Transfers from CWIP to plant in service were $3.1 million during the third quarter of 2022, the majority of which was attributed to placing several Grid Modernization fiber projects in service during the third quarter. Total ES 2 transfers from CWIP have been $89 million through September 30, 2022. It should be noted that work related to certain assets, such as the reclosers under the Contingency Reconfiguration subprogram, generally can be completed without being recorded through CWIP. As such, no AFUDC is recorded on these expenditures. This accounting treatment is in accord with generally accepted accounting principles and the Company's accounting policies.

3. Allowance for Funds Used During Construction (AFUDC)

The amount of quarterly AFUDC recorded by the Company for each ES 2 subprogram during the third, second, and first quarters of 2022, total 2022 to date, total AFUDC for the years 2021, 2020 and 2019, and total Energy Strong AFUDC accrued to date, is shown below in **Table 5 – ES 2 Program AFUDC as of September 30, 2022**.

Table 5 – ES 2 Program AFUDC as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YTD)	Total 2021	Total 2020	Total 2019 (Q4)	Total AFUDC
	(in $ thousands)							
Electric Station Flood Mitigation	$1,285.1	$944.5	$759.0	$2,988.6	$2,281.2	$936.5	$9.9	**$6,216.2**
Contingency Reconfiguration	$0	$0	$0	$0	$0	$0	$0	**$0**
Grid Modernization – Communications	$98.5	$123.1	$115.6	$327.2	$386.9	$184.3	$0.2	**$898.6**
Grid Modernization – ADMS	$536.9	$438.9	$385.7	$1,361.5	$1,365.6	$352.7	$0.1	**$3,079.9**
Electric Stipulated Base	$645.0	$383.9	$230.0	$1,258.9	$524.6	$44.0	$0	**$1,827.5**
Gas M&R Station Upgrades (incl. Stip. Base)	$733.8	$395.6	$208.3	$1,337.7	$470.0	$70.0	$0.2	**$1,877.9**
Total	**$3,229.3**	**$2,286.0**	**$1,698.6**	**$7,283.9**	**$5,028.3**	**$1,587.5**	**$10.4**	**$13,910.1**

AFUDC accrued for ES 2 projects during the third quarter of 2022 increased over AFUDC accrued during the second quarter of 2022 as the result of increases in total average CWIP balances across almost all subprograms.

During the first quarter of each year, the AFUDC rate is reviewed for possible reset as it applies to the current year based on updated capital structure and component cost data. For the year 2022, the new AFUDC rate was calculated to be 6.92%, using the capital structure and component costs as of January 31, 2022. This rate is higher than the 2021 rate of 6.81%, primarily due to a zero balance of short-term in the 2022 calculation (vs. a $44 million balance of short-term debt in 2021), and also to an 8% reduction in the Company's amount of long-term debt outstanding (lowering the debt component of the capital structure from 45.5% to 44.8%), and a reduction in the embedded cost of long-term debt, both as used in the AFUDC calculation. In calculating the 2022 AFUDC rate, the Company used (i) a 3.63% embedded

cost of long-term debt (vs. 3.85% in 2021), (ii) no short-term debt, and (iii) a cost of equity of 9.60% (unchanged from 2021).

Subsequent to the annual reset calculation referred to above, and during the course of each year, the AFUDC rate is also recalculated as it applies to each fiscal quarter. If the recalculated rate changes by 25 basis points from the rate then in effect, the rate is reset and retroactively applied to January 1 of that year. For the third quarter of 2022, based on data as of September 30, 2022, the recalculated weighted average AFUDC accrual rate (6.92%) did not meet this criterion to warrant changing from the annual rate (6.92%) in effect. Therefore, AFUDC was accrued during the third quarter of 2022 at the calculated rate of 6.92%.

The IM observes that the Company's calculation of the AFUDC rate and its application is in accordance with both PSE&G's accounting policy and Plant Instruction 3(17) of the Federal Regulatory Commission's Uniform Systems of Accounts prescribed for public utilities.

The IM also notes that the relevant AFUDC information as it relates to third quarter 2022 ES 2 project costs is consistent with the applicable dictates of the Stipulation entered into with respect to these Energy Strong projects. The IM will continue to review future ES 2 AFUDC accruals for consistency with relevant provisions of the Stipulation for accounting and reporting purposes only, and not as a party to, or in expressing an opinion concerning, any rate proceedings.

4. Allocated Overheads

PSE&G follows a philosophy of allocating overhead costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit, but where direct charging of costs is not feasible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order in July 2003. This Order was amended by a BPU Order dated June 8, 2022, allowing the company to transfer certain employees to the PSE&G Service Company in an effort to better support transmission growth opportunities and projects. This action had no impact on existing overhead allocations. The Stipulation requires the Company to follow its current practices with regard to capitalized overheads.

For ES 2 electric and gas distribution projects, allocated overhead costs should primarily come from utility-related labor costs associated with administrative and supervisory personnel, labor and other costs associated with bargaining unit personnel, fringe benefits, materials handling costs, payroll taxes and depreciation expense. Shown below in **Table 6 – ES 2 Program Overhead Allocations as of September 30, 2022** are the allocated overhead costs charged to ES 2 subprograms for the first three quarters of 2022, total 2022 year to date, total 2021, total 2020, total 2019 and total ES 2 Program allocated overheads to date.

Table 6 – ES 2 Program Overhead Allocations as of September 30, 2022

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YDT)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Electric Station Flood Mitigation	$3,324	$2,208	$2,185	$7,717	$14,368	$14,023	$287	**$36,395**
Contingency Reconfiguration	$3,037	$795	$843	$4,675	$14,420	$17,109	$3,415	**$39,619**

Subprogram	Q3 2022	Q2 2022	Q1 2022	Total 2022 (YDT)	Total 2021	Total 2020	Total 2019 (Q4)	Total Overhead Allocations
	(in $ thousands)							
Grid Modernization – Communications	$553	$717	$1,802	$3,073	$9,171	$3,625	$12	**$15,881**
Grid Modernization – ADMS	$50	$124	$76	$250	$501	$426	$11	**$1,188**
Electric Stipulated Base	$2,751	$1,275	$1,449	$5,476	$2,123	$259	$0	**$7,858**
Gas M&R Station Upgrades (incl. Stip. Base)	$435	$339	$197	$971	$735	$291	$15	**$2,012**
Total	**$10,149**	**$5,458**	**$6,552**	**$22,159**	**$41,318**	**$35,733**	**$3,740**	**$102,950**

The overwhelming majority of overhead costs allocated to ES 2 projects during the third quarter of 2022 are costs allocated from areas that support all utility distribution and transmission projects, including ES 2 projects. More specifically, most (approximately 77%) of the third quarter allocated costs reflect labor costs of supervisory, administrative and operations planning personnel, labor and other costs from bargaining unit personnel, and fringe benefits associated with these labor costs. The increase in overhead costs for the third quarter of 2022 from the second quarter of 2022 reflects (i) an increase in construction activities at a number of Electric Station Flood Mitigation and Electric Stipulated Base projects, which resulted in higher labor costs and outside services subject to surcharge (including contract labor), and (ii) an increase in the number of installed fuse savers in the Contingency Reconfiguration subprogram, which increased the spend on labor and materials subject to surcharge. The major categories of overhead costs incurred in the second and third quarters of 2022 by subprogram are provided below in **Table 7 – Q2 and Q3 2022 Overhead Cost Comparison**.

Table 7 – Q2 and Q3 2022 Overhead Cost Comparison

Overhead Category*	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communications	Grid Modernization – ADMS	Electric Stipulated Base	Gas M&R (incl Stip. Base)	Total
			Q2 2022 (in $ thousands)				
AMCS	$102	$19	$31	$2	$70	$43	$268
Fleet	$89	$69	$41	$8	$43	$0	$250
Fringe	$370	$115	$91	$41	$171	$116	$903
Labor & Outside Services	$1,081	$199	$303	$22	$732	$117	$2,453
Labor Only	$319	$256	$168	$27	$150	$0	$921
Material Handling	$31	$37	$6	$0	$15	$5	$93
Payroll Tax	$91	$30	$23	$10	$41	$29	$224
Toolkit and Other Services	$72	$22	$17	$7	$35	$25	$179

Overhead Category*	Electric Station Flood Mitigation	Contingency Reconfiguration	Grid Modernization – Communications	Grid Modernization – ADMS	Electric Stipulated Base	Gas M&R (incl Stip. Base)	Total
Vehicle Depreciation	$52	$49	$37	$6	$18	$4	$167
Other	$0	$0	$0	$0	$0	$0	$0
Total	**$2,208**	**$795**	**$717**	**$124**	**$1,275**	**$339**	**$5,458**
Q3 2022 (in $ thousands)							
AMCS	$176	$76	$26	$0.3	$167	$71	$517
Fleet	$115	$277	$34	$0.6	$99	$5	$530
Fringe	$499	$416	$53	$30	$291	$142	$1,431
Labor & Outside Services	$1,824	$746	$264	$2	$1,634	$112	$4,581
Labor Only	$384	$948	$123	$3	$346	$19	$1,824
Material Handling	$46	$204	$3	$0	$19	$13	$284
Payroll Tax	$114	$100	$12	$7	$67	$33	$334
Toolkit and Other Services	$109	$83	$14	$5	$75	$33	$319
Vehicle Depreciation	$57	$188	$24	$0.7	$53	$7	$329
Other	$0	$0	$0	$0	$0	$0	$0
Total	**$3,324**	**$3,037**	**$553**	**$50**	**$2,751**	**$435**	**$10,149**

*Asset Management & Centralized Services (AMCS): labor and fringes, material, contractor, consultant or other business expenses from several areas within AMCS that provide general support to Electric, Transmission, and Gas's O&M, Capital, Third Party, and Affiliate work.
Fleet: Bargaining unit personnel that maintain the vehicles for each Division.
Fringe: Costs associated with other fringe costs, pensions, and other post-employment benefits.
Labor & Outside Services: Labor and fringes, material, other business expenses associated with administrative and general costs.
Labor Only: Travel, fuel, personal protection equipment and troubleshooter labor costs specifically related to the support of the T&D Bargaining Unit work force allocated over all T&D work.
Material Handling: Costs associated with the materials handling process.
Payroll Tax: Costs associated with payroll tax.
Toolkit and Other Services: Costs associated with purchase of personal protective equipment and personal hand tools for Bargaining Unit employees and are utilized to perform O&M, Capital, Third Party, Affiliate, and deferred work activities.
Vehicle Depreciation: Depreciation expense associated with vehicle usage in each Division.

D. System Performance

1. Current Reporting Quarter Major Events

During the third quarter of 2022, there were no Major Events reported in PSE&G's service territory.

III. Project Status

A. Electric Station Flood Mitigation

A summary of the subprogram plan as of the end of the third quarter of 2022 compared to the status as of the end of 2019, end of 2020, and end of 2021 is provided below in **Table 8 – ES 2 Electric Station Flood Mitigation Subprogram Milestone Schedule as of September 30, 2022**. Note that the Academy, Market Street, and Ridgefield 4kV projects were previously placed in-service and closed out, thus there are no further updates to these projects (which have been further called out in italics in **Table 8**).

Table 8 – ES 2 Electric Station Flood Mitigation Milestone Schedule as of September 30, 2022

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1. Academy Street	Dec. 2019		KO					C					IS		CO					
	Dec. 2020		KO		C									CO						
	Dec. 2021		KO		C						IS						CO			
	Sep. 2022		KO		C						IS		CO							
2. Clay Street	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO							C					IS				CO (Q2)
	Dec. 2021			KO							C				IS					CO (Q1)
	Sep. 2022			KO							C					IS				CO (Q1)
3. Front Street^	Dec. 2019	*Not in ES 2 Program*																		
	Dec. 2020	*Not in ES 2 Program*																		
	Dec. 2021								KO				C						IS	CO (Q2)
	Sep. 2022								KO				C							IS (Q1); CO (Q2)
4. Hasbrouck Heights	Dec. 2019		KO						C						IS		CO			
	Dec. 2020		KO									C					IS		CO	
	Dec. 2021		KO									C					IS	CO		
	Sep. 2022		KO									C			IS			CO		
5. Kingsland	Dec. 2019			KO				C			IS		CO							
	Dec. 2020			KO										C					IS	CO (Q2)
	Dec. 2021			KO											C		IS		CO	
	Sep. 2022			KO										C					IS	CO (Q2)
6. Lakeside Avenue	Dec. 2019*				KO				C										IS	CO (Q2)
	Dec. 2020						KO							C					IS	CO (Q2)
	Dec. 2021						KO							C					IS	CO (Q2)
	Sep. 2022						KO							C				IS		IS (Q1); CO (Q3)
7. Leonia	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO		C									IS		CO			
	Dec. 2021			KO		C									IS		CO			
	Sep. 2022			KO		C									IS		CO			
8. Market Street	Dec. 2019			KO				C	OS		CO									
	Dec. 2020			KO					C	OS		CO								
	Dec. 2021			KO						C/OS	CO									
9. Meadow Road	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO											C				IS	CO (Q2)
	Dec. 2021			KO										C				IS		CO (Q1)
	Sep. 2022			KO										C				IS		CO (Q1)

December 31, 2023 - ES 2 Program End Date

Project	Plan Status Point	2019		2020				2021				2022				2023				2024
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
10. Orange Valley	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020					KO										C				IS (Q1); CO (Q3)
	Dec. 2021					KO										C				IS (Q1); CO (Q3)
	Sep. 2022					KO								C						IS (Q1); CO (Q2)
11. Ridgefield 13kV	Dec. 2019			KO	C										IS		CO			
	Dec. 2020			KO	C										IS		CO			
	Dec. 2021			KO	C										IS		CO			
	Sep. 2022			KO	C										IS		CO			
12. Ridgefield 4kV	Dec. 2019			KO						C	OS			CO						
	Dec. 2020			KO	C				OS		CO									
	Dec. 2021			KO	C				OS		CO									
13. State Street	Dec. 2019		KO					C								IS				CO (Q1)
	Dec. 2020		KO						C				IS							CO (Q1)
	Dec. 2021		KO						C					IS				CO		
	Sep. 2022		KO						C						IS				CO	
14. Toney's Brook	Dec. 2019			KO						C									IS	CO (Q2)
	Dec. 2020			KO										C			IS			CO (Q2)
	Dec. 2021			KO										C			IS			CO (Q2)
	Sep. 2022			KO										C			IS		CO	
15. Waverly	Dec. 2019	*Schedule Under Development*																		
	Dec. 2020			KO			C												IS	CO (Q2)
	Dec. 2021			KO			C													IS (Q3); CO (Q1 2025)
	Sep. 2022			KO			C													IS (Q2); CO (Q4)
16. Woodlynne	Dec. 2019		KO												C				IS	CO (Q2)
	Dec. 2020		KO												C				IS	CO (Q2)
	Dec. 2021		KO												C				IS	CO (Q2)
	Sep. 2022		KO									C							IS	CO (Q1)

December 31, 2023 - ES 2 Program End Date

Legend: KO = Kickoff; C = Construction; IS = Fully In-Service (major assets in-service); OS = Out-of-Service (if eliminated); CO = Closeout
-Actuals are indicated with an underline (Note: for the Market Street and Ridgefield 4kV projects, outside plant construction began in the first quarter of 2020, the construction milestone indicated on this chart reflects inside plant construction).
***-The Dec. 2019 Lakeside Avenue project schedule was based on the original raise and rebuild mitigation strategy; the current schedule reflects the proposed mitigation method change that contemplates relocating the substation.**
^-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.

A summary of the subprogram status as of the end of the third quarter of 2022 is provided below **Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2022**.

Table 9 – ES 2 Electric Station Flood Mitigation Summary Status as of September 30, 2022

Activity	Total # of Projects	Specific Projects
Kickoff Meeting	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne

Activity	Total # of Projects	Specific Projects
Key Drawing Review	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 13kV; Ridgefield 4kV; State Street; Toney's Brook; Waverly; Woodlynne
Scope Locked	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Kingsland; Lakeside Avenue; Leonia; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
Major Equipment Purchase Orders (POs)	18*	Academy Street; Clay Street; Front Street*; Hasbrouck Heights; Kingsland; Lakeside; Leonia*; Meadow Road; Orange Valley; Ridgefield 13kV*; State Street; Toney's Brook; Waverly*; Woodlynne
Architect/ Engineer (A/E) Contract Award (or selection of PSE&G internal engineering)	16	Academy Street[1]; Clay Street[1]; Front Street[3]; Hasbrouck Heights[1]; Kingsland[2]; Lakeside Avenue[3]; Leonia[2]; Market Street[2]; Meadow Road[2]; Orange Valley[1]; Ridgefield 13kV[2]; Ridgefield 4kV[2]; State Street[2]; Toney's Brook[3]; Waverly[3]; Woodlynne[1]
Construction Start**	16	Academy Street; Clay Street; Front Street; Hasbrouck Heights; Lakeside; Leonia; Kingsland; Market Street; Meadow Road; Orange Valley; Ridgefield 4kV; Ridgefield 13kV; State Street; Toney's Brook; Waverly; Woodlynne
In-Service	3	Academy Street; Market Street; Ridgefield 4kV
Partial In-Service	2	Leonia; Ridgefield 13kV

**-Three of the listed projects (Front Street, Leonia, Ridgefield 13kV, and Waverly) have two switchgears, thus the current count reflects 18 switchgears at 14 substations.*
[1]-Indicates Burns & McDonnell is serving as the A/E.
[2]-Indicates PSE&G internal resources are serving as the A/E.
[3]-Indicates Black & Veatch is serving as the A/E.
***-Includes projects that have commenced inside plant (IP) and/or outside plant (OP) construction; also maintains identification of projects that have since completed construction (generally those that are shown as in-service).*

Beyond the key activities summarized in **Table 9** above, **Table 10 – ES 2 Electric Station Flood Mitigation Planned Activities for Q4 2022** summarizes the upcoming planned activities for each project for the fourth quarter of 2022, including any carryover of activities from earlier periods.

Table 10 – ES 2 Electric Station Flood Mitigation Planned Activities for Q4 2022

Station	Planned Activities for Q4 2022	Carryover Activities from Q3 2022
1. Academy Street	• Demolition of old station	• Demo existing foundations, remove old equipment at existing Academy St. station
2. Clay Street	• Start electrical construction	• Continue civil construction
3. Front Street	• Commission and energize contingency switchgear	• Continue to prepare the contingency switchgear
4. Hasbrouck Heights	• Energize switchgear and place in-service	• Switchgear commissioning
5. Kingsland	• Start electrical construction	• Continue civil construction
6. Lakeside Avenue	• Start switchgear foundations	• Commence civil construction
7. Leonia	• Energize switchgear and place in-service	• Continue commissioning of switchgear #2
8. Market Street	*Project complete*	
9. Meadow Road	• Install foundations, conduit, grounding, and cable trench	• Continue civil construction
10. Orange Valley	• Install duct banks, start switchgear foundation	• Continue civil construction

Station	Planned Activities for Q4 2022	Carryover Activities from Q3 2022
11. Ridgefield 13kV	• Energize switchgear and place in-service	• Continue commissioning new switchgear #1
12. Ridgefield 4kV	*Project complete*	
13. State Street	• Energize switchgear and place in-service	• Continue commissioning switchgear
14. Toney's Brook	• Install grounding grid, conduit, bus supports • Start electrical construction	• Continue civil construction
15. Waverly	• Demo existing 26kV switchgear • Cutovers to new 26kV switchgear	• Install new 26kV cables • Manhole construction
16. Woodlynne	• Continued civil construction	• Continued ductbank and manhole construction

As discussed in the IM 2022 First Quarter Report, PSE&G's switchgear vendor, Powercon, informed PSE&G that due to various material and sub-supplier delays, the remaining major equipment deliveries may continue to see impacts. Powercon continues to explore options to improve its production floor efficiencies and ordering supplies earlier to potentially alleviate further impacts. PSE&G has requested more detailed and frequent status updates from Powercon to better inform its project planning. The status of the major equipment deliveries for the Electric Station Flood Mitigation projects is presented in **Table 11 – Electric Station Flood Mitigation Major Switchgear Deliveries as of September 30, 2022**.

Table 11 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
1. Academy Street	13kV switchgear	***11/7/2020***	***11/7/2020***
2. Clay Street	4kV switchgear	8/30/2022	10/3/2022
3. Front Street	4kV switchgear	5/22/2023	8/15/2023
	4kV cont. switchgear	7/17/2022	***8/25/2022***
4. Hasbrouck Heights	4kV switchgear	***11/30/2021***	***11/30/2021***
5. Kingsland	13kV switchgear[1]	***9/30/2020***	***9/30/2020***
6. Lakeside Avenue	4kV switchgear	1/26/2023	6/30/2023
7. Leonia	13kV switchgear #1	***5/24/2021***	***5/24/2021***
	13kV switchgear #2	***6/16/2022***	***6/16/2022***
	13kV cont. switchgear[2]	***10/16/2020***	***10/16/2020***
8. Market Street	Elimination project		
9. Meadow Road	13kV switchgear[2]	2/14/2023	2/14/2023
10. Orange Valley	4kV switchgear	5/29/2023	8/15/2023
11. Ridgefield 13kV	13kV switchgear #1	8/2/2022	***8/24/2022***
	13kV switchgear #2	***4/27/2021***	***4/27/2021***
	13kV cont. switchgear[1]	***9/30/2020***	***9/30/2020***
12. Ridgefield 4kV	Elimination project		
13. State Street	4kV switchgear	***12/15/2021***	***12/15/2021***
14. Toney's Brook	4kV switchgear	12/20/2022	12/20/2022
15. Waverly	26kV switchgear	***4/30/2021***	***4/30/2021***
	4kV switchgear	8/5/2022	10/31/2022
16. Woodlynne	4kV switchgear	11/22/2022	2/6/2023

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
Note: bold/italicized dates indicate actual delivery dates. [1]The Kingsland 13kV switchgear was delivered to the Ridgefield 13kV site where it is being used as the contingency/temporary switchgear for that project before its permanent installation on the Kingsland project. Delivery of the switchgear to the Kingsland site will follow the Ridgefield 13kV project being placed in-service, which is forecasted for December 2022 with the disassembly of the contingency/temporary switchgear and delivery to Kingsland expected in the first quarter of 2023. [2]The Meadow Road project will use the Leonia project's 13kV contingency switchgear as its permanent switchgear.			

As indicated in **Table 11**, during the third quarter of 2022, there were two additional switchgear deliveries received (the contingency 4kV switchgear for Front Street and the 13kV switchgear #1 for Ridgefield 13kV), leaving eight deliveries remaining for the subprogram. Of the remaining eight deliveries, two had the forecasted delivery date unchanged from the prior quarter, while the other six all slipped between approximately three weeks and 155 days, continuing to reflect the challenges Powercon is experiencing and continuing to impact the forecasted in-service dates for these projects.

The current project estimates are shown below in **Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2022**. As discussed in the IM 2022 First Quarter Report, PSE&G decided to consolidate the R&C on the individual projects into one R&C balance for the entire subprogram, thus there is no estimated R&C amount at the project level. **Table 12** also shows the current estimate level based on PSE&G's estimating processes and as approved by the URB, the actual spend, and percentage of actuals to estimate as of the end of the third quarter of 2022.

Table 12 – ES 2 Electric Station Flood Mitigation Project Cost Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
1. Academy Street	Definitive	$9,300,000	$-	$9,300,000	$7,997,585	$6,519,897	70%
2. Clay Street	Definitive	$33,600,000	$-	$33,600,000	$33,613,927	$13,021,870	39%
3. Front Street**	Study	$25,900,000	$-	$25,900,000	$27,500,832	$9,558,510	37%
4. Hasbrouck Heights	Definitive	$19,300,000	$-	$19,300,000	$19,073,778	$13,926,106	72%
5. Kingsland	Conceptual	$8,700,000	$-	$8,700,000	$8,993,293	$2,219,794	26%
6. Lakeside Avenue	Study	$39,400,000	$-	$39,400,000	$32,706,175	$3,292,610	8%
7. Leonia	Definitive	$24,900,000	$-	$24,900,000	$25,680,491	$22,304,216	90%
8. Market Street	Definitive	$29,100,000	$-	$29,100,000	$28,308,684	$28,140,833	97%
9. Meadow Road	Conceptual	$7,200,000	$-	$8,300,000	$8,406,000	$2,035,052	25%
10. Orange Valley	Study	$14,700,000	$-	$14,700,000	$14,903,289	$2,227,908	15%

Project	Estimate Level	Base	Risk & Contingency*	Total	Current Forecast	Actuals to Date	% of Actuals to Estimate
11. Ridgefield 13kV	Conceptual	$26,100,000	$-	$26,100,000	$28,244,833	$25,524,755	98%
12. Ridgefield 4kV	Definitive	$20,700,000	$-	$20,700,000	$20,703,808	$20,703,809	100%
13. State Street	Definitive	$19,600,000	$-	$19,600,000	$19,837,904	$11,609,902	59%
14. Toney's Brook	Conceptual	$16,200,000	$-	$16,200,000	$16,250,514	$3,034,991	19%
15. Waverly	Conceptual	$39,900,000	$-	$39,900,000	$40,738,565	$17,197,448	43%
16. Woodlynne	Definitive	$24,000,000	$-	$24,000,000	$23,964,496	$5,986,596	25%
ES 2 Station Placeholder	N/A	$-	$29,300,000	$29,300,000	$-	$-	-
Subprogram Total		**$359,700,000**	**$29,300,000**	**$389,000,000**	**$356,924,105**	**$187,304,230**	**48%**

**-As discussed in Section II.B. of the IM 2022 First Quarter Report, PSE&G made the decision to hold risk and contingency at the subprogram level, which resulted in updated estimates being prepared for each project to reflect this change and other project-specific updates as warranted.*

***-The Front Street project was proposed by PSE&G during the second quarter of 2021 to replace the cancelled Constable Hook project.*

Findings & Observations

- No change in completed projects during the third quarter of 2022, with three of the 16 projects previously put in-service (Market Street and Ridgefield during the second quarter of 2021 and Academy Street in the fourth quarter of 2021). The next projects forecasted to be placed in-service are the Hasbrouck Heights, Leonia, Ridgefield 13kV, and State Street projects, each continues to advance towards a forecasted in-service date in the fourth quarter of 2022.
- Five additional projects commenced construction during the third quarter of 2022 (Kingsland, Lakeside Avenue, Meadow Road, Orange Valley, and Toney's Brook), with that all projects in the subprogram have passed the construction start milestone.
- Twelve of the remaining thirteen Electric Station Flood Mitigation projects had movement in the forecasted in-service date during the third quarter of 2022, with four advancing and eight slipping. For three of those projects, the change was less than one week, while the biggest changes involved the following projects:
    - Lakeside Avenue (slipping 163 days to February 28, 2024);
    - Waverly (slipping 62 days to April 20, 2024);
    - Front Street (slipping 62 days to January 9, 2024); and,

- Clay Street (slipping 52 days to March 23, 2023).

Of those four projects, all but Clay Street had switchgear delivery delays (while Clay Street had combined impacts from a safety incident, weather impacts, and additional test pits required). As previously discussed, PSE&G updates the schedule on a monthly basis based on the current data and information available and assesses opportunities to improve the schedule as part of this process.

- The overall subprogram forecast as of the end of the third quarter of 2022 decreased $1.2 million (or -0.3%) to $356.9 million from the status as of the prior quarter. The forecast continues to remain under the current subprogram estimate and Stipulation amount of $389.0 million (which includes $29.3 million in R&C). The change in the subprogram forecast was predominantly driven by changes to the project forecasts on four of the projects, including:
  - Front Street (increased $1.3 million to $27.5 million): driven by an updated Division forecast for bringing six circuits from OP to IP, additional handling of contingency feeder rows, and additional costs for contingency wire checker and contingency disassembly.
  - Lakeside Avenue (decreased $2.2 million to $32.7 million): driven by lower OP Division cost stemming from 15% decrease in the linear footage of underground cable required and removing the contingency no longer required.
  - Orange Valley (decreased $2.2 million to $27.5 million): driven by a reallocation of civil and electrical costs between the Orange Valley and Orange Heights projects.
  - Waverly (increased $827K to $40.7 million): driven by more civil work required to rebuild a manhole and escalation in A/E procured steel and cable trench prices.
- With 52% of the subprogram forecast now spent (48% of the Stipulation amount), the IM has found nothing to date that would jeopardize the subprogram being completed on budget as even with some cost pressures on certain projects, there is adequate R&C remaining in the subprogram. However, the schedule status of the later projects in this subprogram, and in particular those with open switchgear deliveries currently forecasted for 2023 will have to continue to be closely followed to monitor if the projects can be completed within the ES 2 Program window. At this time, the primary risk to the project schedule is those major equipment deliveries, followed by resource availability to support schedule requirements and weather-related impacts. Delays to the switchgear deliveries have caused the forecasted in-service dates for Front Street, Lakeside Avenue, Orange Valley, and Waverly to slip into 2024. While the resource risk is primarily within the Metro Division (potentially impacting Lakeside, Clay Street, Waverly, Orange Valley, and Tone's Brook) and Southern Divisions (potentially impacting State Street, Woodlynne, and Woodbury).
- Regarding the projects with remaining switchgear deliveries, PSE&G continues to meet regularly with its vendor to receive updated information as to the status of these deliveries. PSE&G has also worked with the vendor to re-prioritize certain deliveries to optimize the project schedules and advanced the in-service date if possible. During the third quarter of 2022 the 4kV contingency switchgear was received at Front Street and 13kV switchgear #1 was received at Ridgefield 13kV. Of the remaining eight switchgear deliveries, six of the eight saw the forecasted delivery date slip from the status as of the end of the prior quarter (while the other two remained constant).

1. Academy Street

During the third quarter of 2022, $114,926 was spent on the Academy Street project compared to a forecast of approximately $71,000, which brought the total spend to approximately $6.5 million.

This project was placed in-service on October 19, 2021, and in the third quarter of 2022 the final circuit was cutover to the switchgear. The demolition of the old substation is expected to commence in October 2022, with the PO associated with this work issued in August 2022.

The actual spend by period for Academy Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. The Academy Street forecast decreased approximately $500,000 during the third quarter of 2022, which was the result of the civil and electrical demolition POs being lower than estimated.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$150,398	$4,224,550	$1,754,789	$131,061	$144,172	$114,926	$1,435,688	$42,000

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$9,300,000	$6,519,897	70%
Forecast	$7,997,585		82%

2. Clay Street

During the third quarter of 2022, $2,238,630 was spent on the Clay Street project compared to a forecast of approximately $3.0 million, which brought the total spend to approximately $13.0 million. The variance in forecasted to actual spend during the third quarter of 2022 was largely driven by the delivery of the feeder rows being delayed from September to October 2022.

The forecasted in-service date for the Clay Street project as of the end of the third quarter of 2022 slipped 52 days from the status as of the end of the prior quarter to March 23, 2023. The slip in forecasted in-service date was the combined result of a safety incident on the project, weather impacts in the outside plant civil work that delayed the installation of the switchgear building foundation, and a requirement for additional test pits to confirm the OP underground design.

The primary activities on the Clay Street project during the third quarter of 2022 included the continued advancement of the civil construction, with foundation and duct bank installations performed during the quarter, and the start of work on the switchgear building.

The actual spend by period for Clay Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Clay Street project transitioned to the Definitive level estimate, which resulted in the base estimate increasing from $30.8 million to $33.6 million. This $2.8 million increase was driven by:

- Electrical construction award higher than estimated ($0.8 million);
- Higher revised Division estimate ($0.7 million);
- Project schedule recovery ($0.6 million);

- Higher A/E procured equipment award ($0.4 million);
- Addition of Human-Machine Interface (HMI) to the switchgear PO ($0.2 million); and
- Addition of a contingency capacitor bank ($0.1 million).

Regarding the "project schedule recovery" item listed above, this was comprised primarily in additional construction contractor costs (approximately $475K), with the remainder related to civil and electrical supervision costs. These efforts recovered three months in the project schedule from the six-month delay encountered.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$116,409	$879,339	$2,806,593	$5,044,642	$1,936,258	$2,238,630	$8,640,123	$11,987,934

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$33,600,000	$13,021,870	39%
Forecast	$33,613,927		39%

3. Front Street

During the third quarter of 2022, $5,887,539 was spent on the Front Street project compared to a forecast of approximately $5.4 million, which brought total spend to approximately $9.6 million. The higher than forecasted spend during the third quarter of 2022 was attributed to higher than forecasted overhead labor involved with bringing the six circuits from OP to IP.

The forecasted in-service date for the Front Street project as of the end of the third quarter of 2022 slipped 62 days from the status as of the end of the prior quarter to January 9, 2024. This change in the forecasted in-service date was the result of delays to the Powercon switchgear delivery from May 2023 to August 2023, which pushed the project's critical path out.

The primary activities on the Front Street project during the third quarter of 2022 included:

- Contingency switchgear delivered;
- Civil and electrical drawings issued for construction (IFC); and,
- Commencement of electrical construction (for the contingency switchgear).

The actual spend by period for Front Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$-	$-	$2,351,832	$429,607	$889,533	$5,887,539	$2,385,947	$15,556,375

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$25,900,000	$9,558,510	37%
Forecast	$27,500,832		35%

4. Hasbrouck Heights

During the third quarter of 2022, $1,958,570 was spent on the Hasbrouck Heights project compared to a forecast of approximately $2.2 million, which brought the total spend to approximately $13.9 million. The forecasted in-service date for the Hasbrouck Heights project as of the end of the third quarter of 2022 advanced 35 days from the status as of the end of the prior quarter to November 18, 2022. This advancement in the forecasted in-service date was driven by electrical construction and relay work progressing faster than expected.

Notable activities completed on the Hasbrouck Heights project during the third quarter of 2022 included:

- Switchgear set on the foundation;
- Civil construction completed;
- Commencement of switchgear commissioning;
- Delivery of regulator/reactors (partial).

The actual spend by period for Hasbrouck Heights as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$149,848	$1,129,934	$4,176,249	$4,323,599	$2,187,907	$1,958,570	$1,912,016	$3,235,656

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,300,000	$13,926,106	72%
Forecast	$19,073,778		73%

5. Kingsland

During the third quarter of 2022, $554,703 was spent on the Kingsland project compared to a forecast of approximately $1.0 million, which brought the total spend to approximately $2.2 million. The variance in forecasted to actual spend during the third quarter of 2022 was attributed to less electrical work performed than planned in September due to delays on outstanding requests for information.

The forecasted in-service date for the Kingsland project as of the end of the third quarter of 2022 slipped 35 days from the status as of the prior quarter to November 6, 2023. This slip to the forecasted in-service date was driven by resource availability constraints within the Division and intricacies in sequencing the cutovers of the circuits.

The primary activities on the Kingsland project during the third quarter of 2022 included:

- Electrical PO issued;
- Construction permits received;
- Pre-construction licenses and permit review meeting held; and,
- Commencement of civil construction.

The actual spend by period for Kingsland as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter

of 2022, the Kingsland project transitioned to the Conceptual estimate level, which resulted in the base estimate increasing from $6.4 million to $8.7 million. This $2.3 million increase was driven by:

- Unforeseen contaminated soil ($0.9 million);
- Final civil design required additional piles ($0.6 million);
- Contingency plan required for station reliability during outages ($0.6 million);
- Extended project duration: shift from Q2 2023 to Q4 2023 in-service ($0.4 million); and,
- Lower licensing and permitting needs: (-$0.2 million).

Regarding the extended project duration noted above, this was calculated based on additional carrying costs for 2023 ($25k/month) and an additional five months in 2024 for post in-service closeout ($20k/month). These carrying costs cover typical project management activities and resources (e.g. project manager, staff engineer, cost engineer, scheduler, etc.).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$104,112	$209,667	$510,943	$301,463	$538,906	$554,703	$1,924,615	$4,848,885

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,700,000	$2,219,794	26%
Forecast	$8,993,293		25%

6. Lakeside Avenue

During the third quarter of 2022, $1,536,403 was spent on the Lakeside Avenue project compared to a forecast of approximately $1.4 million. The forecasted in-service date for the Lakeside Avenue project as of the end of the third quarter of 2022 slipped 163 days from the status as of the end of the prior quarter to February 28, 2024, which was the result of a delay to the anticipated switchgear delivery from April 2023 to July 2023.

Notable activities completed on the Lakeside Avenue project during the third quarter of 2022 included:

- Electrical PO issued;
- Pre-construction licenses and permits review meeting held; and,
- Commencement of civil construction, beginning with manhole and duct bank installations.

The actual spend by period for Lakeside Avenue as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$148,943	$453,994	$570,713	$351,720	$230,836	$1,536,403	$2,101,547	$27,312,018

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$39,400,000	$3,292,610	8%
Forecast	$32,706,175		10%

7. Leonia

During the third quarter of 2022, $1,356,322 was spent on the Leonia project compared to a forecast of approximately $1.3 million, which brought the total spend to approximately $22.3 million. The forecasted in-service date for the Leonia project as of the end of the third quarter of 2022 advanced 27 days from the status at the end of the prior quarter to November 16, 2022.

Notable activities completed on the Leonia project during the third quarter of 2022 included:

- Continued installation of the new switchgear #2, including installation of the firewall, pulling cable, and manhole/conduit work; and,
- Commencement of commissioning the new switchgear #2.

The actual spend by period for Leonia as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$44,792	$6,033,379	$9,112,257	$1,789,112	$3,968,355	$1,356,322	$1,591,776	$1,784,499

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,900,000	$22,304,217	90%
Forecast	$25,680,491		87%

8. Market Street

During the third quarter of 2022, $117,836 was spent on the Market Street project compared to a forecast of approximately $203,000, which brought the total spend to approximately $28.1 million. The Market Street substation was taken out of service as of June 25, 2021.

The final punch list items and site cleanup activities were completed at the end of the second quarter of 2022, remaining costs including those incurred during the third quarter of 2022 relate to final and trailing costs related to this closeout work.

The actual spend by period for Market Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$251,193	$16,079,601	$10,681,487	$808,096	$202,619	$117,836	$121.852	$46,000

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$29,100,000	$28,140,832	97%
Forecast	$28,308,684		99%

9. Meadow Road

During the third quarter of 2022, $382,461 was spent on the Meadow Road project compared to a forecast of $335,000, which brought the total spend to approximately $2.0 million. The forecasted in-service date for the Meadow Road project as of the end of the third quarter of 2022 slipped six days from the status as of the end of the prior quarter to September 28, 2023.

The primary activities conducted on the Meadow Road project during the third quarter of 2022 included:

- Civil and electrical POs issued;
- Pre-construction licenses and permits compliance meeting held; and
- Commencement of civil construction, beginning with manhole work and the foundations for the switchgear.

The actual spend by period for Meadow Road as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Meadow Road project transitioned to the Conceptual level estimate, which resulted in the base estimate increasing from $7.2 million to $8.3 million. This $1.1 million estimate increase was driven by:

- Higher carrying costs based on current staffing plan and surcharge rates ($0.7 million);
- Increased engineering due to revisions associated with the New Jersey Department of Environmental Protection (NJDEP) permit application ($0.6 million);
- Revised estimate for testing and commissioning ($0.3 million); and,
- Lower Division estimate: (-$0.5 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$63,128	$535,081	$445,234	$288,050	$321,098	$382,461	$1,860,889	$4,510,060

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,300,000	$2,035,052	25%
Forecast	$8,406,000		24%

10. Orange Valley

During the third quarter of 2022, $1.0 million was spent on the Orange Valley project compared to a forecast of approximately $787,000, which brought the total spend to approximately $2.2 million. The variance in forecasted to actual spend in the third quarter of 2022 was primarily attributed to manhole installation and related environmental efforts for soil disposal being performed earlier than planned.

The forecasted in-service date for the Orange Valley project as of the end of the third quarter of 2022 slipped 35 days from the status as of the end of the prior quarter to February 2, 2024. This slip in the forecasted in-service date was driven by delays on the expected delivery of the switchgear from Powercon (as shown in **Table 10**).

During the third quarter of 2022, major activities on the Orange Valley project included:

- Civil and electrical construction POs issued;

- Municipal and railroad licenses and permits received; and,
- Commencement of civil construction, beginning with manhole and duct bank work.

The actual spend by period for Orange Valley as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$77,029	$362,895	$358,052	$111,565	$276,614	$1,041,753	$627,797	$12,047,584

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$14,700,000	$2,227,908	15%
Forecast	$14,903,289		15%

11. Ridgefield 13kV

During the third quarter of 2022, $3,567,625 was spent on the Ridgefield 13kV project compared to a forecast of approximately $3.6 million, which brought the total spend to approximately $25.5 million. The forecasted in-service date for the Ridgefield 13kV project as of the end of the third quarter of 2022 advanced five days from status as of the end of the prior quarter to December 8, 2022.

Notable activities performed on the Ridgefield 13kV project during the third quarter of 2022 included:

- Continued civil construction of the new switchgear #1, including installation of piles, foundations, and duct banks;
- Delivery of the new switchgear #1; and,
- Installation and commencement of commissioning of the new switchgear #1.

The actual spend by period for Ridgefield 13kV as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$205,982	$6,232,692	$10,849,681	$2,111,096	$2,557,679	$3,567,625	$1,810,079	$909,998

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,100,000	$25,524,756	98%
Forecast	$28,244,833		90%

12. Ridgefield 4kV

During the third quarter of 2022, there was no spend the Ridgefield, with the total spend remaining at approximately $20.7 million. The project was placed in-service on May 16, 2021.

The project was closed out during the third quarter of 2022 after the final closeout activities were performed during the first quarter of 2022, which included some trailing costs in the second quarter of 2022.

The actual spend by period for Ridgefield 4kV as compared to the final forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$143,414	$11,239,534	$9,263,852	$42,604	$14,405	-	-	-

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$20,700,000	$20,703,808	100%
Forecast	$20,703,808		100%

13. State Street

During the third quarter of 2022, $978,273 was spent on the State Street project compared to a forecast of approximately $815,000, which brought the total spend to approximately $11.6 million. The forecasted in-service date for the State Street project as of the end of the third quarter of 2022 advanced three days from the status of as of the end of the prior quarter to December 16, 2022.

Notable activities performed on the State Street project during the third quarter of 2022 included:

- Setting the new 4kV switchgear;
- Installation of bus supports and busses from the 4kV switchgear to the transformers;
- Installation of the grounding grid and regulators; and,
- Commencement of switchgear commissioning.

The actual spend by period for State Street as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$77,590	$662,148	$8,093,227	$751,849	$1,046,814	$978,273	$1,672,283	$6,555,719

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,600,000	$11,609,902	59%
Forecast	$19,837,904		59%

14. Toney's Brook

During the third quarter of 2022, $740,393 was spent on the Toney's Brook project compared to a forecast of approximately $973,000, which brought the total spend to approximately $3.0 million. The variance in forecasted to actual spend during the third quarter of 2022 was primarily attributed to adverse weather in September that impacted the foundation work, which in turn led to delays in the duct bank work that had been planned for the month.

The forecasted in-service date for the Toney's Brook project as of the end of the third quarter of 2022 slipped 39 days from the status as of the end of the prior quarter to May 26, 2023. The slip in the forecasted in-service date was driven by delays on the Powercon switchgear delivery (note the switchgear delivery was originally planned for early November 2022, but as of the first quarter of 2022 that had slipped to late December 2022). Delays on this switchgear were driven by unavailability of the cell kits from Powercon's supplier Eaton. PSE&G worked with its vendors to re-assign the cell kit ready for the Woodlynne switchgear to the Toney's Brook switchgear to partly mitigate this delay.

The notable activities on the Toney's Brook project during the third quarter of 2022 included:

- Pre-construction licenses and permits compliance review meeting held;
- Civil contractor mobilized and commenced work on the equipment foundations; and
- Continued engineering for the outside plant scope of work.

The actual spend by period for Toney's Brook as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$211,940	$373,096	$941,519	$138,270	$629,773	$740,393	$4,038,501	$9,177,022

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$16,200,000	$3,034,991	19%
Forecast	$16,250,514		19%

15. Waverly

During the third quarter of 2022, $8,248,435 was spent on the Waverly project compared to a forecast of approximately $8.3 million, which brought the total spend to approximately $17.2 million.

The forecasted in-service date for the Waverly project as of the end of the third quarter of 2022 slipped 63 days from the status as of the end of the prior quarter to April 30, 2024. This slip was due to manhole modifications required before the energization of the 26kV switchgear can occur and the need for Y-buses prior to the 26kV circuit cutovers to support reliability requirements and increasing the overall duration of the cutovers.

The primary activities performed during the third quarter of 2022 included:

- 4kV switchgear building delivered;
- Commissioning of the 26kV switchgear; and,
- Manhole re-design, installation, and repairs.

The actual spend by period for Waverly as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Waverly project transitioned to the Conceptual level estimate, which resulted in the Base estimate increasing from $36.2 million to $39.9 million. This $3.7 million increase was driven by:

- Higher than estimated civil construction award ($2.2 million);

- Higher revised estimate for installation of 4kV equipment due to increased market price/labor rates ($0.9 million);
- Change in surcharge methodology ($0.4 million); and,
- Additional storage and handling of the 26kV and 4kV switchgears in warehouse due to site plan revision/delay ($0.2 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$103,748	$2,460,815	$4,415,223	$432,853	$1,536,375	$8,248,435	$2,930,673	$20,610,443

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$39,900,000	$17,197,448	43%
Forecast	$40,738,565		42%

16. Woodlynne

During the third quarter of 2022, $903,898 was spent on the Woodlynne project compared to a forecast of approximately $826,000, which brought the total spend to approximately $6.0 million. The forecasted in-service date for the Woodlynne project as of the end of the third quarter of 2022 remains unchanged from the status as of the end of the prior quarter at October 10, 2023.

The primary activities performed on the Woodlynne project during the third quarter of 2022 included:

- Continued advancement of the duct bank installations that commenced in the February 2022; and,
- Commencement of manhole installations.

The actual spend by period for Woodlynne as compared to the current forecast and URB approved estimate is provided below along with the forecasted spend through the end of the project. During the third quarter of 2022, the Woodlynne project transitioned to the Definitive level estimate, which resulted in the base estimate increasing from $21.3 million to $24.0 million. This $2.7 million increase was driven by:

- Higher Division estimate ($2.1 million); and,
- Higher revised testing and commissioning estimate ($0.6 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$110,982	$993,298	$991,630	$1,639,443	$1,347,345	$903,898	$2,159,991	$15,817,908

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$24,000,000	$5,986,597	25%
Forecast	$23,964,496		25%

B. Contingency Reconfiguration

During the third quarter of 2022, the main efforts in the Contingency Reconfiguration subprogram continue to focus on the installation of additional Fuse Savers, following the completion of the recloser

scope in the first quarter of 2022. **Table 13 – ES 2 Program Fuse Saver Status as of September 30, 2022** provides a summary of the Fuse Saver scope of the Contingency Reconfiguration subprogram, indicating the number of units completed during the third quarter of 2022 and for the total program, showing the status of engineering, installation, and commissioning out of a total scope of 1,574 units, which represents a reduction of 67 units in the Fuse Savers scope. The target installations are assessed on a quarterly basis by PSE&G based on the actual costs per unit observed to date.

Table 13 – ES 2 Program Fuse Saver Status as of September 30, 2022

Type	Engineering Packages Completed (1 Fuse Saver ea.)	Fuse Savers Installed	Fuse Savers Commissioned
Q3 Qty.	283	286	285
Program Total to Date	700	412	410
Remaining	874	1,162	1,164

The installation of Fuse Savers recommenced in May 2022, following the earlier installations performed as part of the Fuse Saver pilot program in 2020-2021. As shown in **Table 13**, installations in the third quarter of 2022 ramped up significantly from the prior quarter (which was limited to 13 devices installed due to a hold placed on installations during the second quarter). This followed PSE&G's plans to add more installations than initially planned in the second half of 2022, and as previously discussed there is no significant cost impact expected from this shift in installations. PSE&G establishes installation targets on a quarterly basis, which are then split into monthly targets for each Division with the forecasts updated on a bi-weekly basis.

The current forecasted completion date for the primary components that make up the Contingency Reconfiguration subprogram are provided in **Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2022**. This table also shows the forecasted final in-service dates as of the end of the second quarter of 2022 to show movement to the forecast as of the end of the third quarter of 2022.

Table 14 – ES 2 Contingency Reconfiguration Forecasted Completion Dates as of September 30, 2022

Scope & Division		Q2 2022 Forecasted Completion Date	Q3 2022 Forecasted Completion Date
Reclosers	Central	1/31/2022 (Actual)	1/31/2022 (Actual)
	Metro	12/31/2021 (Actual)	12/31/2021 (Actual)
	Palisades	1/31/2022 (Actual)	1/31/2022 (Actual)
	Southern	1/31/2022 (Actual)	1/31/2022 (Actual)
Fuse Savers	Central	12/30/2023	12/30/2023
	Metro	12/30/2023	12/30/2023
	Palisades	12/30/2023	12/30/2023
	Southern	12/30/2023	12/30/2023

As shown in **Table 14**, the forecasted in-service dates for the Fuse Saver scope of each Division continues to be the end of 2023.

The Contingency Reconfiguration subprogram costs through the end of the third quarter of 2022 are presented in **Table 15 – ES 2 Contingency Reconfiguration Actual Costs as of September 30, 2022**.

Table 15 – Contingency Reconfiguration Actual Costs as of September 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Total to Date
		Actuals						
Reclosers	Central	$2,737,167	$12,050,820	$9,852,812	$880,537	$45,064	$46,364	$25,612,764
	Metro	$2,231,431	$10,726,610	$11,368,409	$150,325	($31,771)	($8,856)	$24,436,149
	Palisades	$2,515,569	$12,119,436	$8,280,522	($66,771)	$2,816	$500	$22,852,072
	Southern	$2,081,220	$12,405,684	$14,038,043	$530,051	$4,112	$1,476	$29,060,585
Fuse Savers	Central	$9,970	$789,937	$854,118	$249,268	$433,473	$2,097,168	$4,433,935
	Metro	$7,557	$561,915	$507,742	$160,801	$298,329	$1,889,794	$3,426,138
	Palisades	$7,468	$522,454	$577,113	$127,207	$656,533	$2,059,075	$3,949,850
	Southern	$9,792	$859,014	$578,217	$245,990	$714,570	$1,623,412	$4,030,996
Total		**$9,600,174**	**$50,035,871**	**$46,056,977**	**$2,277,408**	**$1,824,151**	**$7,708,933**	**$117,802,488**

Table 16 – Contingency Reconfiguration Forecasted Costs as of September 30, 2022 examines the forecast as of the end of the third quarter of 2022 for each Division's Fuse Saver scope compared to the total actual costs incurred through the end of the third quarter of 2022.

Table 16 – Contingency Reconfiguration Forecasted Costs as of September 30, 2022

Scope & Division		Total to Date	Forecast	Remaining Forecast	% of Actuals to Forecast
Reclosers	Central	$25,612,764	$25,612,764	-	100%
	Metro	$24,436,149	$24,436,149	-	100%
	Palisades	$22,852,072	$22,852,072	-	100%
	Southern	$29,060,585	$29,060,585	-	100%
Fuse Savers	Central	$4,433,935	$11,479,821	$7,045,886	39%
	Metro	$3,426,138	$12,879,102	$9,452,964	27%
	Palisades	$3,949,850	$9,958,265	$6,008,415	40%
	Southern	$4,030,996	$11,337,080	$7,306,084	36%
Total		**$110,093,555**	**$147,615,838**	**$29,813,350**	**80%**

As shown in **Table 15**, the overall Contingency Reconfiguration subprogram has spent 80% of its current forecast. With the total forecast as of the end of the third quarter of 2022 increasing $2.0 million from the status as of the end of the prior quarter, driven by increases to the Central Division Fuse Saver scope (increasing approximately $950,000) and the Metro Division Fuse Saver scope (increasing approximately $1.2 million), slightly offset by a forecast decrease to the Southern Division Fuse Saver scope (decreasing approximately $358,000). These forecast variances reflected the trends observed in the actual cost per unit data, which has seen recent increases in testing and installation labor costs as the work has transitioned from more simple installations to more difficult locations including pole replacements at certain locations.

Findings & Observations:

- Progress on the Fuse Savers scope of the subprogram continued to ramp-up following the with 286 devices installed during the third quarter of 2022. This brough the total number of Fuse Savers installed during the Program to 412 out of a current scope of 1,574 units.
- There was no change to the forecasted completion date of the Fuse Saver scope from the prior quarter, with each Division continuing to forecast the final units being installed in December

2023. Based on the current scope, this averages out to approximately 77 units per month (for comparison in the third quarter of 2022, PSE&G averaged 95 units per month).

- The Contingency Reconfiguration subprogram forecast increased approximately $2.0 million during the third quarter of 2022 to $147.6 million, which reflected higher observed costs per unit on the Fuse Savers testing and installation labor. This is above the Stipulation budget of $145.0 million.

C. Grid Modernization – Communication System

The Stipulation identified the Grid Modernization – Communication System subprogram to include up to $72 million invested in installing a private wireless communications network to eliminate the use of dedicated phone lines for remote communication for both PSE&G and customer equipment. The overall network will provide coverage using both wireless and fiber technologies to all switching devices on the PSE&G system. The primary scopes within the Grid Modernization – Communication System include installation of the wireless network, fiber installations at selected stations, fiber cutovers at selected station with existing fiber to the PSE&G fiber network, and retrofitting existing reclosers and RTUs with updated routers. A summary of the status of these primary scopes of work as of the end of the third quarter of 2022 is as follows:

- Wireless network: placed in-service as of December 16, 2021; remaining work involves providing radios to support the installation of Fuse Savers in the Contingency Reconfiguration subprogram.
- Fiber installations and cutovers: 29 out of 34 fiber installation projects completed and 12 out of 12 fiber cutover projects completed.
- Retrofitting existing reclosers: completed as of the fourth quarter of 2021 with a total of 2,318 retrofit reclosers installed.
- Retrofitting RTUs: 218 substation retrofits completed (48 during the third quarter of 2022) out of a total scope of 218 substations.

As previously reported, the fiber scope includes installing fiber to electric substations and electric operations centers, in addition to cutting over stations with existing fiber service to the PSE&G fiber network. PSE&G preliminarily identified 41 installation projects and 12 cutovers for the subprogram, with three of 41 installation projects were previously removed due to the scheduled elimination of the targeted substations or the intended redundancy benefits not achievable after site review. During the second quarter of 2022, PSE&G assessed the remaining budget for the fiber scope and determined it would remove four additional projects from the planned list due to budgetary constraints (in addition to one of the removed stations, Waverly, having the IP fiber installation included as part of the Electric Station Flood Mitigation project at the substation). The list of currently approved fiber installation and cutover projects is presented in **Table 17 – Fiber Projects by Division as of September 30, 2022**.

Table 17 – Fiber Projects by Division as of September 30, 2022

Division	Fiber Installation*	Fiber Cutover*
Central	Cranford; Elizabeth Sub HQ; Rahway; Hadley Road HQ; Roselle; Central HQ; Carteret; Edison; Keasby; Mechanic Street; First Street	Elizabeth; Henry Street

Metro	East Orange; Metro HQ; Bloomfield; Central Avenue; Haldeon; Irvington; Irvington Sub HQ; Montclair; South Orange; Norfolk Street	-
Palisades	Bergen Point; Hackensack Sub HQ; Fort Lee; Harrison; Ridgewood; West New York; Palisades HQ; Culver Avenue; Morgan Street	Tonnelle Avenue; Spring Valley Road; Union City; Fairview; Polk Street; West Orange
Southern	Southern HQ; Princeton; Chauncey Street; Bordentown	Delair; East Riverton; Riverside; Mount Holly
Total	***34 projects***	***12 projects***
**-Projects underlined have been placed in-service.*		

During the third quarter of 2022 two additional fiber installation projects (Montclair, Palisades HQ) and the final fiber cutover project (West Orange) were placed in-service. Thus, the total fiber projects in-service as of the end of the third quarter of 2022 was 29 for the fiber installation projects and 12 for the fiber cutover projects. **Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2022** provides a summary of the status of the fiber installation and cutover projects within the subprogram as of the end of the third quarter of 2022 with the projects in italics representing those placed in-service.

Table 18 – ES 2 Program Fiber Projects Status as of September 30, 2022

Project Name	Q3 2022 Status
Fiber Installation Projects	
Bergen Point	*In-Service (Q1 2021)*
Bloomfield	Township permit received; OP engineering complete; OP construction complete; IP power installation started
Bordentown	*In-Service (Q3 2021)*
Carteret	Railroad permit secured; Division scheduled overhead work for Q4
Central Ave	*In-Service (Q3 2021)*
Central HQ	*In-Service (Q1 2022)*
Chauncey Street	*In-Service (Q3 2021)*
Cranford	*In-Service (Q4 2020)*
Culver Ave	*In-Service (Q1 2022)*
East Orange	*In-Service (Q1 2021)*
Edison	Conduit work complete; OP run completion dependent on railroad permits
Elizabeth Sub HQ	*In-Service (Q1 2021)*
First Street	*In-Service (Q3 2021)*
Fort Lee	*In-Service (Q1 2022)*
Hackensack Sub HQ	*In-Service (Q4 2020)*
Hadley Rd HQ	*In-Service (Q1 2022)*
Haledon	*In-Service (Q1 2022)*
Harrison	*In-Service (Q3 2021)*
Irvington	*In-Service (Q4 2021)*
Irvington Sub HQ	*In-Service (Q4 2021)*
Keasbey	OP work complete; TFI rack installed
Mechanic Street	OP railroad crossing work complete; TFI rack installed
Metro HQ	*In-Service (Q1 2021)*
Montclair	*In-Service (Q3 2022)*
Morgan Street	*In-Service (Q4 2021)*
Norfolk St	*In-Service (Q3 2021)*
Palisades HQ	*In-Service (Q3 2022)*
Princeton	*In-Service (Q3 2021)*
Rahway	*In-Service (Q1 2021)*

Project Name	Q3 2022 Status
Ridgewood	*In-Service (Q1 2022)*
Roselle	*In-Service (Q2 2021)*
So Orange	*In-Service (Q3 2021)*
Southern HQ	*In-Service (Q4 2020)*
West New York	*In-Service (Q1 2022)*
Fiber Cutover Projects	
Delair	*In-Service (Q4 2020)*
East Riverton	*In-Service (Q4 2020)*
Elizabeth	*In-Service (Q1 2021)*
Fairview	*In-Service (Q1 2022)*
Henry St	*In-Service (Q3 2021)*
Mount Holly	*In-Service (Q4 2020)*
Polk Street	*In-Service (Q1 2022)*
Riverside	*In-Service (Q4 2020)*
Spring Valley Rd	*In-Service (Q1 2021)*
Tonnelle Ave	*In-Service (Q4 2020)*
Union City	*In-Service (Q1 2021)*
West Orange	*In-Service (Q3 2022)*
Substation Remote Terminal Unit (RTU) Cutovers	
Scope: 218 units	218 cutovers completed

The Grid Modernization – Communication System subprogram costs by major period through the end of the third quarter of 2022 are presented in **Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of September 30, 2022**, while **Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of September 30, 2022** provides the current forecasts as of the end of the second quarter of 2022 compared to the actual costs.

Table 19 – ES 2 Grid Modernization – Communication System Actual Costs as of September 30, 2022

Scope & Division		2019	2020	2021	Q1 2022	Q2 2022	Q3 2022	Total to Date
		Actuals						
Retrofit Reclosers	Central	$0	$884,278	$3,304,797	$215,275	$186,505	$359,309	$4,950,163
	Metro	$0	$818,620	$2,362,797	$135,374	$192,271	$315,543	$3,824,588
	Palisades	$0	$825,174	$3,115,474	$186,059	$184,718	$349,531	$4,660,956
	Southern	$0	$929,058	$3,862,816	$194,826	$193,249	$292,884	$5,472,833
Fiber	Central	$1,691	$2,418,851	$5,973,655	$1,581,263	$681,857	$446,818	$11,104,134
	Metro	$1,457	$1,866,697	$3,086,096	$1,576,328	$347,002	$245,110	$7,122,690
	Palisades	$1,582	$2,046,762	$3,603,134	$656,307	$93,875	$213,474	$6,615,134
	Southern	$4,731	$910,483	$2,466,477	$96,721	$33,229	$24,153	$3,535,794
	Cutovers*	$0	$876,502	$607,056	$851,293	$8,735	$462,707	$2,311,756
Wireless Network		$74,306	$6,035,441	$1,282,986	$61,558	$99,655	$39,482	$7,593,428
Bulk Purchase**		$0	$1,524,874	($520,766)	$641,029	$283,929	$642,690	$2,571,756
Total		**$83,767**	**$19,136,741**	**$29,144,503**	**$6,196,033**	**$3,225,559**	**$3,391,702**	**$61,178,303**

**-Includes fiber communication cutovers and substation RTU cutovers (the latter of which began having spend in Q1 2021).*
***-The Bulk Purchase account is used for the purchase of bulk equipment, which is the then assigned to a specific Division when the equipment is released with a credit back to the Bulk Purchase account. Thus, this account is forecasted to have a $0 balance at the end of the ES 2 Program.*

Table 20 – ES 2 Grid Modernization – Communication System Forecasts as of September 30, 2022

Scope & Division		Total to Date *Actuals*	Total Forecast	% of Actuals to Forecast
Retrofit Reclosers	Central	$4,950,163	$6,684,144	74%
	Metro	$3,824,588	$5,539,747	69%
	Palisades	$4,660,956	$6,373,177	73%
	Southern	$5,472,833	$7,258,179	75%
Fiber	Central	$11,104,134	$11,482,676	97%
	Metro	$7,122,690	$7,397,935	96%
	Palisades	$6,615,134	$6,680,329	99%
	Southern	$3,535,794	$3,458,757	102%
	Cutovers*	$1,415,071	$1,415,071	100%
Wireless Network		$7,593,428	$7,967,538	95%
Bulk Purchase**		$2,571,756	$0	-
Total		**$61,178,303**	**$66,564,461**	**92%**

As shown in **Table 19**, actual costs incurred in the third quarter of 2022 were close to the spend incurred in the second quarter of 2022 and continues to reflect the winding down of the fiber scope and the efforts on the retrofit recloser scope, which was completed during this quarter. The forecasts shown in **Table 20** remained relatively unchanged from the status as of the end of the second quarter of 2022, with an overall forecast increase of approximately $285,000 (or a 0.4% increase).

Findings & Observations:

- The retrofit substation RTU scope completed 48 substations in the third quarter of 2022, bringing the total to 218 substations completed, which also completes this scope of work ahead of forecast.
- The twelfth and final fiber cutover project was completed during the third quarter of 2022 as were two additional fiber projects, bringing the fiber project total to 29 out of 34 currently planned projects. As of the end of the third quarter of 2022, the fiber scope still is expected to be completed by the end of 2022.
- The forecast for the Grid Modernization – Communication system subprogram continued to remain relatively unchanged from the status as of the prior quarter, with an overall forecast increase of approximately $285K (or a 0.4% increase) to $66.6 million.

D. Grid Modernization – ADMS

The Grid Modernization – ADMS scope is split between three primary sections: DMS/DERMS, the OMS, and ADMS platform upgrades. The scope for each primary component of the Grid Modernization – ADMS subprogram and notable activities conducted during the third quarter of 2022 are presented as follows:

DMS/DERMS

- Scope: Provide software and associated services to deploy a Smart Network in order to meet a subset of the ES 2 Program's objectives and use cases.
- Q3 2022 Activities:
    - Completed loading updated model.

- Completed Sprint 21.
- Completed and reviewed Development Testing Plan.
- Completed review of module variance list.

- Forecasted Completion as of the end of the third quarter of 2022: 12/19/2022 (unchanged from the prior quarter).

OMS

- Scope: Provide a single user interface for more efficient management of trouble orders and analysis of outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data through an integrated OMS, system interfaces, and geographic view of all integrated outage data and damage locations. OMS will include tolls for dynamic visualization supporting incident management, damage location identification, dashboards, and the as-operated real-time view of PSE&G's network model. Field personnel also will have access to many of these tools as it relates to the incident(s) assigned to them via the Compass mobile crew application. 10 years' worth of existing OMS data will be migrated into the new system as well.
- Q3 2022 Activities:
  - Initial scope of conversion data completed, including 10 years of data.
  - Completed team onsite visit at Edison Training Center.
  - Approved interface end-to-end design by SAP and Mulesoft.
  - Completed PowerBI environment test report.
  - Validated and completed firewalls for QAS environments.
  - Completed initial QAS Compass integrations.
  - Completed QAS build/configuration.
  - Prepared for QAS system integration testing, plan/cases, approvals/prep, and staging.
- Forecasted Completion as of the end of the third quarter of 2022: 6/15/2023 (slipped 46 days from the prior quarter, driven by Platform availability to configure the system, which also contributed to the split from one production release to two production releases).

ADMS Platform

- Scope: Replace, enhance, and expand the existing Distribution Supervisory Control and Data acquisition (DSCADA) platform elements inclusive of infrastructure components (servers and workstations) and applications (Monarch, Spectra, and Integra) to create an integrated ADMS platform.
- Q3 2022 Activities:
  - Migrated remaining QAS to Edison Legacy Production.
  - Completed discussions for environment management alignment between OMS and Platform.

- Completed meeting with Geographic Information System (GIS) teams on testing plans for EMap and OSI Maestro.
- Completed decommissioning of legacy ADMS infrastructure at Edison.
- Completed operating system patching and forwarded to Open Systems International Inc. (OSI) for application patching.

- Actual In-Service Date: 1/28/2022.

The Grid Modernization – ADMS subprogram costs through the end of the third quarter of 2022 are presented in **Table 21 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2022**.

Table 21 – ES 2 Grid Modernization – ADMS Costs as of September 30, 2022

Scope	Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
	Actuals						*Forecast*	
OMS	$33,891	$8,375,966	$7,140,445	$2,010,781	$6,360,390	$2,267,867	$5,344,016	$12,541,708
DMS/ DERMS	$1,498	$1,858,969	$1,185,863	$510,094	$676,889	$581,013	$1,145,585	$1,813,572
Platform	$824	$1,998,769	$1,411,403	$646,982	$934,541	$310,094	$208,468	$246,712
ADMS Hardware	-	$4,213,920	$116,732	$30,020	$259,042	$35,462	-	-
Total ADMS	**$36,213**	**$16,447,624**	**$9,854,442**	**$3,197,877**	**$8,230,861**	**$3,194,435**	**$6,698,069**	**$13,247,939**

Scope	Actuals to Date	Forecast	% of Actuals to Forecast
OMS	$26,189,340	$44,075,064	59%
DMS/DERMS	$4,814,325	$6,627,897	73%
Platform	$5,302,613	$5,549,325	96%
ADMS Hardware	$4,655,175	$4,655,175	100%
Total ADMS	**$40,961,453**	**$60,907,462**	**67%**

The cost forecast for the Grid Modernization – ADMS subprogram increased by approximately $7.4 million from the status as of the end of the prior quarter. This increase was driven by the schedule extension on the OMS scope and adjustments to the planned production releases, which changed from one original release planned for April 2023 to two releases planned for May and November 2023. This split was intended to allow all core/mission critical functionalities to be released in May 2023 ahead of the storm season moratorium, with the remaining enhancements included in the November 2023 release after the moratorium period.

Findings & Observations:

- The first of three primary ADMS components (the ADMS Platform) was placed in-service during the first quarter of 2022, with work in the third quarter of 2022 involving decommissioning of legacy ADMS infrastructure and operating system patching. The remaining DMS/DERMS and OMS scopes are currently be forecasted to be placed in-service in December 2022 and June 2023, respectively.
- During the third quarter of 2022, the subprogram forecast increased by approximately $7.4 million to $60.9 million. This increase was driven by an updated OMS schedule and was

comprised of approximately $4.1 million related to PSE&G labor and $3.3 million for staff augmentation costs.

- At PSE&G's prompting, its software vendor added additional resources with more technical experience than previous deployments. This is expected to improve the performance of the group, particularly as more testing efforts continue.

E. Electric Stipulated Base

The Stipulation identified that the electric portion of the Stipulated Base include $100 million in investments at PSE&G's discretion towards electric OP-HDS and/or electric stations life cycle subprograms described in the original ES 2 filing.[1] In accordance with what the Stipulation provides, PSE&G plans to fund some of the life cycle station upgrades from the electric program accelerated investment, subject to funds available, after all Electric Station Flood Mitigation projects are funded at their final costs.

PSE&G commenced the OP-HDS in July 2022, but with the current forecasts for the life cycle station upgrade projects consuming the entire Stipulated Base funding ($100.6 million forecast compared to the $100.0 million Electric Stipulated Base budget), this work is presently being executed outside of the ES 2 Program. If the forecasts for the substation projects lower and additional funding becomes available, PSE&G may include some of the OP-HDS through the Program funding. The IM intends to continue to follow the status of this work, but will only report on it should PSE&G include these costs under the ES 2 Program.

As reported in the IM 2020 Second Quarter Report, the initial four stations PSE&G selected for life cycle station upgrades went before the URB in June 2020 for Study level estimate approval and received approval for full funding. In the second quarter of 2021 a fifth station, State Street, was approved by the URB for its outside plant scope to be transferred from the related Electric Station Flood Mitigation project to the life cycle scope. The five life cycle station upgrade projects and their current estimate compared to the actuals to date are provided in **Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022**.

Table 22 – ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
1. Hamilton	Definitive	$16,800,000	-	$16,800,000	$12,901,001	77%	10/24/2022 (↓ +19)
2. Paramus	Definitive	$21,400,000	-	$21,400,000	$16,857,336	79%	11/9/2022 (↓ +6)
3. Plainfield	Definitive	$22,600,000	-	$22,600,000	$17,051,905	76%	12/28/2022 (↓ +30)

[1] As noted in the Stipulation, the electric life cycle upgrades are part of the electric Stipulated Base to be recovered in the Company's next base rate case provided the investments are found to be prudent. The Stipulation also notes that should the 16 stations that comprise the Electric Station Flood Mitigation subprogram be completed for under the $389 million allocated for that subprogram, PSE&G may reallocate such unused funds to stations identified in the life cycle station upgrade portion of PSE&G's petition for accelerated recovery.

Project	Estimate Level	Base	Risk & Contingency*	Total	Actuals to Date	% of Actuals to Estimate	Forecasted In-Service Date**
4. Woodbury	Definitive	$18,100,000	-	$18,100,000	$10,570,960	58%	6/27/2023 (↓ +179)
5. State Street (OP)	Study	$19,700,000	-	$19,700,000	$1,691,533	9%	4/21/2023 (↓ +123)

**-As discussed in the IM 2022 First Quarter Report, during the first quarter of 2022, PSE&G made the decision to hold risk and contingency at the subprogram level.*

***-Reflects the in-service date of the last major asset (e.g. switchgear), certain activities may take place after this date to support the final in-service date (i.e. when all customers are cutover).*

(↑)-*Indicates the forecasted in-service date advanced from the prior quarter.*

(↓)-*Indicates the forecasted in-service date slipped from the prior quarter.*

As shown in **Table 22**, all five life cycle station upgrade projects saw the forecasted in-service date slip from the status as of the end of the prior quarter. Overall, these shifts in forecasted in-service dates were relatively minor in two of the five substations, driven by actual project conditions. On Plainfield and Woodbury, the forecasted in-service date slip was the result of updated delivery switchgear delivery timelines provided by the vendor, while on State Street (OP) the in-service date slip was the result of a change in the manhole and conduit design due to an existing obstruction that will result in the manhole and conduit system not being energized until the second circuit is cutover (rather than with the first circuit as had originally been the plan). Additional details on each of these life cycle station upgrade projects is provided in the individual subsections that follow.

Similar to the Electric Station Flood Mitigation subprogram, the life cycle station upgrade projects within the Electric Stipulated Base experienced some delays to the forecasted delivery dates of the major equipment. The status of the major equipment deliveries for the Electric Stipulated Base projects is presented in **Table 23 – Electric Station Flood Mitigation Major Switchgear Deliveries as of September 30, 2022**.

Table 23 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022

Station	Description	Delivery Status as of Q2 2022	Delivery Status as of Q3 2022
1. Hamilton	4kV switchgear	***4/5/2022***	***4/5/2022***
2. Paramus	4kV switchgear	***5/31/2022***	***5/31/2022***
	4kV cont. switchgear	***7/8/2021***	***7/8/2021***
3. Plainfield	4kV switchgear	8/26/2022	***9/15/2022***
4. Woodbury	4kV switchgear	7/20/2022	***9/21/2022***
Note: bold/italicized dates indicate actual delivery dates.			

As shown in **Table 23**, the major equipment deliveries for Plainfield and Woodbury were both completed in the third quarter of 2022, although both still experienced some slippage from the status at the end of the prior quarter that impacted the forecasted in-service dates for both projects.

Findings & Observations:

- Construction continued on the Hamilton, Paramus, Plainfield, and Woodbury projects, while engineering continued to advance on the State Street OP project (which continues to be expected to commence construction in the fourth quarter of 2022).

- The forecasted in-service dates for the five life cycle station upgrade projects as of the end of the third quarter of 2022 shows three of the five projects expected to go in-service before the end of 2022 (Hamilton, Paramus, and Plainfield). The forecasted in-service date for Woodbury shifted from December 2022 to June 2023 due to switchgear delivery delays (which also impacted the Plainfield project, but to a lesser degree), while the State Street OP forecasted in-service date shifted from December 2022 to April 2023 due to manhole and conduit redesigns, which resulted in the energization of the manhole and conduit system being tied to the second circuit cutover rather than the first circuit cutover (which is planned for December 2022).
- The cost forecasts for the five life cycle upgrade projects collectively increased by approximately $1.5 million (or 1.5%) from the status as of the end of the prior quarter to a total forecast of $100.6 million as of the end of the third quarter of 2022. This increase was largely attributed to minor cost impacts across the projects stemming from actual conditions (e.g. Hamilton and Paramus both had $0.2 million increases attributed to more Relay tech hours than forecasted, Plainfield had a $0.2 increase due to unforeseen underground obstructions, etc.).

1. Hamilton

During the third quarter of 2022, $2,537,609 was spent on the Hamilton project against a forecast of approximately $2.4 million. This brought total spend on the project to approximately $12.9 million through the end of the third quarter of 2022. The forecasted in-service date for the Hamilton project slipped 19 days from the status as of the end of the prior quarter to October 24, 2022.

Notable activities performed on the Hamilton during the third quarter of 2022 included:

- Installation of new OP duct banks and manholes;
- Continued electrical construction, including cable pulls and terminations; and,
- Completion of the Switchgear commissioning.

The actual spend by quarter for Hamilton as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$0	$362,372	$3,141,022	$3,770,758	$3,089,239	$2,537,609	$1,644,117	$2,930,830

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$16,800,000	$12,901,001	77%
Forecast	$17,475,949		74%

2. Paramus

During the third quarter of 2022, $2,053,294 was spent on the Paramus project against a forecast of approximately $2.1 million. This brought total spend on the project to approximately $16.9 million through the end of the third quarter of 2022. The forecasted in-service date for the Paramus project slipped six days from the status as of the end of the prior quarter to November 9, 2022.

Notable activities conducted during the third quarter of 2022 on the Paramus project included:

- Continued setting up/assembly of the new 4kV switchgear;
- Continued cable pulls to the new 4kV switchgear;
- Assembly of the new 4kV regulators;
- Commencement of switchgear commissioning; and,
- Start of 4kV bus support installation.

The actual spend by quarter for Paramus as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$840,200	$7,068,765	$952,513	$5,942,564	$2,053,294	$1,332,615	$3,589,704

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$21,400,000	$16,857,336	79%
Forecast	$21,779,654		77%

3. Plainfield

During the third quarter of 2022, $8,420,160 was spent on the Plainfield project against a forecast of approximately $6.9 million. This brought total spend on the project to approximately $17.1 million through the end of the third quarter of 2022. The variance in forecasted to actual spend in the third quarter of 2022 was largely attributed to the invoice for the switchgear being processed earlier than anticipated (last day of the month, which had not been communicated to the cost engineer in advance).

The forecasted in-service date for the Plainfield project as of slipped 30 days from the status as of the prior quarter to December 28, 2022. This slip in the forecasted in-service date was driven by delays associated with the delivery of the switchgear (which slipped from late July 2022 to mid-September 2022).

Notable activities conducted on the Plainfield project during the third quarter of 2022 included:

- Installation of the switchgear platform;
- Commencement of electrical construction, including cable pulls and installing regulators;
- Delivery of the switchgear/setting the switchgear on foundations; and,
- Commencement of switchgear commissioning.

The actual spend by quarter for Plainfield as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$682,325	$3,584,101	$1,682,480	$2,682,840	$8,420,160	$2,403,443	$3,759,251

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$22,600,000	$17,051,906	76%
Forecast	$23,214,599		73%

4. Woodbury

During the third quarter of 2022, $5,168,609 was spent on the Woodbury project against a forecast of approximately $7.0 million. This brought the total spend on the project to approximately $10.6 million through the end of the third quarter 2022. The variance in forecasted to actual spend in the third quarter of 2022 was largely attributed to the switchgear delivery shifting out to September 2022 (with the delivery shift occurring after the forecast was locked).

The forecasted in-service date for the Woodbury project slipped 179 days from the status as of the end of the prior quarter to June 27, 2023. The in-service date shift was driven by delays to the switchgear and feeder rows deliveries and an expanded duration for commissioning.

Notable activities conducted on the Woodbury project during the third quarter of 2022 included:

- Start of electrical construction; and,
- Switchgear delivered and set on foundation;

The actual spend by quarter for Woodbury as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$551,165	$1,613,823	$1,460,525	$1,776,838	$5,168,609	$1,875,626	$5,653,414

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$18,100,000	$10,570,960	58%
Forecast	$18,100,000		58%

5. State Street (Outside Plant)

During the third quarter of 2022, $983,856 was spent on the State Street (OP) project against a forecast of approximately $1.7 million. The variance in forecasted to actual spend for the third quarter of 2022 was predominantly the result of overestimated subcontractor services (traffic control and vacuum truck support) and the Division not being able to start overhead work as planned for circuit 4005, which also relates to the shift in forecasted in-service date discussed below.

As of the end of the third quarter of 2022, the forecasted in-service date for the State Street OP project slipped 123 days from the status as of the prior quarter to April 21, 2023. This forecasted in-service date shift was driven by manhole and conduit exits from the substation that required redesigns due to existing underground obstructions. As a result of this redesign, the circuit 4005 (first circuit to be placed in-service) is being placed on its own manhole and conduit system and the energization will follow the second circuit being cutover in 2023.

Notable activities conducted during the third quarter of 2022 included the approval and receipt of the test pits permit and the commencement and completion of the test pits.

The actual spend by quarter for State Street (OP) as compared to the current forecast and URB approved estimate is provided below.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023-2024
Actuals						*Forecast*	
$0	$0	$211,247	$395,903	$100,527	$983,856	$1,797,246	$16,523,810

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,700,000	$1,691,534	9%
Forecast	$20,012,589		8%

F. Gas M&R Station Upgrades

During the third quarter of 2022, PSE&G submitted updated estimates for the Camden and East Rutherford Gas M&R projects, with both advancing to a Definitive level estimate. **Table 24 – ES 2 Gas M&R Summary Status as of September 30, 2022** below provides these newly approved estimates and the other current estimates for each project within the Gas M&R subprogram, along with the actuals to date and forecasted in-service dates.

Table 24 – ES 2 Gas M&R Summary Status as of September 30, 2022

Project	Estimate Level	Base	Risk & Contingency	Total Estimate	Actuals	% of Actuals to Estimate	Forecasted In-Service
1. Camden	Definitive	$21,600,000	$200,000	$21,800,000	$26,707,869	123%	Dec 2022
2. Central*	Conceptual	$31,400,000	$5,500,000	$36,900,000	$23,653,126	64%	Nov 2023
3. East Rutherford	Definitive	$24,100,000	$1,900,000	$26,000,000	$14,604,488	56%	Dec 2022
4. Mount Laurel*	Conceptual	$12,700,000	$3,100,000	$15,800,000	$1,680,782	11%	Nov 2023
5. Paramus*	Study	$11,500,000	$8,400,000	$19,900,000	$1,317,612	7%	Dec 2023
6. Westampton	Definitive	$8,400,000	$-	$8,400,000	$8,413,061	100%	*Oct 2021 (actual)*
Subprogram Total		**$109,700,000**	**$19,100,000**	**$128,800,000**	**$76,376,937**	**59%**	**Dec 2023**

**-Included in the Stipulated Base.*
(↑)-Indicates the forecasted in-service date advanced from the prior quarter.
(↓)-Indicates the forecasted in-service date slipped from the prior quarter.

The updated estimates for Camden and East Rutherford collectively resulted in no change to the overall subprogram estimate as the $5.5 million increase to the base estimate was offset by releasing $5.5 million in R&C funds. Note also that while the current actuals for Camden exceed the updated estimate, this is due to the actuals still including costs associated with the liquid propane air (LPA) scope that was removed from the ES 2 project, a cost adjustment is expected to be recorded to account for this in the fourth quarter of 2022. Details of the individual estimate changes are discussed within the individual project discussions that follow.

Relative to the forecasted in-service dates shown in **Table 24**, as of the end of the third quarter of 2022, the forecasted in-service dates for the remaining Gas M&R projects remained essentially unchanged from the status as of the end of the prior quarter (Camden and East Rutherford both saw forecasted in-service

date shifts of five days or less, but both remain forecasted to go in-service in December 2022). As previously reported, the Westampton project was placed in-service as of October 22, 2021.

Findings & Observations:

- The six projects that comprise the Gas M&R subprogram continues to advance at various stages of development reflecting the targeted delivery schedule. During the third quarter of 2022, construction continued to advance on the Camden, Central, and East Rutherford projects, while the Mount Laurel and Paramus projects continued pre-construction activities including Mount Laurel preparing the civil construction package and Paramus addressing comments from the zoning board. The Westampton project was previously put in-service in October 2021, while punch list items and site restoration activities continued in the third quarter of 2022.
- There were no significant changes to the forecasted in-service dates of the Gas M&R projects during the third quarter of 2022. The next projects to be completed are the Camden and East Rutherford projects, which are forecasted to be placed in-service in December 2022. The final projects, Central, Mount Laurel, and Paramus each continue to be forecasted for November-December 2023 in-service dates.
- As of the end of the third quarter of 2022, the overall subprogram forecast increased approximately $6.0 million from the status as of the end of the prior quarter. This forecast increase is predominantly within the Camden (forecast increased approximately $3.1 million) and East Rutherford (forecast increased approximately $2.4 million) projects, where the forecast increase aligned with an updated estimate on these projects, which reflected the current status of design, procurement, and construction plans and activities.
- The IM has found nothing to date that would jeopardize the subprogram being completed on time, however, the current forecast of $110.3 million exceeds the Stipulation budget of $101.0 million and with the latest forecast increase is trending upward.

1. Camden

During the third quarter of 2022, $13,240,520 was spent on the Camden project compared to a forecast of approximately $17.3 million, which brought the total spend to approximately $26.7 million. The variance in forecasted to actual spend in the third quarter of 2022 was driven by permit delays that delayed mechanical construction activities and shipping delays for valves and switchgears. Despite these delays, the forecasted in-service date for the Camden project slipped only three days from the status as of the end of the prior quarter to December 19, 2022.

Notable activities on the Camden project during the third quarter of 2022 included:

- Completed excavations and pouring for building footings and foundations;
- Began excavation in street for distribution tie-ins;
- Continued pipe fabrication;
- Began steel erection for the mix and control buildings;
- Began installing outlet piping within the M&R station; and,
- Continued electrical and plumbing rough in.

The actual spend by quarter for Camden as compared to the current forecast and URB approved estimate is provided below. Late in the third quarter of 2022, PSE&G advanced the Camden project estimate to the

Definitive stage, which saw the overall estimate remain at $21.8 million after the allocation of R&C. The specific changes from the prior estimate are as follows:

- Change in pressure control valves ($1.3 million);
- Design refinement – predominantly impacts from unknown underground conditions and electrical requests for information (RFIs) ($0.8 million);
- Escalated material costs and changes between issued for bid (IFB) and IFC drawings, primarily valves, platforms, and electrical materials ($0.7 million);
- Pipeline agreement with Transco required additional modifications to be incorporated ($0.3 million); and,
- Transfer of R&C to base (-$3.1 million).

While the current estimate of $21.8 million and the current forecast of $21.6 million have both been exceeded by the actual costs to date on the Camden project, these actual costs include costs related with the LPA scope of the Camden project that PSE&G is removing from the ES 2 Program and will result in adjusted actual costs for the ES 2 Camden project in the fourth quarter of 2022.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$13,326	$859,350	$2,147,696	$2,791,701	$7,655,276	$13,240,520	($6,903,540)	$1,795,670

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$21,800,000	$26,707,870*	123%
Forecast	$21,600,000		124%
**-Approximately $9.9 million of actuals will be journaled out in October 2022 to reflect the split of the LPA scope of the Camden project that removes the LPA scope from the ES 2 project.*			

2. Central

During the third quarter of 2022, $4,607,003 was spent on the Central project compared to a forecast of approximately $4.2 million, which brought the total spend to approximately $23.7 million. The forecasted in-service date for the Central project as of the end of the third quarter of 2022 remains at November 30, 2023, unchanged from the status as of the end of the prior quarter.

Notable activities on the Central project during the third quarter of 2022 included:

- Completed erection of the regulator and heater buildings;
- Heat exchangers/flow control building erection complete and fit out initiated;
- Began erecting steel skin for the control building;
- Continued fit out of SCADA building;
- Continued pipe fabrication; and
- Continued electrical and plumbing rough in.

The actual spend by quarter for Central as compared to the current forecast and URB approved estimate is provided below. The forecast of $31.4 million for the Central project remains virtually unchanged from

the status as of the end of the prior quarter and excludes costs associated with the LPA scope that was removed from the Program.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$6,869	$670,582	$4,226,277	$7,112,617	$7,029,778	$4,607,003	$3,740,040	$4,066,834

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$36,900,000	$23,653,126	64%
Forecast	$31,400,000		75%

3. East Rutherford

During the third quarter of 2022, $6,324,865 was spent on the East Rutherford project compared to a forecast of approximately $11.1 million, which brought the total spend to approximately $14.6 million. The variance in forecasted to actual spend during the third quarter of 2022 was driven by supply chain/material delivery delays and a delay in finalizing the Transco pipeline agreement addendum that pushed a forecasted payment. The forecasted in-service date for the East Rutherford project as of the end of the third quarter of 2022 slipped five days from the status as of the end of the prior quarter to December 21, 2022.

Notable activities on the East Rutherford project during the third quarter of 2022 included:

- Drained and removed heaters;
- Completed pile driving;
- Foundation work for regulator and control buildings;
- Continued pipe fabrication;
- Continued electrical rough in;
- Received and set the control SCADA building; and,
- Began excavating for yard piping and piping supports.

The actual spend by quarter for East Rutherford as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. Late in the third quarter of 2022, PSE&G advanced the East Rutherford project estimate to the Definitive stage, which resulted in no change to the prior estimate of $26.0 million after allocation of R&C. The specific changes from the prior estimate are as follows:

- Design refinement of IFCs through submittals and RFIs derived from unforeseen field conditions, construction sequencing, and design revision including impacts to electrical, mechanical, and civil work ($1.4 million);
- Higher levels of asbestos containing materials and PCB pipe contamination discovered during demolition and change to dewatering strategy ($0.6 million);
- New requirement stemming from a new requirement in the executed pipeline agreement with Transco for daily supervision to oversee activities on Tansco property (East Rutherford site owned by Transco) ($0.4 million);
- Transfer of R&C to base (-$2.4 million).

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$9,010	$521,865	$1,783,623	$1,551,290	$4,413,835	$6,324,865	$9,010,011	$485,502

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$26,000,000	$14,604,488	64%
Forecast	$24,100,000		61%

4. Mount Laurel

During the third quarter of 2022, $607,409 was spent on the Mount Laurel project compared to a forecast of approximately $760,000, which brought the total spend to approximately $1.7 million. The forecasted in-service date for the Mount Laurel project as of the end of the third quarter of 2022 remained unchanged from the status as of the end of the prior quarter at November 30, 2023.

Notable activities on the Mount Laurel project during the third quarter of 2022 included:

- Prepared and issued the civil construction contract; and,
- Finalized interconnection agreement with Transco.

Construction activities on Mount Laurel are planned to commence in the second quarter of 2023.

The actual spend by quarter for Mount Laurel as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Mount Laurel project remained essentially unchanged from the prior quarter at approximately $12.7 million.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$5,965	$362,167	$527,341	$135,639	$42,260	$607,409	$373,513	$10,645,706

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$15,800,000	$1,680,782	11%
Forecast	$12,700,000		13%

5. Paramus

During the third quarter of 2022, $67,221 was spent on the Paramus project compared to a forecast of approximately $103,000, which brought the total spend to approximately $1.3 million. The forecasted in-service date for the Paramus project as of the end of the third quarter of 2022 remains unchanged from the status as of the end of the prior quarter at December 29, 2023.

Notable activities on the Paramus project during the third quarter of 2022 included:

- Responded to comments from the Paramus Zoning Board; and,
- Received draft IFB drawings and documents, which have resulted in no scope changes.

Construction activities on the Paramus project is planned to commence in the second quarter of 2023.

The actual spend by quarter for Paramus as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project. The forecast for the Paramus project as of the end of the third quarter of 2022 increased approximately $500,000 from the prior quarter, driven by additional A/E support required and offset by R&C funds.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$8,842	$462,452	$568,344	$94,755	$115,998	$67,221	$1,067,026	$9,615,363

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$19,900,000	$1,317,611	7%
Forecast	$12,00,000		11%

6. Westampton

During the third quarter of 2022, $100,140 was spent on the Westampton project compared to a forecast of approximately $242,000, which brought the total spend to approximately $8.4 million. The Westampton was placed in-service as of October 22, 2021, remaining activities include site restoration and final punch list items that continued to be performed in the third quarter of 2022.

During the third quarter of 2022, notable activities on the Westampton project included:

- Continuing to work through punch list items;
- Completed final paving and site restoration.

This effectively concludes the Westampton project, although minor trailing costs are expected in the fourth quarter of 2022.

The actual spend by quarter for Westampton as compared to the current URB approved estimate is provided below along with the forecasted spend through the end of the project.

Q4 2019	2020 Total	2021 Total	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Actuals						*Forecast*	
$8,395	$1,032,670	$6,961,216	$178,124	$132,517	$100,140	$59,323	$0

Estimate & Forecast		Actuals to Date	% of Actuals to Estimate & Forecast
Estimate	$8,400,000	$8,413,062	100%
Forecast	$8,472,385		99%

ENERGY STRONG PROGRAM

INDEPENDENT MONITOR

2022 THIRD QUARTER REPORT

APPENDIX A – DRAFT REPORT COMMENTS AND RESPONSES

NOVEMBER 13, 2023

PEGASUS GLOBAL HOLDINGS, INC. ®

Questions & Comments to the IM 2022 Third Quarter Report Formally Submitted to the IM

ID #	Question/Comment	IM Response	Report Changes
S-INF-1	**Reference Q3 2022 Report, Page 2, Table 1 – ES 2 Subprogram & Stipulated Base Status as of September 30, 2022** Please reconcile why the Energy Strong II program is forecasted to be completed in February 2024 despite the Electric Station Flood Mitigation subprogram being forecasted to be completed in April 2024.	The "Total" row on **Table 1** was incorrectly not updated to reflect the latest schedule update to the Waverly Electric Station Flood Mitigation project that shifted from February to April 2024 during the third quarter of 2022 and represents the final forecasted project for the Program.	**Table 1**
S-INF-2	**Reference Q3 2022 Report, Page 16, Table 10 – Electric Station Flood Mitigation Switchgear Deliveries as of September 30, 2022** Please describe the planned timeline for returning the Kingsland 13kV switchgear, which is being used as the Ridgefield 13kV contingency/temporary switchgear, to be installed on the Kingsland project.	The contingency switchgear on Ridgefield 13kV will be disassembled and delivered to the Kingsland site following the commissioning of the permanent switchgear at the Ridgefield 13kV site. This disassembly at Ridgefield 13kV and delivery to Kingsland is expected to take place during the first quarter of 2023.	**Table 11** (was previously Table 10)
S-INF-3	**Reference Q3 2022 Report, Page 24, Meadow Road Substation Project** With respect to the Meadow Road substation project: a. Please discuss if any Energy Strong II work will be combined with proposed transmission work occurring adjacent to the Meadow Road substation (See PJM TEAC Presentation dated September 5, 2023, Slides 5-6) (link:https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230905/20230905-item-06---pseg-supplemental-projects.ashx). b. The PJM TEAC Presentation notes that PSE&G is proposing to construct a new 230-13kV substation on property adjacent to the existing Meadow Road substation. Please confirm that the scope of the Energy Strong II project still consists of raising and rebuilding the existing Meadow Road substation.	Regarding the Meadow Road project: a. There is no ES 2 project scope combined with the proposed transmission work. b. The ES 2 scope is confirmed as consisting of raising and rebuilding the existing substation.	No changes
S-INF-4	**Reference Q3 2022 Report, Page 31, Contingency Reconfiguration Subprogram** Regarding the Fuse Saver projects within the Contingency Reconfiguration subprogram, please provide additional details about the increases in the actual cost per unit observed since the start of the program.	In the ES 2 filing, PSE&G estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed;*	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices." The construction standard and training were developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average $35,216 and two-phase devices average $48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by: • The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately $10,000 in costs per unit); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in	

ID #	Question/Comment	IM Response	Report Changes
		many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole.	
S-INF-5	**Reference Q3 2022 Report, Page 32, Communication System Subprogram** Regarding the Communication System subprogram projects placed in-service in Q3 2022, please compare the actual costs to the budgeted costs.	For these projects, which consisted of Montclair, Palisades HQ, and West Orange, the budgeted vs. actual costs are presented as follows: • Montclair: budget of $840,000 vs. actual costs of $2,725,350. • Palisades HQ: budget of $255,000 vs. actual costs of $633,296. • West Orange: budget of $50,000 vs. actual costs of approximately $58,000. The cost variances experienced on Montclair and Palisades HQ were largely due to the fact that the estimates were developed at less than 30% confidence via analogous estimates that did not account for differing station field conditions. Originally, PSE&G used a placeholder value for all stations' Inside Plant costs and later refined these values based on the required equipment. The Outside Plant costs were also estimated with lower levels of confidence and were further refined based on the split of Overhead and Underground scope required.	No change
S-INF-6	**Reference Q3 2022 Report, Page 36, Grid Modernization - ADMS Subprogram** Regarding the ADMS project, please provide additional details about the need to incorporate two (2) production releases rather than the originally planned one (1) production release.	The split of OMS implementation into two production releases was intended to go-live with all core/mission critical functionalities in the first release in May 2023 ahead of the start of the "storm season" and remaining enhancements in a second release in fall 2023 after the storm season moratorium. The OMS project ultimately did not meet the May 2023 release date, which resulted in reverting the project to a single production release currently scheduled to go live in December 2023.	**Section III.D.**
S-INF-7	**Reference Q3 2022 Report, Page 44, Camden M&R Station** Regarding the Camden M&R Station project, refer to the statement "Approximately $9.9 million of actuals will be journaled out in October 2022 to reflect the split of	The $18.1 million reduction from the LPA scope removal reflected the entire estimate of the LPA scope while the $9.9 million that will be journaled out of the	No change

ID #	Question/Comment	IM Response	Report Changes
	the LPA scope of the Camden project that removes the LPA scope from the ES 2 project." Please reconcile this with the IM's previous report, which indicated that the removal of the LPA scope would result in a $18.1 million cost reduction to the Camden M&R project (See Q2 2022 Report, Page 48).	ES 2 project actual costs reflects the actual costs incurred on the ES 2 project related to the LPA scope prior to that scope being removed from the Program.	
S-INF-8	**Reference Q3 2022 Report, Page 45, Central M&R Station** Regarding the Central M&R Station project, please clarify if the forecasted cost ($31.4 million) includes the cost of the LPA scope.	The costs associated with the LPA scope were removed from the Central M&R Station project forecast and thus not included in the current $31.4 million forecast.	**Section III.F.2.**
S-INF-9	**Reference Q3 2022 Report, Page 47, Paramus M&R Station** Regarding the Paramus M&R Station project, please provide additional details about the comments received from the Paramus Zoning Board, including any resulting scope changes.	The comments received from the Paramus Zoning Board on the Paramus Gas M&R project have not resulted in any scope changes, but did require among other things: • Improvements are to be completed in accordance with testimony and evidence submitted to the Board. • Building permits are required to be secured, where applicable, prior to conducting any site modifications. • Compliance with the Board Engineer's review memoranda. • Installation of soundproof paneling on the building interior. • Provide the Air Quality Permit from the NJDEP. • Coordinate with Transco for installation of additional security cameras.	**Section III.F.5.**
RCR-IM-1	With reference to page 1 of the Independent Monitor's Draft Third Quarter 2022 Report, please provide an update on the draw down of risk and contingency funds in the Electric Station Flood Mitigation and Gas M&R subprograms.	The changes to R&C on the Electric Station Flood Mitigation and Gas M&R subprograms during the third quarter of 2022 resulted in the R&C balance in the Electric Station Flood Mitigation subprogram decreasing by $12.5 million to $29.3 million (shown as the Placeholder amount in **Table 11)** and in the Gas M&R subprogram by $5.5 million to $19.1 million (shown in **Table 23**). The overall estimates for each of these subprograms remained unchanged as the drawdown in R&C matched an increase in the base estimate for projects that had updated estimates in the quarter (Electric Station Flood Mitigation projects: Clay Street, Meadow Road, Kingsland, Ridgefield 4kV	No change

ID #	Question/Comment	IM Response	Report Changes
		(decreased $100K as part of the project closeout), Waverly, and Woodlynne; and Gas M&R projects: Camden and East Rutherford).	
RCR-IM-2	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the additional subprogram costs associated with the delay in the forecasted completion date for the Electric Station Flood Mitigation subprogram from February 2024 reported in the Second Quarter 2022 Report to April 2024.	The Lakeside project within the Electric Station Flood Mitigation subprogram has incurred approximately $500K in additional costs related to the extended duration ($400K in extra carrying costs for the extended schedule, $100K for construction acceleration due to the switchgear delivery over five months after its purchase order delivery date).	No change
RCR-IM-3	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the additional subprogram costs associated with the delay in the forecasted completion date for the Grid Modernization - ADMS subprogram from December 2022 reported in the Second Quarter 2022 Report to June 2023.	The delay to the ADMS subprogram has contributed to approximately $7.4 million in additional costs to the subprogram (approximately $4.3 million attributed to PSE&G labor, $3.3 million for staff augmentation costs). See also the response to **RCR-IM-8**.	**Section III.D.**
RCR-IM-4	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, Table 1 ES 2 Subprogram & Stipulated Base Status as of September 30, 2022, please identify the source of the $3.6 million increase in the Gas M&R subprogram included in the total subprogram increase of $27.8 million over the stipulation amount of $101 million for this subprogram.	When PSE&G approved this additional funding for the Gas M&R subprogram in the second quarter of 2022, the Base estimate of the six projects within the subprogram totaled $104.2 million, the R&C balances totaled $24.6 million, and the overall subprogram estimate was $128.8 million. This $128.8 million represented a $27.8 million increase over the Stipulation's $101.0 million budget for the subprogram. Of that $27.8 million, $24.6 million was attributed to additional R&C while the remaining $3.2 million was realized in the increased Base estimates of these projects ($104.2 million as of the end of the second quarter of 2022, see Table 25 of the IM's 2022 2nd Quarter Report).	No change
RCR-IM-5	With reference to page 2 of the Independent Monitor's Draft Third Quarter 2022 Report, please indicate whether other supply chain issues in addition to the 4 kV switchgear delivery delays are contributing to the 163 day delay in the forecasted in service date for Lakeside Avenue from September 18, 2023 to February 28, 2024.	There are other supply chain issues from sub-vendors to the switchgear manufacturer that are contributing to this switchgear manufacturing delay, but the current delay to the Lakeside Avenue project is driven by the delay to the switchgear delivery.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-6	With reference to page 4 of the Independent Monitor's Draft Third Quarter 2022 Report, please confirm for the Contingency Reconfiguration program that only 286 fuse saver units were installed during the 2022 Third Quarter, leaving 1,162 units to be installed by December 31, 2023 as part of the Contingency Reconfiguration subprogram.	The IM confirms 286 Fuse Savers were installed during the third quarter of 2022. This also represented effectively the first full quarter of installations of the Fuse Savers, with nearly 70% of the total devices installed to date installed during this quarter. As noted in the Findings & Observations within **Section III.B.**, based on the current scope, this averages out to approximately 77 units per month (for comparison in the third quarter of 2022, PSE&G averaged 95 units per month).	No change
RCR-IM-7	With reference to page 4 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain the discrepancy between the Contingency Reconfiguration program planned scope of 1,574 units compared to planned scope 1,641 fuse saver units reported in the Second Quarter 2022 Report.	PSE&G assesses the actual cost per unit data and adjusts the Program targets on a quarterly basis based on the current data. As the costs per unit of the Fuse Savers has been higher than initially estimated (see also the response to **S-INF-4**), this has resulted in PSE&G lowering the targeted number of units to be installed in the Program in order to maintain the established budget.	**Section III.B.**
RCR-IM-8	With reference to page 5 of the Independent Monitor's Draft Third Quarter 2022 Report, please elaborate on the $7.4 million increase in the Grid Modernization ADMS subprogram budget, involving changes in the Outage Management System from one to two production releases, at an increased cost of $7.4 million, increasing total ADMS subprogram budget from $53.47 million to $60.90 million.	The delay to the ADMS subprogram has contributed to approximately $7.4 million in additional costs to the subprogram (approximately $4.3 million attributed to PSE&G labor, $3.3 million for staff augmentation costs). There were no additional costs associated with the split to two production releases. See also the response to **RCR-IM-3** and **S-INF-6**.	**Section III.D.**
RCR-IM-9	With reference to page 9, Figure 2 -- ES 2 CWIP Balances by Subprogram as of September 30, 2022, please explain the discrepancy between the $99.39 million Q3 2022 subtotal for the ES 2 Electric Station Flood Mitigation, while the preceding paragraph on page 8 discussing construction work-in-progress highlights CWIP Electric Station Flood Mitigation costs for "Hasbrouck Heights ($14.6 million), State Street ($12.2 million), Clay Street ($13.5 million), and Waverly ($17.9 million)" for $58.2 million in total for the same subprogram. Please identify the CWIP balances by project for ES 2 Electric Station Flood Mitigation subprogram for the remaining 41.19 million.	The paragraph introducing the CWIP discussion highlights the largest components of CWIP by subprogram, in this case the Hasbrouck Heights, State Street, Clay Street, and Waverly projects (note Waverly's balance was incorrectly listed as $17.9 million rather than the correct $18.0 million). **Figure 2** on the other hand depicts the full CWIP balance by subprogram. The CWIP balances by project for each of the Electric Station Flood Mitigation projects is provided below:	**Section II.C.2.**

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td></td><td></td><td><table><tr><th>Project</th><th>Q3 2022 CWIP Balance</th></tr><tr><td>Academy Street</td><td>$0</td></tr><tr><td>Clay Street</td><td>$13,472,003</td></tr><tr><td>Front Street</td><td>$9,767,419</td></tr><tr><td>Hasbrouck Heights</td><td>$14,535,338</td></tr><tr><td>Kingsland</td><td>$2,341,261</td></tr><tr><td>Lakeside Avenue</td><td>$3,431,600</td></tr><tr><td>Leonia</td><td>$5,958,310</td></tr><tr><td>Market Street</td><td>$2,230</td></tr><tr><td>Meadow Road</td><td>$2,196,464</td></tr><tr><td>Orange Valley</td><td>$2,334,015</td></tr><tr><td>Ridgefield 13kV</td><td>$5,675,397</td></tr><tr><td>Ridgefield 4kV</td><td>$0</td></tr><tr><td>State Street</td><td>$12,216,817</td></tr><tr><td>Toney’s Brook</td><td>$3,235,564</td></tr><tr><td>Waverly</td><td>$18,022,455</td></tr><tr><td>Woodlynne</td><td>$6,203,817</td></tr></table></td><td></td></tr>
<tr><td>RCR-IM-10</td><td>With reference to pages 11 through 12, Table 6 ES 2 Program Overhead Allocations of September 30, 2022, please provide the breakdown of increased labor costs during the Third Quarter 2022 by supervisory, administrative, planning and contract labor categories and subprogram.</td><td>A comparison of the breakdown of overhead costs incurred on the Program during the second and third quarters of 2022 has been added to the report in new Table 7 – Q2 and Q3 2022 Overhead Cost Comparison.</td><td>Table 7</td></tr>
<tr><td>RCR-IM-11</td><td>With reference to page 16 of the Independent Monitor’s Draft Third Quarter 2022 Report, concerning communications provided by PSE&G’s switchgear vendor, Powercon, please indicate if Powercon has provided the “more detailed and frequent status updates” referred to in the Draft Second and Third Quarter 2022 Reports regarding remaining major equipment deliveries.</td><td>Concerning the additional information from Powercon, PSE&G requested and has received details in Powercon’s production schedules and information from the sub-vendors/suppliers.</td><td>No change</td></tr>
<tr><td>RCR-IM-12</td><td>With reference to page 16, Table 10 ES 2 Electric Substation Flood Mitigation Switchgear Deliveries as of September 30, 2022, please explain if the revised delivery dates for 4 kV switchgear for Clay Street, Front Street, Lakeside Avenue, Orange Valley, Waverly and Woodlynne are based on communications from Powercon, or estimates by PSE&G.</td><td>The noted switchgear delivery dates are provided by the vendor.</td><td>No change</td></tr>
<tr><td>RCR-IM-13</td><td>With reference to pages 17 through 18, Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of September 30, 2022, the risk and contingency subprogram total is $29.3 million, a reduction of $12.5 million from the $41.8</td><td>The changes to R&C on the Electric Station Flood Mitigation during the third quarter of 2022 resulted in the R&C balance in the Electric Station Flood</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	million risk and contingency subprogram total reported by the IM in the Second Quarter 2022 Report, Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of June 30, 2022, pages 16 through 17. Please specify how the $12.5 million in risk and contingency funds were applied to which Electric Station Flood Mitigation projects.	Mitigation subprogram decreasing by $12.5 million. The overall estimate for the subprograms remained unchanged as the drawdown in R&C matched an increase in the base estimate for projects that had updated estimates in the quarter (Electric Station Flood Mitigation projects: Clay Street, Meadow Road, Kingsland, Ridgefield 4kV (decreased $100K as part of the project closeout), Waverly, and Woodlynne. Details of these estimate changes are provided in the specific subsection for the project.	
RCR-IM-14	With reference to page 19 of the Third Quarter 2022 Report, the IM states that "there is adequate R&C remaining in the subprogram." Please confirm that there is adequate risk and contingency remaining in the subprogram given in-service date slippage driven by switchgear delivery delays.	Based on the current risk profile and work remaining in the subprogram, the total subprogram forecast is approximately $356.9 million, the $29.3 million in R&C represents approximately 8% of that forecast. With three projects currently complete and an additional four projects forecasted to reach in-service by the end of 2022, it appears the contingency is adequate based on the remaining work particularly as the current forecasts are based on the currently forecasted in-service dates. However, R&C is ultimately an estimate based on the information known or expected to be known at the time of the estimate.	No change
RCR-IM-15	With reference to Table 11 ES 2 Electric Substation Flood Mitigation Project Cost Status as of September 30, 2022, on page 17 and the Findings and Observations on pages 17 and 18, for the $1.35 million increased forecast for Front Street from $26.15 million (Second Quarter 2022 Report) to $27.50 million please specify the costs for "bringing six circuits from [outside plant] to [inside plant], additional handling of contingency feeder rows, and additional costs for contingency wire checker and contingency disassembly."	Regarding the details associated with the increased forecast for the Front Street project: • $0.3 million: updated forecast for brining in six circuits from OP to IP and additional handling of contingency feeder rows; • $0.9 million: civil construction additional scope, relay tech direct project charges, added contingency wire checker, and additional contingency switchgear disassembly costs; and, • $0.2 million: late charges for Division material and handling of contingency feeder rows.	No change
RCR-IM-16	With reference to page 19 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain for which projects the primary risk is "resource availability to support schedule requirements."	The resource risk is primarily in the Metro and Southern Division and potentially impacting these projects for the Metro Division: Lakeside, Clay Street, Waverly, Orange Valley, and Toney's Brook; and for	**Section III.A.**

ID #	Question/Comment	IM Response	Report Changes
		the Southern Division: State Street, Woodlynne, and Woodbury.	
RCR-IM-17	With reference to page 19 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain for which projects the primary risk is weather-related impacts.	The weather-related impacts have the potential to impact any of the remaining projects depending on the nature of the impacts, which may involve such specific risks localized flooding or resources being pulled from project work to support recovery efforts.	No change
RCR-IM-18	With reference to page 20 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain the safety incidents and what is the estimated cost of the 52 day slippage in the forecasted in-service date for the Clay Street project.	The forecasted in-service date slipped due to a construction safety incident on the OP Civil work, local flooding that impacted installation of the switchgear building foundation, and additional test pits required to confirm OP MH&C underground design. The safety incident involved an excavator excavating a new duct bank that scraped the top of the concrete and shifted it. The machine was used to lift the concrete with the bucket, which exposed four conduits. The bucket never touched the conduits, however the top of two conduits came off with the concrete. Construction at the site was paused for an incident investigation and to make sure all appropriate safety procedures were reviewed and followed. The costs associated with this delay consist of flood cleanup costs of approximately $56K and schedule acceleration of approximately $100K.	No change
RCR-IM-19	With reference to page 20 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how the Clay Street "[p]roject schedule recovery" cost of $600,000 was calculated, what exactly does it include, and was this based on the 52 slippage of the in-service date to March 23, 2023 noted at the end of the third quarter of 2022 or other factors? If other factors are involved, please describe how they impact the project schedule recovery cost.	The $600K in costs associated with "project schedule recovery" are comprised of roughly $100K in additional Civil and Electrical supervision and roughly $475K in construction contractor increases. The total delay from the late receipt of construction permits was determined to be approximately six months, with three months recovered through these efforts.	**Section III.A.2.**
RCR-IM-20	With reference to page 22 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how the Kingsland project cost of $0.4 million for the "[e]xtended project duration: shift from Q2 2023 to Q4 2023 in-service" date was calculated and what components are included in that calculation (labor, borrowing costs, equipment storage, site costs, etc.). Please explain why delay costs have not	The $400K cost increases on Kingsland associated with the extended project duration was based on the in-service date being revised to December 2023 based on the decision to utilize the contingency switchgear on Ridgefield 13kV as the permanent Kingsland	**Section III.A.5.**

ID #	Question/Comment	IM Response	Report Changes
	been calculated and reported for all project delays affecting the ES 2 Electric Station Flood Mitigation Project subprogram and all other programs.	switchgear (representing a cost savings vs. ordering new switchgear). However, this resulted in the carrying costs extended by a full year at a rate of $25K/month for 2023 and an additional five months in 2024 added for post in-service closeout at $20K/month, representing a total of $400K in additional costs. The carrying costs include typical project management activities and resources (e.g. project manager, staff engineer, cost engineer, scheduler, etc.).	
RCR-IM-21	With reference to page 29 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain how "there is no significant cost impact expected from this shift in installations" of the remaining 874 to be installed Fuse Savers from the first half of 2022 to the second half of 2022.	This is a shift in the timing of when the Fuse Saver installations are targeted, but there is no cost impact from installing in the fall of 2022 instead of the spring of 2022.	No change
RCR-IM-22	With reference to page 31 of the Independent Monitor's Draft Third Quarter 2022 Report, please detail the "higher observed costs per unit on the Fuse Savers testing and installation labor," that contributed to the third quarter of 2022 $2.0 million increase above the $145 million stipulated budget for the Contingency Reconfiguration subprogram.	In the ES 2 filing, PSE&G estimated installation of these devices would range between $11,721 for single-phase devices and $18,262 for two-phase devices. The Black & Veatch "Electric Cost-Benefit Analysis" study attached to PSE&G's ES 2 filing noted that *"PSE&G currently does not have any of these devices installed; therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices."* The construction standard and training were developed through implementation of the Fuse Saver pilot program that commenced in November 2020 and was primarily completed in January 2021 (PSE&G installed 80 devices in this initial period, then opted to install the remaining units in inventory to capture additional cost and performance data, resulting in a total of 113 units installed as of the end of 2021). The actual costs observed through the Fuse Saver pilot program actuals saw single phase devices average $35,216 and two-phase devices average $48,031, significantly higher than the estimate at the time of the ES 2 filing. The cost increases were primarily driven by:	**Section III.B.**

ID #	Question/Comment	IM Response	Report Changes
		• The ES 2 filing estimate not including management costs, tree trimming, storage, or traffic control costs; • Higher material costs than estimated, including pole replacements at multiple locations (pole replacement costs not included in the initial estimate assumptions, adds approximately $10,000 in costs per unit); and, • Average labor hours 4x higher than the ES 2 filing estimate and increased labor rates since filing. PSE&G's approach on forecasting the Fuse Saver scope during its execution is based on a quarterly review of the actual cost data and related installation status information to inform and update the installation plan. PSE&G continues seeking to optimize the number of Fuse Savers installed in alignment with the overall budget for the subprogram. For example, given the added costs of the pole replacements, PSE&G considered attempting to avoid such locations, but in many cases the existing equipment and height/spacing requirements on the pole required installation of a new pole.	
RCR-IM-23	With reference the findings and observations on page 31 of the Independent Monitor's Draft Third Quarter 2022 Report, please explain what accounted for the Contingency Reconfiguration subprogram forecast increasing by $2.0 million, to a total of $147.6 million, above the Stipulation budget of $145.0 million.	Higher Fuse Savers cost per unit in installation and testing/commissioning were the primary drivers to the increased forecast.	**Section III.B.**
RCR-IM-24	With reference to page 37 of the Independent Monitor's Draft Third Quarter 2022 Report, please provide costs details on the $7.4 million increase in the Grid Modernization ADMS subprogram budget, involving changes in the Outage Management System from one to two production releases, at an increased cost of $7.4 million, increasing total ADMS subprogram budget from $53.47 million to $60.90 million. Please provide breakdown of increased costs by project category (supervisory, administrative, planning and contract labor, equipment).	Regarding this $7.4 million increase, it was comprised of the following costs: • PSE&G Employees: +$4.13 million, comprised of: o Supervisory: $0.8 million; o Labor: $3.2 million; and, o IT resources: $0.14 million. • Staff Augmentation: +$3.32 million, comprised of: o Supervisory: $0.14 million; o Testing: $0.74 million;	**Section III.D.**

ID #	Question/Comment	IM Response	Report Changes
		o Direct Labor: $2.41 million; and, o Materials: $0.03 million.	
RCR-IM-25	With reference to page 38, Table 21 ES 2 Life Cycle Station Upgrade Project Status as of September 30, 2022, please explain the disposition of the subprogram risk and contingency total of $2.3 million for Hamilton, Paramus, Plainfield, Woodbury and State Street substation projects compared to the risk and contingency total in Table 23 ES 2 Life Cycle Station Upgrade Project Status as of June 30, 2022 in the Independent Monitor's Draft Second Quarter 2022 Report on page 38.	The R&C balance for the Electric Stipulated Base projects is $1.4 million, which is effectively the amount that remains between the Stipulation budget ($100 million) and the current base estimates for the Life Cycle Station Upgrades projects ($98.6 million).	No change
RCR-IM-26	With reference to pages 42 and 43, Table 23 – ES 2 Gas M&R Summary Status as of September 30, 2022, please confirm the remaining risk and contingency allocation of $200,000 is adequate for the Camden project after the transfer to base of $3.1 million given ongoing exceedances affecting the Project.	The $200K remaining R&C balance on Camden reflects the realization of certain risks that resulted in R&C funds being transferred to the Base estimate. The remaining balance is relatively low compared to the overall project costs, however, with this project forecasted to go in-service in December 2022 the work is fairly well advanced and there is less remaining risk. Ultimately the R&C and the overall estimate represent an estimate based on the information known at the time on what the expected risks and overall project costs will be, however, actual conditions can and do change that can increase or decrease the actual costs compared to the estimate.	No change
RCR-IM-27	With reference to page 44, for the Camden Gas M&R Project, please explain how the "$9.9 million of actuals will be journaled out in October 2022 to reflect the split of the LPA scope of the Camden project that removes the LPA scope from the ES 2 project[]" will affect the $26.7 million actuals to date and how will that change affect the Gas M&R subprogram stipulated budget of $101 million and accounting for the $27.8 million increase over the stipulated budget by PSE&G to $128.8 million and how will that be reconciled with $24.6 million for Gas M&R risk and contingency (refer back to page 2, Table 1 – ES 2 Subprograms & Stipulated Base Status as of September 30, 2022).	The removal of the LPA scope from the project costs is expected to reduce the $26.7 million in current actual costs on the Camden project by approximately $9.9 million (though the project will also continue to incur actual costs related to the ES 2 project scope). The $128.8 million current estimate for the Gas M&R subprogram does not include LPA-related costs, however, the R&C balance decreased by $5.5 million reflecting updated estimates in the third quarter of 2022 on the Camden and East Rutherford projects that saw a collective $5.5 million Base estimate increase. This leaves the current R&C balance for the Gas M&R subprogram at $19.1 million.	**Table 1**

ID #	Question/Comment	IM Response	Report Changes
RCR-IM-28	With reference to page 45, for the East Rutherford Gas M&R Project, please provide additional details on how project costs are allocated between PSE&G and Transco and whether that contributed to the "delay in finalizing the Transco pipeline agreement addendum that pushed a forecasted payment." Please provide details on the costs and payment schedule for the pipeline agreement and how these are accounted for in the East Rutherford Gas M&R Project.	During the preliminary design phase, PSE&G Asset Management and the Project Team reviewed the overall general construction scope and duration with Transco. Based on that review, Transco provided an estimate of the scope and costs for its support. The estimated Transco support cost is included in the Interconnection Agreement. Within 6-10 weeks of execution of the Interconnection Agreement, the full amount of estimated support cost is paid by PSE&G to Transco as a deposit to be drawn against periodically as the support scope is executed. Transco periodic updates of scope/estimates, actual and forecast costs are discussed during the project review meetings between PSE&G and Transco. If Transco increases its forecast for its support cost, due to scope changes or other reasons, they notify PSE&G accordingly for discussion, negotiation, and agreement. The Interconnection Agreement is then amended as agreed between Transco and PSE&G. If the total cost incurred by Transco for the complete scope of the support is less than the total amount of deposit paid by PSE&G, Transco is obligated to return the difference. The Transco support costs are captured by PSE&G as an ES 2 capital investment cost on a separate project WBS.	No change

Danielle Lopez
Associate Counsel-Regulatory

Law Department
80 Park Plaza, T10, Newark, New Jersey 07102-4194
Tel: 973.430.6479
Email: danielle.lopez@pseg.com

PSEG Services Corporation

November 30, 2023

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: Energy Strong II Program Quarterly Report
Q3 - 2023

Dear Secretary Golden:

Enclosed for filing is the report on the second quarter of the Energy Strong II program for July to September, 2023.

The Energy Strong II program was addressed by a Board Order dated September 11, 2019 September 11 Order) in Docket Nos. EO18060629 & GO18060630. That order adopted a Stipulation pursuant to which PSE&G is operating the program known as Energy Strong II.

Paragraph 45 of that Stipulation requires reports on:

- the estimated quantity of work and the quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;
- the forecasted and actual Energy Strong II costs-to-date for the quarterly reporting period and for the program-to-date; where projects are identified by major category (with actual variances from forecasted amounts expressed in dollar and percentage terms);
- the estimated Energy Strong II project completion date, and estimated completion dates for each Energy Strong II sub-program and the Program as a whole;
- Anticipated changes to ES II projects, if any;
- Actual capital expenditures made in the normal course of business on similar projects, identified by comparable Energy Strong II sub-program; and
- Any other performance metrics concerning the IIP required by the Board.

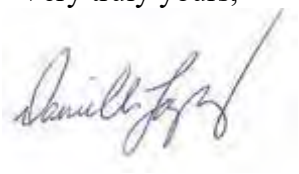
The reporting requirements listed in paragraph 45 of the Stipulation are addressed by the enclosed materials.

Paragraphs 46, 47, and 49 of that Stipulation provide that PSE&G shall report quarterly on the performance of Electric Stations and gas M&R Stations; Contingency Reconfiguration Strategies

and Grid Modernization ADMS in a manner that compares the performance of the upgraded or new plant to pre-Energy Strong II Plant.

Please contact the undersigned with any questions or concerns.

Very truly yours,



Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Malike Cummings
Matko Illic
Caroline Vachier

ES II Program Quarterly Report to the Board of Public Utilities

Q3-2023 – July, August, September 2023

Table of Contents

Metric 1 – Estimated Quantity of Work 3

Energy Strong II Electric Program 3

Electric Station Flood Mitigation 3

Electric Contingency Reconfiguration 6

Electric Grid Modernization - Communication System ..... **Error! Bookmark not defined.**

Electric Grid Modernization - ADMS 7

Electric Stipulated Base Subprogram 7

Energy Strong II Gas M&R 9

Metric 2 – Estimated Program and Subprogram Completion Dates 9

Program 13

Subprograms ..... **Error! Bookmark not defined.**

Electric Flood Mitigation 14

Contingency Reconfiguration 15

Grid Modernization 15

Electric Stipulated Base 16

Gas Metering & Regulation (M&R) 17

Metric 3 – SAIFI/MAIFI 18

Metric 4 – Quarterly and Program To-Date Forecast and Actual Costs 19

Flood Mitigation 19

Contingency Reconfiguration 19

Grid Modernization - Communication 20

Grid Modernization – ADMS 20

Electric Stipulated Base 21

Gas M&R 21

Similar Projects Comparable to ES II Subprograms 22

Detailed Tables for Metric 3 for Q3 2022 – SAIFI/MAIFI 23

Table M3.1 - Quarterly Report Non-Major Event Performance during the quarter. (#47) 23

Metric 1 – Estimated Quantity of Work

For each Energy Strong II Subprogram:

A. Estimated quantity of work

i. **For the subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction.

NOTE: This quarterly report covers Program to date performance up to the Q3-2023 period – July 1, 2023, through September 30, 2023. At the end of the period, all subprograms/projects have advanced through varying stages of planning, authorization and execution and completion. Where applicable, forecasted, and actual units of work and/or major tasks completed are provided.

Energy Strong II Electric Program

Electric Station Flood Mitigation

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes implementation of flood mitigation (FM) measures at 16 Substations. The Stipulation also allows for inclusion of substation switchgear Life Cycle (LC) replacement, subject to funding available within the Flood Mitigation budget cap.

In 2021, the Front St substation was initially included in the program as a Lifecycle (LC) station, as identified in the list of LC stations identified in the stipulation. This station was added into the subprogram as a Lifecycle replacement project for potential funding however, during the project initiation, the project team discovered that in addition to life cycle improvements, Front St. station also requires flood mitigation as it is located within an identified FEMA mapping zone and below the NJ DEP flood Hazard area level.

One (1) project (Constable Hook) will be included in the execution of another transmission project and will not be executed under the ESII program. Subsequently, the Energy Strong II stipulation was amended by removing the Constable Hook substation project from the Program and replacing it with flood mitigation work on the Company's Front Street substation.

Constable Hook is not included in the updates below.

ii. **Planned to Date:** Major work planned to the end of September 2023 (Front St included):

a. Completion of Key Drawing Review (KDR) for 16 FM stations, cost estimate update to Study Level (50% confidence level) transition approval for 16 flood stations, estimate update to Conceptual (70% CL) level estimate transition for 16 projects and estimate update to Definitive (90% CL) level estimate for 15 stations.
b. Issue Switchgear purchase orders for 14 flood stations.
c. Detailed Engineering on 16 flood stations.
d. Site plan approvals for 10 flood stations
e. 12 ESFM projects in active construction.
f. Switchgear installation at 13 flood stations.
g. Elimination of Ridgefield and Market St 4 kV stations and full completion of 13kv conversion work.
h. In-service of 10 flood stations.
i. Close out completed for Ridgefield 4kV Elimination and Market Street Elimination

B. Quantity of Work Completed to Date:

As of the end of September 2023 most projects in the ESFM program progressed on schedule. Orange Valley and Front St received delivery of their Powercon equipment. Lakeside now is the only project awaiting delivery and with its forecasted in-service date beyond the end of the Program Period. All projects issued their major equipment purchase orders. Ten projects requiring site plan have received approval. In Q3 2023, twelve projects were in construction. To date the Ridgefield 4kV and Market St Elimination projects completed their 4kV to 13kV conversions, and transfer of customers from Ridgefield and Market St 4kV Substations. Eleven projects (Academy, Leonia, Ridgefield 13kV, Hasbrouck Heights, Kingsland, State St, Waverly 4kV, Toney's Brook, Clay St, Meadow Rd and Front St (contingency)) have placed switchgears into service.

- 15 projects of the 16 flood mitigation projects have transitioned to Definitive (90%) level estimate, 1 project (Lakeside) is at Conceptual (70%) level estimate.
- Purchase Orders have been awarded for major equipment (switchgear) on all 14 projects requiring switchgear.
- 16 projects have substantially completed detailed engineering design.
- 9 projects have awarded POs for A/E design. PSE&G is the engineer for the other 7 projects.

- 16 projects have completed scope lockdown.
- 16 projects have awarded purchase orders for civil construction phase commencement.
- 15 projects have awarded a purchase order for electrical construction commencement.
- 10 projects requiring site plan approval have submitted applications, 10 have been approved.
- 12 projects (Leonia, State St, Clay St, Waverly, Front St, Meadow Road, Kingsland, Lakeside, Toney's Brook, Orange Valley, Woodlynne and Hasbrouck Heights) are in construction. Four projects are completed with construction (Market St, Academy, Ridgefield 4kV and Ridgefield 13kV). Two projects are complete with closeout (Market St. and Ridgefield 4kV).
- Leonia has successfully energized new 13kV switchgear #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Ridgefield has successfully energized new 13kV switchgear #2 and placed it into service. All circuits on both switchgears have been cutover to the new switchgears.
- Waverly has successfully energized the 26kV switchgear and placed it into service. All 26kV circuits have been cutover to the new switchgear.
- Hasbrouck Heights has successfully energized new 4kV switchgear and placed it into service. All circuits have been cutover to the new switchgear.
- Academy has successfully energized the new 13kV switchgear and placed it into service at the new Fairmont station. All circuits from the Academy station have been upgraded from 4kV to 13kV and transferred to the new station.
- Front St has successfully energized the contingency 4kV equipment and placed it into service.
- State St has successfully energized the new 4kV switchgear and placed it into service.
- Toney's Brook has successfully energized the new 4kV switchgear and placed it into service.
- Clay St has successfully energized the new 4kV switchgear and placed it into service.
- Contingency switchgear from Leonia was disassembled and delivered and set at Meadow Road. Meadow Road has successfully energized the new 13kV switchgear and placed it into service. All circuits have been cutover to the new switchgear.
- Contingency switchgear from Ridgefield was disassembled and delivered and set at Kingsland. Kingsland has successfully energized the new 13kV switchgear and placed it into service.
- The Ridgefield 4kV and Market St Elimination projects completed their 4kV to 13kV conversions, eliminated the flood risk to customers supplied from Ridgefield and Market St 4kV Substations. Both station elimination projects went in-service.
- Market St has completed inside plant (substation) civil demolition and ISRA related activities.

- Project closeout completed for Ridgefield 4kV Elimination and Market St Elimination.

Electric Contingency Reconfiguration

A. Estimated Quantity of Work:

i. **Project:** CR Subprogram estimated 1,467 Reclosers and 1,344 Fuse Savers to be installed over the life of the program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following.

a. Install 1,467 Reclosers program to date (PTD) by end of Q3-2022
b. Commission 1,467 Reclosers PTD by the end of Q3-2023
c. Install and commission 1,348 Fuse Saver program to date (PTD) by end of Q3-2023

B. Quantity of Work Completed to Date:

Reclosers

All Reclosers planned for the program have been completed

- All 1,467 Reclosers planned for the Program have been engineered, installed and commissioned into service.

Fuse Savers

- 1,326 Fuse Savers have been installed program to date to the end of Q3 2023.
- 1,325 of the 1,326 installed Fuse Savers were commissioned into service.
- 1,393 Fuse Savers have been engineered for installation.

Electric Grid Modernization - Communication System

A. Estimated Quantity of Work:

i. **Project:** The Company will install a communication system upgrade, comprised of a new Wireless Radio Network and fiber technology (approximately 134.5 miles of new fiber), and 218 Retrofit Substation RTU's. SCADA system communications at designated substations will be cutover to the fiber network. The system will provide coverage for all switching devices on the system to facilitate both system and customer equipment communication moving forward. The

Company will install 1,176 Remote Device Management (RDM) on the reclosers on system using Blueframe Software.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following:

a. Complete In-Service on thirty-four (34) Fiber Install Projects
b. Build and Install Blueframe Software for RDM
c. Develop Process to Prepare for RDM Cutover

B. Quantity of Work Completed to Date:

- One (Edison) project in progress, pending railroad crossing outage to be scheduled for 1st Quarter 2024)
- Completed Cutover Process for RDM for 2 Reclosers/Division with final release and validated functionality.

Electric Grid Modernization - ADMS

A. Estimated Quantity of Work:

i. **Project:** The Advanced Distribution Management System (ADMS) subprogram is made up of Supervisory Control and Data Acquisition (SCADA) Platform Upgrade; new Outage Management System (OMS); deployment of additional modules of Distribution Management System (DMS) and Distributed Energy Resources Management System (DERMS) Applications. This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included the following:

a. Close Out DMS/DERMS Project Financially.
b. Complete SIT Round 5
c. Begin SIT Planning 6 and 7.

B. Quantity of Work Completed to Date:

- Completed Close Out DMS/DERMS Project Financially.
- Completed SIT 5

- Completed SIT 6

Electric Stipulated Base Subprogram

A. Estimated Quantity of Work:

i. **Project:** The Electric Stipulated Base provides for investment of up to $100 million to be spent at the Company's discretion toward electric outside plant higher design and construction standards ("Outside Plant" or OP-HDS) and/or electric 4kV substations life cycle subprograms identified in the Energy Strong II petition. Based on agreement, new underground distribution circuits (State St. OP project), which is part of the State St. Flood Mitigation project scope, is also included in Stipulated Base.

ii. **Planned to Date:** Major work planned to the end of September 2023 included:

a. Completion of Key Drawing Review (KDR) for all stations, cost estimate update to Study Level (50% confidence level) transition approval for 5 Stations, estimate update to Conceptual (70% CL) level estimate transition for 4 projects and estimate update to Definitive (90% CL) level estimate for 4 stations.
b. Issuance of Switchgear purchase orders for the 4 IP Lifecycle stations.
c. A/E contract awards for all Lifecycle stations.
d. Detailed design for all 4 IP Lifecycle stations and the State St OP Project.
e. Approval of Site Plan applications for all four (4) IP Lifecycle stations.
f. Start civil construction at all Lifecycle stations.
g. Start electrical construction at all Lifecycle stations.
h. In-service of the contingency switchgear at Paramus LC.
i. Installation of 4kv switchgear, commencement of electrical construction and commissioning at four (4) IP lifecycle stations.
j. Energization and in service of Hamilton. All circuits cutovers.
k. Energization and in-service of Paramus and Plainfield 4kv switchgears.
l. Energization and in-service of first circuit at New State St OP.
m. Demolition of existing feeder rows complete at Plainfield and Hamilton.

B. Quantity of work Completed to Date:

- As of the end of June 2023, Key Drawing Review (KDR), estimate update to Definitive 90% level and URB estimate transition have been completed for all Lifecycle stations.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) have awarded major equipment PO's.
- Four electric 4kV life cycle substation projects (Plainfield, Paramus, Hamilton, & Woodbury) and the State St OP project have substantially completed detailed engineering design and locked their scopes.
- Site plan applications have been approved on all four IP electric 4kV life cycle substation projects.
- All life cycle substation projects are in civil construction.
- All life cycle substation projects are in electrical construction.
- Paramus 4kV substations life cycle project contingency switchgear is in-service.
- Hamilton, Paramus and Plainfield have set and energized their new 4kV switchgears and placed them into service.
- State St OP has placed the first OP circuit into service from the New State St substation.
- Hamilton completed all circuit cutovers.

Energy Strong II Gas M&R

A. Estimated Quantity of work:

i. **Project:** The estimated quantity of work for this subprogram includes implementation of flood mitigation measures at 2 of the 6 Gas M&R Substations (Camden and East Rutherford) listed in the Program Stipulation and life cycle upgrades at all 6 M&R Substations (Camden, Central, East Rutherford, Mt. Laurel, Paramus, and Westampton). This remains unchanged from the beginning of the Energy Strong II Program.

ii. **Planned to Date:** Major work planned to the end of September 2023 included:

A. Camden

a. Complete fit out of control / SCADA building.

b. Complete electrical installation and terminations.

c. Complete installation of gas chromatograph and odor analyzer.
d. Complete wiring and commission new electrical switchgear.
e. Switch over to permanent power.
f. Begin demolition of decommissioned piping and structures

B. East Rutherford
a. Complete electrical installation and terminations.
b. Complete erection of regulator building.
c. Completed control building fit out.
d. Demobilize contractor.
e. Restore laydown area.

C. Central
a. Complete Control / SCADA building fit out.
b. Complete tie in for 60 psi distribution system.
c. Completed installation of piping, conduits in pipe rack.
d. Complete inlet tie-ins from Transco and Texas Eastern.
e. Begin Commissioning of regulation runs and ancillary equipment.

D. Mount Laurel
a. Complete foundations for regulation and SCADA buildings, MEG Unit.
b. Fabrication of piping run segments.
c. Begin installation of electrical conduits.
d. Begin installation of below grade piping runs, inlet and outlet piping regulating runs.
e. Receive and set SCADA building.
f. Receive and begin erection of regulation building.
g. Receive, connect and commission full flow bypass skid.

E. Paramus
a. Continue to receive materials and equipment.
b. Complete electrical power upgrade.
c. Begin fabrication of contingency bypass skids.
d. Begin distribution tie-ins for contingency skids.
e. Set up secure front yard to receive contingency skids.

F. Westampton

a. Install screening on fence.

b. Close out all building permits.

B. Quantity of Work Completed to Date:

Major work completed as to the end of June 2023 includes the following:

Camden

- Commissioned electrical switchgear and metering sections.
- Completed switchover to permanent power.
- Commissioned gas chromatograph and odor analyzer.
- Commissioned heaters.
- Relocated propane vaporizers.
- Completed fit out of Control / SCADA building.
- Completed electrical wire pulls and terminations.
- Completed removal of hazardous materials in building slated for demolition.
- Began removal of decommissioned piping.

East Rutherford

- Completed erection of control building.
- Completed control building fit out.
- Demobilized contractor.
- Restored laydown area.
- Completion of punch list items and final site grading remain.

Central

- Completed tie-in of Transco supply.
- Completed tie-in to 60 psi distribution systems.
- Completed installation of pipe rack foundations and supports.
- Completed commissioning of regulator runs.
- Completed fit out of control/SCADA building.
- Completed installation of electrical conduit, pulling wire and terminations.
- Put Central M&R station in-service.

Mt. Laurel

- Completed foundations for regulation and SCADA buildings, MEG Unit.
- Continued fabrication of piping run segments.
- Began installation of electrical conduits.
- Began installation of below grade piping runs, inlet and outlet piping regulating runs.

- Received and set SCADA building.
- Received and began erection of regulation building.
- Received, connected and commissioned full flow bypass skid.

Paramus

- Continued to receive materials and equipment.
- Completed electrical power upgrade.
- Began fabrication of contingency bypass skids.
- Began distribution tie-ins for contingency skids.
- Set up and secured front yard to receive contingency skids.

Westampton

- Completed requirements needed to satisfy township engineer in order to close out permits. These included replacement of one light, cleaning of storm sewer and change fabric on perimeter fence.
- Installed fence screening.
- Closed out building permits.

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated ES II project completion date, and estimated completion dates for each ESII sub-program and the Program as a whole.

Note - Project completion date is defined by the date project closeout report is completed.

Energy Strong II Program

Program	Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Energy Strong II Program	Mar-24	Nov-24
Gas Energy Strong II Program	Oct-24	Apr-25

Energy Strong II Accelerated Recovery Programs

Program	Subprogram	Forecast In-Service	Timeline for Completion
Electric Energy Strong II Program	Electric Flood Mitigation	Mar-24	Nov-24
	Contingency Reconfiguration	Sep-23	Jun-24
	Grid Modernization - Communication	Dec-23	Dec-23
	Grid Modernization - ADMS	Dec-23	Jun-24
Gas Energy Strong II Program	M&R Stations Upgrade	Oct-24	Apr-25

Electric Station Flood Mitigation

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Market Street Substation Elimination	Jun-21A	Dec-21A		
Meadow Road Substation	May-23	Nov-23		
Academy Street Substation	Oct-21A	Jun-22A		
Ridgefield 4kv Substation Elimination	May-21A	Dec-21A		
Ridgefield 13kv Substation	Dec-22A	Jun-23A		
Hasbrouck Substation	Nov-22A	Jul-23A		
Kingsland Substation	Jul-23A	Jun-24		
Lakeside Avenue Substation	Mar-24	Nov-24		
Leonia Substation	Nov-22A	May-23A		
Clay Street Substation	Apr-23	Apr-24		
State Street Substation	Dec-22A	Feb-24		
Toney's Brook Substation	May-23A	Apr-24		
Waverly Substation*	Dec-23	Nov-24		
Woodlynne Substation	Dec-23	Aug-24		
Orange Valley Substation	Dec-23	Jul-24		
Front Street Substation	Dec-23	Jul-24		

*** Based on updated schedule resulting from Waverly Site Plan application denial by City of Newark**

[1] Project completion date is defined by the date project closeout report is completed.

Contingency Reconfiguration

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Reclosers	Jan-22A	Jul-22A		
Fuse Savers	Sep-23	Jun-24		

Grid Modernization - Communication

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Wireless Network	Dec-21A	Dec-21A		
Fiber	Dec-23	Dec-23		
Retrofits Reclosers	Dec-21A	Jun-22A		
Radio Commissioning	Dec-23	Jun-24		
RDM Recloser	Jun-23	Dec-23		

Grid Modernization - ADMS

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Platform/SCADA Upgrade	Jun-22A	Jun-22A		
DMS/DERMS	Jan-23A	Jun-23		
OMS	Oct-23	Apri-24		In-service date may shift to March 2024

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R)

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Camden (M&R)	Dec-22A	Oct-23		
East Rutherford (M&R)	Dec-22A	Jul-23A		
Westampton (M&R)	Oct-21A	May-22A		

[1] Project completion date is defined by the date project closeout report is completed.

ENERGY STRONG II STIUPLATED BASE PROGRAM

Program	Forecast In-Service (Last major equipment)	Timeline for Completion
Electric Stipulated Base	Dec-23	Jun-24
Gas Stipulated Base	Oct-24	Apr-25

Electric Stipulated Base

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Paramus Substation	Nov-22A	Nov-23		
Hamilton Substation	Oct-22A	May-23A		
Woodbury Substation	Oct-23	May-24		
Plainfield	Dec-22A	Jun-23A		
State Street Outside Plant	Dec-22A	Jun-24		
Outside Plant – Higher design Standard (OP-HDS)	Dec-23	Jun-24		

[1] Project completion date is defined by the date project closeout report is completed.

Gas Metering & Regulation (M&R) Stipulated Base

Project	Forecast In-Service	Timeline for Completion[1]	Updates	Expected Changes
Mt. Laurel (M&R)	Nov-23	May-24		
Central (M&R)	Oct-23	May-24		
Paramus (M&R)	Oct-24	Apr-25		

[1] Project completion date is defined by the date project closeout report is completed.

Metric 3 – SAIFI/MAIFI

A. This metric includes data for circuits involved in the Major and Non-Major events in **Q3-2023.**

- There were No Major Events in Q3-2023, therefore only the Non-major Event Report is included for this period.

Detailed tables for this metric (Non-major Events) are included at the end of this report.

Metric 3 Reports Included for Q3-2023

- Table M3.1 – Quarterly Report Non-Major Event Performance. (Clause #47)

Metric 4 – Quarterly and Program To-Date Forecast and Actual Costs

Flood Mitigation

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$21,823,572	$23,911,726	($2,088,155)	-9%
Other Costs	$17,264,124	$23,437,904	($6,173,780)	-26%
Total	$39,087,696	$47,349,631	($8,261,934)	-17%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$98,412,431	$127,696,768	($29,284,337)	-23%
Other Costs	$211,004,606	$189,982,203	$21,022,402	11%
Total	$309,417,037	$317,678,971	($8,261,934)	-3%

Contingency Reconfiguration

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$1,154,631	$1,104,426	$50,205	5%
Other Costs	$2,923,136	$2,574,976	$348,160	14%
Total	$4,077,768	$3,679,402	$398,365	11%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$58,770,602	$52,105,393	$6,665,209	13%
Other Costs	$86,356,023	$92,622,867	($6,266,844)	-7%
Total	$145,126,625	$144,728,260	$398,365	0%

Grid Modernization - Communication

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	($14,870)	($1,333,340)	$1,318,470	-99%
Other Costs	$587,044	$1,761,987	($1,174,943)	-67%
Total	$572,174	$428,647	$143,527	33%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$2,467,700	$13,011,072	($10,543,372)	-81%
Other Costs	$62,531,136	$51,844,237	$10,686,900	21%
Total	$64,998,836	$64,855,308	$143,527	0%

Grid Modernization – ADMS

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$36,023	$629,007	($592,984)	-94%
Other Costs	$3,857,829	$4,111,640	($253,811)	-6%
Total	$3,893,852	$4,740,647	($846,795)	-18%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$4,239,317	$11,764,068	($7,524,751)	-64%
Other Costs	$55,631,457	$48,953,500	$6,677,956	14%
Total	$59,870,774	$60,717,568	($846,795)	-1%

Electric Stipulated Base

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$898,928	$202,665	$696,263	344%
Other Costs	$5,320,350	$7,381,646	($2,061,296)	-28%
Total	$6,219,279	$7,584,311	($1,365,032)	-18%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$28,475,630	$33,640,422	($5,164,792)	-15%
Other Costs	$62,369,572	$58,569,813	$3,799,760	6%
Total	$90,845,203	$92,210,235	($1,365,032)	-1%

Gas M&R

Quarter Performance (Q3-2023, July to September)

Cost Type	Actuals	Forecast*	Variance ($)	Variance (%)
Material	$3,319,342	$4,910,520	($1,591,178)	-32%
Other Costs	$8,280,762	$9,636,908	($1,356,146)	-14%
Total	$11,600,104	$14,547,428	($2,947,324)	-20%

Program to Date (September 2023)

Cost Type	Actuals	Forecast	Variance ($)	Variance (%)
Material	$25,840,602	$39,452,423	($13,611,821)	-35%
Other Costs	$85,983,318	$75,318,821	$10,664,497	14%
Total	$111,823,920	$114,771,244	($2,947,324)	-3%

* Quarterly forecast is as of September 1, 2023

Similar Projects Comparable to ES II Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable ESII sub-program:

ES II Investment Category	Description	Applicable ES II Subprograms	Capital Spend on Comparable Non-ES II Programs
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from wind, flying debris, and water damage in anticipation of future Major Storm Events; Strengthen the resiliency of the Company's delivery system	* Electric Stations Flood Mitigation * OP-HDS * Gas M&R Flood Mitigation * Electric Contingency Reconfiguration * Electric Grid Modernization	$ 45,195,720
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * Gas M&R	$ 94,316,405
Total	**Capital Spend from September 2019 to September 2023**		**$ 139,512,125**

Detailed Tables for Metric 3 for Q3-2023 – SAIFI/MAIFI

Table M3.1 - Quarterly Report Non-Major Event Performance during the quarter. (#47)

This report includes quarterly non-major event performance combining all events

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
ADA 8011	0.00130	0.00140	106.59	0.07590	0.00011	0.00025	190.55	0.04808
ADA 8012	0.00140	0.00068	105.00	0.05254	0.00160	0.00064	80.90	0.05210
ADA 8015	0.00076	0.00009	125.36	0.00268	0.00139	0.00021	36.67	0.00775
ADA 8021	0.00060	0.00034	39.84	0.00508		0.00008	195.64	0.01511
ADA 8022	0.00360	0.00141	45.85	0.08044	0.00324			
ADA 8023	0.00159	0.00043	176.88	0.05644	0.00147	0.00064	66.03	0.04221
ADA 8024	0.00063	0.00030	49.87	0.00811		0.00012	73.70	0.00912
ADA 8025	0.00059	0.00023	34.75	0.00679	0.00041	0.00002	27.47	0.00042
ADA 8026	0.00020	0.00014	144.32	0.01479	0.00001			
ALD 8012	0.00246	0.00090	88.82	0.09278		0.00002	161.00	0.00384
ALD 8013	0.00300	0.00065	70.14	0.05012	0.00026	0.00028	71.58	0.01977
ALD 8015	0.00357	0.00148	51.50	0.07728		0.00088	38.36	0.03362
ALD 8016	0.00215	0.00121	87.13	0.08348	0.00129	0.00006	103.75	0.00661
ALD 8022	0.00224	0.00070	77.05	0.04252	0.00054	0.00001	76.00	0.00085
ALD 8023	0.00206	0.00094	67.11	0.05120	0.00200	0.00048	64.54	0.03067
ALD 8024	0.00002	0.00001	51.61	0.00251				
ALD 8025	0.00225	0.00140	42.76	0.06011	0.00175	0.00077	51.13	0.03913
ALD 8026	0.00110	0.00040	189.11	0.03887	0.00114	0.00051	46.73	0.02395
ARC 4001		0.00042	15.00	0.00624				
ARC 4003	0.00023	0.00023	99.00	0.02270				
AUD 4003	0.00082	0.00020	122.50	0.02365		0.00118	75.67	0.08926
BAO 8003	0.00229	0.00116	31.48	0.03098	0.00148	0.00007	145.22	0.00977
BAO 8006	0.00076	0.00058	132.41	0.10855	0.00036	0.00002	81.00	0.00155
BAO 8008	0.00006	0.00001	81.75	0.00130				
BAO 8013	0.00288	0.00095	91.93	0.07640		0.00003	47.00	0.00142
BAO 8014	0.00138	0.00084	80.66	0.04137	0.00105	0.00007	78.33	0.00533
BAO 8015	0.00060	0.00051	87.02	0.04290	0.00044			
BAO 8023	0.00305	0.00042	69.51	0.02819		0.00003	475.00	0.01531
BAO 8033	0.00204	0.00045	87.78	0.04117	0.00101			
BAO 8043	0.00330	0.00182	47.53	0.07989		0.00018	73.55	0.01294
BAO 8044	0.00224	0.00050	74.75	0.02936	0.00597	0.00115	29.00	0.03340
BEA 8001	0.00157	0.00027	61.80	0.01563	0.00144	0.00003	62.62	0.00162
BEA 8003	0.00017	0.00004	46.44	0.00195	0.00033	0.00002	7.00	0.00014
BEA 8004	0.00010	0.00017	60.51	0.01157	0.00018			
BEA 8010	0.00138	0.00052	110.52	0.05293	0.00095	0.00125	36.91	0.04610

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
BEF 8012	0.00115	0.00035	116.11	0.03754		0.00004	178.44	0.00710
BEF 8013	0.00063	0.00038	76.27	0.02442	0.00171	0.00039	48.45	0.01899
BEF 8014	0.00108	0.00044	62.23	0.02632	0.00186	0.00005	91.04	0.00475
BEF 8015	0.00116	0.00068	63.06	0.03652	0.00013	0.00004	89.71	0.00364
BEF 8016	0.00080	0.00054	154.86	0.09106	0.00187	0.00043	61.09	0.02597
BEF 8021	0.00047	0.00032	112.37	0.04112	0.00019	0.00009	69.07	0.00618
BEF 8023	0.00134	0.00082	116.88	0.09529	0.00020	0.00022	22.36	0.00488
BEM 8001	0.00716	0.00120	131.49	0.07051	0.00795	0.00261	30.81	0.08041
BEN 8011	0.00052	0.00032	111.70	0.02616		0.00008	120.55	0.00960
BEN 8012	0.00302	0.00096	111.90	0.04210	0.00075	0.00116	90.11	0.10468
BEN 8014	0.00068	0.00020	117.06	0.00939	0.00048	0.00004	136.22	0.00548
BEN 8015	0.00012	0.00015	115.11	0.01703				
BEN 8016	0.00128	0.00039	74.94	0.02376	0.00080	0.00003	69.91	0.00186
BEN 8021	0.00060	0.00055	74.47	0.03094	0.00037	0.00032	61.11	0.01980
BEN 8022	0.00277	0.00132	117.27	0.07413	0.00043	0.00170	8.22	0.01401
BEN 8023	0.00056	0.00060	82.91	0.04347		0.00075	14.98	0.01123
BEN 8025	0.00041	0.00072	72.26	0.03071	0.00193	0.00027	9.00	0.00243
BEN 8026	0.00257	0.00091	33.10	0.02869	0.00078	0.00094	18.85	0.01772
BLO 4002		0.00023	213.03	0.03279				
BLO 4004		0.00004	138.42	0.00518				
BLO 4006		0.00019	184.17	0.02210		0.00068	68.82	0.04675
BLO 4007		0.00034	108.50	0.03146				
BLO 4009	0.00022	0.00039	52.09	0.02121				
BLO 4012					0.00039	0.00032	6.00	0.00193
BLO 4014		0.00053	150.36	0.07724		0.00018	6.00	0.00107
BLO 4015	0.00072	0.00070	88.88	0.06310		0.00023	8.00	0.00183
BLO 4016		0.00086	62.95	0.04790		0.00112	66.82	0.07494
BLO 4017		0.00032	64.00	0.01859				
BLO 4018	0.00065	0.00044	88.89	0.04532		0.00035	51.00	0.01776
BOR 4001	0.00013	0.00024	144.38	0.02264	0.00042	0.00028	47.75	0.01353
BOR 4002	0.00018	0.00028	60.23	0.01562	0.00042	0.00021	30.00	0.00626
BRU 8011	0.00048	0.00010	95.60	0.00890		0.00008	124.48	0.00996
BRU 8012	0.00140	0.00104	38.76	0.03879	0.00215	0.00041	90.42	0.03718
BRU 8013	0.00173	0.00025	110.80	0.02238		0.00004	168.80	0.00712
BRU 8021	0.00134	0.00042	51.04	0.01104	0.00106	0.00005	70.24	0.00319
BRU 8022	0.00060	0.00050	115.02	0.01495	0.00003	0.00004	109.49	0.00431
BRU 8023	0.00117	0.00049	43.18	0.01041	0.00049			
BUS 8011	0.00060	0.00044	73.82	0.02945		0.00004	127.00	0.00566
BUS 8012	0.00233	0.00029	127.52	0.03119	0.00079	0.00019	88.05	0.01637
BUS 8013	0.00039	0.00039	130.96	0.03495	0.00104	0.00022	98.00	0.02126
BUS 8015	0.00024	0.00017	129.92	0.02429	0.00024	0.00001	149.38	0.00095
BUS 8023	0.00188	0.00104	44.44	0.04111	0.00208	0.00036	26.50	0.00941
CAR 8002	0.00018	0.00010	103.07	0.01138	0.00008	0.00009	79.00	0.00692
CAR 8003	0.00008	0.00004	80.62	0.00304	0.00006			
CAR 8004	0.00022	0.00011	135.12	0.00540	0.00034	0.00033	21.54	0.00719
CAR 8006	0.00008	0.00006	39.01	0.00105				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CAS 8001	0.00142	0.00101	76.82	0.07861		0.00059	13.04	0.00775
CAS 8002	0.00017	0.00016	107.18	0.01737	0.00040	0.00003	36.00	0.00099
CAT 4003	0.00025	0.00025	6.00	0.00149				
CAT 4005	0.00017	0.00001	597.00	0.00597				
CAT 4006		0.00024	72.00	0.01742				
CAT 4009	0.00024	0.00039	80.63	0.02959				
CED 8011	0.00204	0.00138	69.28	0.07747	0.00083	0.00006	157.79	0.00892
CED 8013	0.00067	0.00016	163.02	0.03975		0.00004	104.06	0.00468
CED 8016	0.00097	0.00070	139.05	0.10119	0.00013	0.00029	77.49	0.02224
CED 8021	0.00263	0.00117	42.47	0.04564	0.00018	0.00004	76.00	0.00309
CED 8022	0.00226	0.00094	64.01	0.07450	0.00358	0.00021	54.29	0.01117
CED 8025	0.00054	0.00030	99.48	0.01486		0.00025	44.27	0.01096
CED 8026	0.00098	0.00018	96.89	0.02075	0.00102	0.00036	49.37	0.01765
CET 4012	0.00114	0.00141	79.17	0.10537		0.00156	53.51	0.08356
CET 4019	0.00070	0.00070	37.67	0.02629		0.00007	547.24	0.04073
CHA 4001		0.00013	73.06	0.00332	0.00022	0.00012	21.00	0.00255
CHA 4002		0.00017	229.00	0.03992				
CHA 4004	0.00033	0.00086	41.55	0.03577				
CHA 4005		0.00030	69.40	0.02097		0.00047	54.00	0.02540
CHA 4008		0.00026	149.00	0.03858				
CHA 4012	0.00068	0.00099	103.71	0.05275		0.00052	31.23	0.01620
CHA 4013		0.00022	71.83	0.01581	0.00026	0.00028	138.00	0.03834
CHA 4014		0.00064	292.01	0.03046	0.00020			
CHA 4015		0.00022	153.76	0.03138	0.00028	0.00028	20.00	0.00566
CHE 4008		0.00027	92.63	0.02678				
CHS 4001		0.00031	153.98	0.05336		0.00006	222.00	0.01387
CHS 4003		0.00012	19.00	0.00224				
CHS 4006		0.00017	457.50	0.09976				
CHS 4007		0.00002	56.00	0.00126				
CHS 4008	0.00023	0.00039	73.12	0.03517				
CIN 8001	0.00111	0.00055	122.00	0.06213	0.00010	0.00057	210.47	0.11912
CIN 8002	0.00049	0.00043	89.93	0.03238	0.00015	0.00067	185.95	0.12382
CIN 8004	0.00007	0.00003	67.92	0.00241		0.00063	123.51	0.07762
CIN 8005	0.00028	0.00039	54.53	0.02113	0.00014	0.00009	57.00	0.00501
CIN 8009	0.00050	0.00025	141.25	0.03254	0.00079	0.00002	149.95	0.00245
CIN 8031	0.00088	0.00032	143.47	0.01574		0.00004	100.45	0.00364
CIN 8032	0.00157	0.00068	81.13	0.03143		0.00007	57.08	0.00411
CIN 8033	0.00054	0.00060	79.69	0.04570	0.00053	0.00048	58.03	0.02765
CIN 8043	0.00243	0.00219	101.28	0.14568	0.00095	0.00093	91.15	0.08438
CLA 4005		0.00006	76.00	0.00448				
CLA 4006		0.00024	63.64	0.01801		0.00028	164.33	0.04552
CLA 4008		0.00016	102.50	0.01095		0.00020	14.00	0.00275
CLE 4001		0.00067	52.25	0.03690	0.00012	0.00012	28.00	0.00347
CLE 4011		0.00085	41.75	0.04072				
CLE 4016	0.00050	0.00139	63.61	0.08871				
CLF 8012	0.00119	0.00027	70.16	0.01637	0.00079	0.00002	66.00	0.00118

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CLF 8013	0.00066	0.00023	64.92	0.01612	0.00128	0.00002	126.47	0.00302
CLF 8014	0.00095	0.00021	122.15	0.01542	0.00049	0.00014	24.00	0.00336
CLF 8015	0.00686	0.00173	45.79	0.07563	0.00966	0.00231	48.96	0.11309
CLF 8023	0.00156	0.00068	78.80	0.04824	0.00210	0.00088	17.19	0.01520
CLF 8024	0.00111	0.00103	56.61	0.04757	0.00254	0.00029	40.79	0.01184
CLF 8025	0.00092	0.00021	99.43	0.01390	0.00134			
CLK 8012	0.00027	0.00015	26.26	0.00563	0.00008	0.00003	17.00	0.00057
CLK 8013	0.00011	0.00011	67.58	0.01366		0.00027	99.53	0.02674
CLK 8014	0.00070	0.00051	90.27	0.02349	0.00043	0.00073	13.50	0.00979
CLK 8015	0.00175	0.00140	53.99	0.07709	0.00210	0.00099	35.20	0.03498
CLK 8016	0.00106	0.00097	17.75	0.02150	0.00007	0.00000	369.00	0.00029
CLK 8022	0.00099	0.00096	36.09	0.01337		0.00026	39.37	0.01042
CLK 8023	0.00002	0.00002	31.25	0.00034	0.00008	0.00002	63.00	0.00100
CLK 8024	0.00037	0.00014	49.06	0.00330				
CLK 8031		0.00016	56.68	0.01082		0.00016	42.00	0.00664
CLK 8032	0.00171	0.00306	86.10	0.16706	0.00054	0.00095	51.21	0.04888
CLK 8033	0.00057	0.00159	39.30	0.08732	0.00055	0.00027	41.08	0.01099
CLK 8034	0.00052	0.00019	138.37	0.00798	0.00012			
CLK 8041		0.00021	128.67	0.01218	0.00061	0.00038	172.00	0.06592
CLK 8042	0.00070	0.00057	10.13	0.00554	0.00037	0.00000	151.00	0.00006
CON 8001	0.00123	0.00074	49.22	0.03802	0.00079			
COR 8013	0.00237	0.00026	119.36	0.01207	0.00050	0.00224	45.97	0.10294
COR 8015	0.00214	0.00044	83.94	0.02335		0.00001	305.83	0.00426
COR 8025	0.00065	0.00024	43.92	0.01036	0.00062	0.00044	30.28	0.01322
COR 8033	0.00397	0.00068	68.12	0.03302		0.00004	122.69	0.00435
COR 8034	0.00217	0.00067	88.36	0.04539	0.00329	0.00072	122.20	0.08779
COR 8035	0.00099	0.00016	542.55	0.08476				
COR 8041	0.00238	0.00087	68.13	0.04026	0.00153	0.00054	9.73	0.00523
COR 8042	0.00158	0.00063	76.44	0.02864	0.00047	0.00054	23.74	0.01280
CRA 4001		0.00026	62.48	0.01619		0.00026	91.00	0.02383
CRA 4003		0.00058	50.63	0.02649	0.00017	0.00060	79.85	0.04783
CRA 4004	0.00016	0.00047	59.24	0.02491				
CRA 4009		0.00036	68.33	0.02487				
CRA 4010		0.00073	84.60	0.06377				
CRA 4011		0.00027	66.00	0.02016	0.00014	0.00018	117.00	0.02063
CRA 4012		0.00037	143.13	0.03455	0.00018	0.00012	115.00	0.01387
CRA 4016	0.00029	0.00038	102.93	0.03404				
CRX 8001	0.00100	0.00049	83.67	0.04344	0.00066	0.00125	189.64	0.23768
CRX 8003	0.00040	0.00041	100.73	0.03758	0.00051	0.00047	41.20	0.01924
CRX 8004	0.00128	0.00063	112.33	0.04511	0.00170	0.00050	145.25	0.07192
CRX 8005	0.00080	0.00050	102.20	0.05726	0.00017	0.00004	18.57	0.00076
CRX 8007	0.00198	0.00112	88.75	0.11410	0.00003	0.00215	99.95	0.21522
CRX 8008	0.00112	0.00052	86.38	0.04260	0.00081	0.00018	61.52	0.01134
CRX 8009	0.00081	0.00064	87.92	0.05623	0.00170	0.00065	30.64	0.01999
CUL 4001	0.00098	0.00094	152.00	0.14126				
CUL 4012		0.00069	113.49	0.08070		0.00065	32.24	0.02101

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
CUT 8001	0.00107	0.00042	39.89	0.01972		0.00007	61.64	0.00432
CUT 8002	0.00012	0.00007	163.83	0.00685	0.00011	0.00006	118.91	0.00700
CUT 8003	0.00289	0.00124	80.43	0.08582	0.00152	0.00083	27.31	0.02267
CUT 8004	0.00288	0.00205	112.13	0.21608	0.00082	0.00022	762.78	0.16515
CUT 8005	0.00067	0.00048	76.28	0.04550		0.00006	6.00	0.00037
CUT 8006	0.00037	0.00060	93.32	0.05233	0.00068	0.00058	13.09	0.00757
CUT 8007	0.00261	0.00117	66.91	0.06548	0.00457	0.00251	138.56	0.34749
CUT 8008	0.00125	0.00063	118.71	0.05503	0.00077	0.00066	22.15	0.01455
CUT 8010	0.00144	0.00060	223.33	0.08988	0.00088	0.00097	13.74	0.01337
CUT 8031	0.00042	0.00014	182.26	0.01471	0.00015	0.00008	19.18	0.00153
CUT 8033	0.00067	0.00075	68.42	0.04152	0.00191	0.00082	97.49	0.07950
CUT 8034	0.00380	0.00128	81.19	0.09521	0.00511	0.00047	82.34	0.03867
CUT 8041	0.00047	0.00049	102.94	0.05030	0.00033	0.00009	34.01	0.00317
CUT 8042	0.00076	0.00052	142.57	0.08197	0.00113	0.00077	53.23	0.04106
CUT 8043	0.00255	0.00244	76.63	0.18682	0.00095	0.00354	79.53	0.28133
CUT 8044	0.00012	0.00033	67.78	0.02200	0.00031	0.00055	190.90	0.10531
CXC 8012	0.00106	0.00035	73.14	0.01629		0.00000	713.00	0.00085
DAY 8001	0.00222	0.00069	65.27	0.02911	0.00040	0.00005	73.13	0.00352
DAY 8002	0.00019	0.00005	191.44	0.00719		0.00003	6.00	0.00015
DEA 4001	0.00024	0.00017	75.85	0.01215		0.00023	107.76	0.02526
DEA 4009		0.00016	78.67	0.00863				
DFD 8007	0.00445	0.00216	74.57	0.16276	0.00270	0.00186	45.43	0.08440
DFD 8008	0.00063	0.00067	86.37	0.06272	0.00134	0.00035	84.86	0.02959
DFD 8009	0.00098	0.00038	80.46	0.02557	0.00080	0.00014	86.11	0.01182
DFD 8031	0.00256	0.00134	48.77	0.05390	0.00004	0.00011	244.70	0.02698
DFD 8041	0.00140	0.00065	134.57	0.06599	0.00129	0.00004	136.54	0.00522
DOR 8012	0.00213	0.00039	50.16	0.01495				
DOR 8013	0.00022	0.00043	60.84	0.02166		0.00003	118.00	0.00399
DOR 8015	0.00286	0.00172	44.31	0.06885	0.00126	0.00055	40.17	0.02225
DOR 8024	0.00126	0.00048	43.08	0.02067	0.00046	0.00002	58.00	0.00111
DOR 8025	0.00175	0.00066	59.02	0.03816	0.00187	0.00127	159.11	0.20201
DOR 8035	0.00311	0.00236	127.15	0.12402	0.00213	0.00286	18.26	0.05220
DOR 8036	0.00408	0.00064	103.08	0.06537	0.00981	0.00197	50.33	0.09927
DOR 8044	0.00253	0.00164	48.73	0.04869	0.00230	0.00134	29.87	0.03991
DOR 8045	0.00199	0.00054	79.38	0.04002	0.00592	0.00205	156.95	0.32169
DUM 4001	0.00026	0.00043	88.58	0.03366				
DUM 4002		0.00024	97.00	0.02371		0.00010	74.27	0.00715
DUM 4004	0.00025	0.00011	64.08	0.00953		0.00021	44.67	0.00928
DUM 4007	0.00047	0.00026	202.50	0.02180				
DVB 8011	0.00069	0.00028	21.56	0.00435		0.00002	132.00	0.00263
DVB 8012	0.00014	0.00022	57.83	0.01133	0.00023	0.00007	37.87	0.00249
DVB 8013	0.00062	0.00027	67.81	0.00996	0.00147	0.00000	52.00	0.00019
DVB 8014	0.00002	0.00002	12.37	0.00027	0.00007			
DVB 8015	0.00025	0.00026	183.71	0.00572		0.00001	351.00	0.00279
DVB 8021	0.00002	0.00001	260.00	0.00114	0.00002			
DVB 8022	0.00016	0.00003	48.87	0.00071		0.00000	323.00	0.00116

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
DVB 8023	0.00062	0.00032	99.31	0.02731	0.00016	0.00042	109.94	0.04568
DVB 8025	0.00013	0.00006	119.16	0.00130		0.00001	148.00	0.00094
EAO 4006		0.00075	40.06	0.02721				
EAO 4008		0.00085	76.30	0.03925				
EAO 4013		0.00096	43.37	0.04116				
EAO 4019		0.00046	132.22	0.04778				
EAO 4023	0.00091	0.00075	205.38	0.12784		0.00010	160.44	0.01667
EAO 4024		0.00051	94.98	0.02018				
EAT 8011	0.00156	0.00130	89.85	0.07833	0.00144	0.00141	59.30	0.08357
EAT 8012	0.00057	0.00061	75.64	0.05846		0.00027	12.00	0.00323
EAT 8013	0.00138	0.00111	37.80	0.03944	0.00038	0.00017	21.14	0.00360
EAT 8014	0.00012	0.00011	70.17	0.00976	0.00008	0.00001	15.00	0.00014
EAT 8021	0.00089	0.00072	57.80	0.03280	0.00052	0.00043	17.00	0.00723
EAT 8022	0.00143	0.00043	88.83	0.02605	0.00196	0.00005	90.72	0.00451
EAT 8023	0.00114	0.00076	63.41	0.05969	0.00280	0.00227	32.37	0.07358
EAT 8025	0.00038	0.00009	101.54	0.00298	0.00031	0.00057	27.30	0.01561
EDI 4003		0.00030	61.67	0.01924		0.00026	6.14	0.00161
EDI 4006		0.00032	38.00	0.01080		0.00047	6.00	0.00282
EDI 4007		0.00039	40.00	0.01474	0.00019	0.00057	25.25	0.01427
EDI 4008	0.00056	0.00039	17.67	0.00385		0.00057	14.37	0.00820
EDI 4009		0.00035	24.63	0.00567		0.00034	6.00	0.00202
ENG 4004								
ENG 4005								
ENG 4006		0.00008	346.00	0.02638		0.00005	86.56	0.00403
ENG 4007		0.00010	139.00	0.01429				
ENG 4012		0.00025	65.12	0.01633				
ENG 4016								
ENG 4017	0.00021	0.00020	74.50	0.00426				
EWI 4001		0.00008	90.02	0.00694				
EWI 4002	0.00051	0.00102	64.69	0.05538				
EWI 4003		0.00007	81.63	0.00520				
EWI 4004		0.00025	242.90	0.03756		0.00036	83.60	0.03008
EWI 4006		0.00036	160.28	0.02690		0.00040	8.00	0.00323
EWI 4007	0.00031	0.00052	48.96	0.02178		0.00031	15.00	0.00468
EWI 4008		0.00026	191.49	0.05015				
FAR 4002		0.00058	42.19	0.02164				
FAR 4005		0.00022	119.40	0.01626		0.00031	73.12	0.02276
FAR 4006	0.00026	0.00051	141.87	0.05931	0.00021			
FAW 8011	0.00071	0.00054	107.77	0.05763	0.00066	0.00081	121.62	0.09855
FAW 8012	0.00107	0.00075	72.13	0.05940	0.00030	0.00004	120.08	0.00492
FAW 8013	0.00122	0.00033	116.15	0.01661		0.00122	23.76	0.02892
FAW 8014	0.00131	0.00060	102.51	0.03419		0.00014	87.95	0.01225
FAW 8015	0.00028	0.00027	26.89	0.00365	0.00025			
FAW 8016	0.00164	0.00044	90.99	0.03383	0.00097	0.00076	47.28	0.03579
FAW 8022	0.00089	0.00054	105.00	0.02390				
FAW 8023	0.00113	0.00031	94.96	0.00684	0.00059	0.00117	22.54	0.02644

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
FAW 8026	0.00098	0.00084	34.57	0.02676	0.00004	0.00001	453.12	0.00307
FED 4004	0.00072	0.00022	290.00	0.06452	0.00038			
FED 4010								
FED 4013								
FED 4018		0.00054	88.11	0.04389				
FED 4021	0.00075	0.00037	54.50	0.02034				
FED 4022	0.00068	0.00003	159.00	0.00469				
FED 4030		0.00044	110.34	0.02282	0.00029			
FEN 8041	0.00082	0.00034	46.06	0.01647	0.00063	0.00053	31.10	0.01657
FIT 8003	0.00126	0.00078	118.83	0.10582				
FOH 4002	0.00072	0.00073	111.00	0.08086				
FOH 4003	0.00051	0.00050	94.50	0.04809				
FOH 4004	0.00013	0.00048	23.26	0.01130				
FOH 4006		0.00038	55.18	0.01065				
FOH 4007		0.00187	13.34	0.02490				
FOH 4008		0.00042	71.00	0.02330		0.00031	109.13	0.03414
FOR 4009	0.00000	0.00027	87.50	0.02246				
FOT 8004	0.00065	0.00089	62.31	0.07043		0.00003	94.00	0.00296
FOU 8012	0.00343	0.00174	61.43	0.08986		0.00063	128.43	0.08086
FOU 8014	0.00031	0.00010	96.45	0.00825	0.00027	0.00009	307.99	0.02746
FOU 8022	0.00011	0.00010	54.86	0.00529				
FOU 8024	0.00024	0.00015	57.84	0.01108	0.00020	0.00004	83.88	0.00367
FRA 8011	0.00003	0.00001	140.00	0.00147				
FRA 8012	0.00007	0.00003	8.00	0.00035	0.00025	0.00010	49.52	0.00493
FRA 8013	0.00022	0.00015	56.38	0.01018	0.00014	0.00000	36.00	0.00001
FRA 8021	0.00023	0.00012	7.30	0.00165		0.00018	12.00	0.00221
FRA 8023	0.00021	0.00011	48.59	0.00571				
FRO 4006	0.00026	0.00026	56.00	0.01480				
FRO 4007	0.00070	0.00090	45.28	0.03543		0.00004	18.00	0.00066
FRO 4008	0.00054							
FRO 4009	0.00031	0.00032	293.94	0.09962		0.00030	108.00	0.03245
GBK 8011	0.00133	0.00048	85.46	0.03307	0.00116	0.00053	21.01	0.01124
GBK 8013	0.00136	0.00065	49.00	0.01892	0.00281	0.00002	124.56	0.00193
GBK 8014	0.00168	0.00060	72.12	0.02965	0.00135	0.00078	82.18	0.06446
GBK 8021	0.00126	0.00072	38.29	0.03490	0.00018	0.00026	94.07	0.02400
GBK 8022	0.00218	0.00084	54.31	0.03369	0.00123	0.00005	120.74	0.00610
GBK 8023	0.00136	0.00081	59.15	0.04199	0.00079	0.00039	82.44	0.03255
GBK 8024	0.00102	0.00091	111.54	0.12556	0.00076	0.00005	212.60	0.00973
GBK 8025	0.00214	0.00120	44.72	0.04564	0.00203	0.00048	163.90	0.07899
GET 4003	0.00112	0.00091	61.49	0.05942	0.00172			
GET 4004	0.00018				0.00052			
GET 4007	0.00078	0.00105	50.70	0.05340	0.00036			
GET 4008	0.00126	0.00087	9.80	0.00850	0.00106	0.00078	50.91	0.03979
GET 4009	0.00087	0.00056	123.04	0.01714	0.00046			
GRE 4002		0.00012	108.24	0.00875		0.00031	68.13	0.02099
GRE 4003	0.00039	0.00040	39.94	0.01622		0.00032	92.00	0.02948

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
GRE 4004	0.00019	0.00020	69.00	0.01333		0.00002	173.00	0.00420
GRE 4005		0.00015	76.76	0.01184				
GRE 4006		0.00008	64.50	0.00492				
GRE 4007	0.00047	0.00052	124.33	0.03894				
GRN 4001		0.00104	81.24	0.08215	0.00098	0.00036	132.26	0.04796
GRN 4003		0.00021	107.00	0.02288		0.00020	87.00	0.01776
GRN 4008	0.00042	0.00027	82.60	0.02212	0.00064	0.00039	53.67	0.02072
GRN 4009		0.00068	81.23	0.05522		0.00065	23.00	0.01484
GRN 4011	0.00082	0.00057	120.67	0.04630		0.00080	73.00	0.05852
HAC 4005	0.00024	0.00024	75.12	0.01906	0.00015			
HAC 4006	0.00019	0.00056	152.04	0.08589				
HAC 4007	0.00018	0.00016	80.50	0.01046				
HAC 4009	0.00020	0.00016	43.79	0.00911				
HAC 4010	0.00007	0.00010	39.77	0.00416				
HAC 4011	0.00081	0.00034	93.00	0.03208				
HAC 4012	0.00021	0.00010	33.33	0.00163				
HAC 4013	0.00023	0.00028	67.60	0.01750				
HAC 4016	0.00020	0.00027	94.32	0.02057	0.00027	0.00027	8.00	0.00214
HAC 4018	0.00013	0.00018	89.68	0.01470				
HAD 4002		0.00080	137.26	0.10512		0.00001	122.00	0.00180
HAD 4003		0.00001	369.00	0.00371		0.00001	21.00	0.00018
HAD 4005		0.00024	86.46	0.02060		0.00005	48.31	0.00219
HAD 4008		0.00013	82.33	0.00941				
HAD 4009		0.00019	146.61	0.01842				
HAD 4010		0.00049	154.44	0.06024				
HAL 4001		0.00002	112.50	0.00156				
HAL 4002		0.00030	78.67	0.02580				
HAL 4004		0.00004	116.14	0.00408				
HAL 4005	0.00074	0.00020	198.50	0.02322		0.00069	68.06	0.04686
HAL 4007						0.00044	6.00	0.00265
HAL 4008	0.00054	0.00039	90.96	0.01765	0.00018			
HAM 4007		0.00010	46.38	0.00328				
HAM 4008		0.00032	54.47	0.01966		0.00020	39.00	0.00793
HAM 4009		0.00028	50.58	0.01556	0.00019			
HAR 4001		0.00040	113.50	0.04585				
HAR 4006		0.00039	124.00	0.06396	0.00110	0.00044	77.60	0.03397
HAR 4014		0.00059	165.81	0.09629		0.00117	22.23	0.02597
HAR 4015		0.00046	171.00	0.07807				
HAR 4018	0.00043	0.00043	171.00	0.07348				
HAR 4021		0.00040	139.42	0.05593	0.00011	0.00004	74.00	0.00303
HAT 8011	0.00015	0.00028	130.70	0.03922				
HAT 8012	0.00117	0.00077	54.21	0.03898	0.00010	0.00003	124.84	0.00373
HAT 8015	0.00019	0.00013	67.77	0.00895	0.00008			
HAT 8021	0.00041	0.00013	31.09	0.00358	0.00031	0.00050	48.77	0.02426
HAT 8022	0.00068	0.00091	67.06	0.03857	0.00039	0.00008	92.73	0.00779
HAT 8023	0.00020	0.00013	128.46	0.01949				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
HAT 8027	0.00085	0.00014	125.04	0.00827	0.00193	0.00025	50.86	0.01289
HAT 8034	0.00004	0.00000			0.00005			
HAT 8035	0.00080	0.00060	53.20	0.03130	0.00020	0.00003	87.80	0.00287
HAT 8037	0.00125	0.00058	111.56	0.04832		0.00011	198.05	0.02183
HAW 8032	0.00188	0.00112	80.62	0.05650	0.00264			
HAW 8041	0.00123	0.00014	116.25	0.01631	0.00005	0.00013	33.74	0.00434
HBG 4007		0.00034	11.00	0.00378				
HBG 4008		0.00000						
HID 8011	0.00099	0.00045	61.43	0.02045		0.00001	143.75	0.00137
HID 8013	0.00028	0.00023	125.15	0.02879	0.00058	0.00010	48.44	0.00503
HID 8034	0.00030	0.00026	52.93	0.01680	0.00061	0.00008	33.00	0.00263
HID 8035	0.00098	0.00056	76.29	0.04630	0.00153	0.00060	54.42	0.03249
HID 8042	0.00078	0.00021	115.61	0.02107		0.00013	60.56	0.00791
HID 8043	0.00028	0.00018	125.59	0.01925	0.00035	0.00009	198.91	0.01853
HID 8044	0.00190	0.00092	96.68	0.06810	0.00051	0.00078	208.98	0.16286
HID 8045	0.00174	0.00032	115.22	0.03682	0.00163	0.00031	26.00	0.00803
HNC 8015	0.00062	0.00033	91.75	0.02052	0.00066	0.00028	23.61	0.00662
HNC 8021	0.00165	0.00060	71.31	0.02175	0.00154	0.00143	55.68	0.07986
HNC 8022	0.00094	0.00026	105.33	0.02054	0.00032			
HNC 8024	0.00143	0.00040	80.29	0.03343	0.00080	0.00016	62.22	0.00978
HNC 8025	0.00029	0.00020	126.26	0.02124	0.00029	0.00013	109.53	0.01447
HOE 8037	0.00590	0.00166	50.55	0.06688	0.00205			
HOE 8038	0.00300	0.00122	30.33	0.04414	0.00168			
HOE 8044	0.01231	0.00256	44.61	0.10503	0.00578	0.00066	166.09	0.10881
HOE 8047	0.00203	0.00075	38.06	0.01764	0.00256	0.00059	12.30	0.00730
HOE 8048	0.00079	0.00036	134.01	0.02391	0.00047			
HOM 8001	0.00372	0.00077	54.11	0.03386	0.00107	0.00136	90.33	0.12317
HOM 8002	0.00013	0.00001	86.00	0.00072				
HOM 8003	0.00085	0.00022	70.52	0.01459	0.00023	0.00075	70.94	0.05336
HOM 8012	0.00213	0.00148	29.67	0.05052	0.00317	0.00034	26.00	0.00879
HOM 8014	0.00337	0.00137	34.61	0.05173	0.00236	0.00003	78.00	0.00217
HOM 8025	0.00073	0.00040	43.01	0.02199	0.00015	0.00017	117.07	0.02004
HOM 8032	0.00577	0.00208	59.95	0.10408		0.00010	110.00	0.01108
HOM 8033	0.00268	0.00127	109.08	0.09908	0.00254	0.00175	35.81	0.06268
HOM 8034	0.00482	0.00105	63.51	0.07339	0.00126	0.00085	129.00	0.10931
HOM 8041	0.00603	0.00104	32.94	0.02027		0.00000	394.00	0.00031
HOM 8042	0.00022	0.00009	37.73	0.00398				
HOM 8044	0.00049	0.00012	87.51	0.00608				
HOM 8046	0.00263	0.00116	45.18	0.05232	0.00140	0.00059	15.00	0.00880
IRO 4002								
IRO 4003		0.00000				0.00022	43.00	0.00955
IRO 4005	0.00052	0.00074	86.51	0.06203				
IRO 4009	0.00028	0.00028	21.00	0.00595		0.00028	61.00	0.01714
IRO 4011	0.00063	0.00060	19.86	0.01192	0.00054			
IRO 4012		0.00023	61.00	0.01417				
IRO 4013	0.00025	0.00024	255.00	0.06211		0.00011	169.00	0.01789

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
IRO 4014		0.00075	82.00	0.06111		0.00046	272.00	0.12450
IRV 4002	0.00050	0.00124	77.76	0.10014		0.00058	57.67	0.03362
IRV 4004	0.00077	0.00141	113.88	0.15724				
IRV 4006	0.00042	0.00120	67.94	0.07233	0.00043	0.00084	18.00	0.01503
IRV 4011	0.00062	0.00033	323.50	0.02804				
IRV 4013		0.00042	112.00	0.04694		0.00044	69.00	0.03010
IRV 4017	0.00036	0.00051	44.36	0.02946	0.00025	0.00003	159.00	0.00449
IRV 4019		0.00034	102.62	0.03536		0.00050	64.96	0.03271
IRV 4021	0.00040	0.00032	116.33	0.02566				
IRV 4022		0.00025	112.00	0.01388		0.00002	162.00	0.00400
JAC 8011	0.00021	0.00020	55.83	0.01278				
JAC 8012	0.00039	0.00017	73.60	0.01336	0.00027	0.00005	23.28	0.00112
JAC 8021	0.00022	0.00004	23.37	0.00088				
JAC 8022	0.00041	0.00012	105.12	0.01287	0.00006			
JAC 8023	0.00059	0.00058	37.66	0.02336	0.00069	0.00033	111.69	0.03725
JAC 8024	0.00031	0.00026	105.08	0.01982	0.00024	0.00028	86.23	0.02454
JAC 8025	0.00081	0.00029	65.83	0.01021	0.00041			
JAC 8033	0.00109	0.00064	92.21	0.04911	0.00050	0.00056	37.88	0.02135
JAC 8043	0.00033	0.00004	101.82	0.00356	0.00061	0.00001	68.00	0.00049
KEN 4002		0.00036	35.26	0.01262				
KEN 4003	0.00035	0.00090	84.38	0.07144		0.00077	90.67	0.06986
KEN 4004		0.00023	100.17	0.01869		0.00001	364.00	0.00377
KEN 4005	0.00039	0.00046	51.22	0.02836	0.00019	0.00036	50.90	0.01829
KEN 4006		0.00068	32.12	0.03350		0.00027	110.00	0.02920
KIL 8012	0.00077	0.00077	101.12	0.07694	0.00025	0.00055	46.81	0.02558
KIL 8013	0.00021	0.00023	53.59	0.01746	0.00002			
KIL 8014	0.00121	0.00040	97.94	0.02004		0.00012	112.45	0.01387
KIL 8015	0.00041	0.00013	79.07	0.01046		0.00000	38.00	0.00018
KIL 8016	0.00140	0.00043	92.27	0.02587	0.00053	0.00025	85.38	0.02100
KIL 8022	0.00176	0.00077	68.09	0.04316	0.00090	0.00010	50.81	0.00516
KIL 8023	0.00044	0.00050	63.39	0.04287	0.00007	0.00008	68.63	0.00552
KIL 8024	0.00068	0.00045	87.97	0.03239	0.00079	0.00011	72.94	0.00833
KIL 8025	0.00207	0.00074	74.72	0.05098	0.00026	0.00027	40.34	0.01072
KIL 8031	0.00013	0.00009	53.52	0.00394	0.00004			
KIL 8033	0.00027	0.00022	36.13	0.00759	0.00001			
KIL 8034	0.00130	0.00028	106.57	0.01816	0.00143	0.00103	26.45	0.02737
KIL 8041	0.00077	0.00032	43.44	0.00777	0.00087	0.00073	52.65	0.03866
KIL 8042	0.00104	0.00042	83.94	0.01920	0.00001	0.00004	114.96	0.00512
KIL 8043	0.00039	0.00019	80.20	0.01345	0.00009	0.00001	192.77	0.00100
KIL 8044	0.00247	0.00058	125.14	0.03845	0.00232	0.00029	15.75	0.00453
KIN 8011	0.00047	0.00017	49.73	0.00862	0.00061			
KIN 8012	0.00043	0.00008	103.93	0.00388	0.00031	0.00005	8.00	0.00041
KIN 8013	0.00016	0.00002	233.46	0.00536				
KIN 8014	0.00048	0.00007	44.67	0.00254		0.00009	53.00	0.00464
KIN 8015	0.00245	0.00112	108.97	0.11851	0.00293			
KIN 8022	0.00244	0.00051	80.38	0.04365	0.00161	0.00074	28.44	0.02114

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
KIN 8023	0.00185	0.00051	83.37	0.02411	0.00157			
KIN 8024	0.00154	0.00080	80.49	0.05082	0.00018			
KIN 8025	0.00405	0.00167	40.85	0.08721	0.00043	0.00055	35.61	0.01966
KIN 8041		0.00117	18.86	0.02200				
KIN 8042		0.00022	41.53	0.01867	0.00013			
KNY 8011	0.00022	0.00017	140.29	0.01794		0.00010	14.00	0.00134
KUL 8012	0.00201	0.00104	81.71	0.05391	0.00142	0.00039	41.68	0.01621
KUL 8013	0.00200	0.00210	52.48	0.08807	0.00152	0.00156	42.98	0.06687
KUL 8021	0.00438	0.00162	27.28	0.04564	0.00079	0.00044	7.00	0.00309
KUL 8022	0.00214	0.00107	73.15	0.05578	0.00037	0.00089	19.91	0.01775
KUL 8023	0.00118	0.00032	74.48	0.01063	0.00061	0.00030	15.00	0.00447
KUS 8002	0.00141	0.00114	94.26	0.12250				
KUS 8003	0.00274	0.00092	61.29	0.05550		0.00003	68.00	0.00227
KUS 8004	0.00107	0.00073	42.43	0.02543	0.00055	0.00072	23.36	0.01676
KUS 8006	0.00170	0.00057	69.08	0.01082	0.00139	0.00118	31.18	0.03684
KUS 8008	0.00052	0.00032	31.48	0.00460		0.00017	6.00	0.00104
KUS 8009	0.00146	0.00151	37.24	0.04252	0.00202	0.00090	28.97	0.02597
KUS 8010	0.00084	0.00050	96.51	0.03228	0.00004			
KUS 8034	0.00056	0.00019	74.95	0.01103		0.00004	87.08	0.00364
KUS 8042	0.00104	0.00077	56.65	0.04017				
KUS 8043	0.00105	0.00030	75.39	0.02037		0.00020	25.21	0.00512
KUS 8044	0.00111	0.00047	90.14	0.03620		0.00007	103.58	0.00730
KUS 8045	0.00168	0.00074	87.68	0.03942	0.00084	0.00040	272.46	0.10942
LAF 8013	0.00029	0.00031	58.35	0.01580		0.00002	49.00	0.00094
LAF 8014	0.00019	0.00017	176.81	0.02337		0.00002	81.00	0.00164
LAF 8015	0.00216	0.00046	37.21	0.01240	0.00206	0.00002	75.23	0.00159
LAF 8021	0.00002	0.00001	8.00	0.00008				
LAF 8022	0.00232	0.00064	59.13	0.03580	0.00115	0.00205	23.45	0.04816
LAF 8023	0.00036	0.00039	68.49	0.02989				
LAF 8025	0.00013	0.00007	17.67	0.00128				
LAF 8026	0.00187	0.00074	81.20	0.04624	0.00169	0.00072	33.69	0.02415
LAK 8011	0.00019	0.00003	32.00	0.00181	0.00016	0.00006	19.00	0.00107
LAK 8012	0.00005	0.00006	60.88	0.00309				
LAK 8013	0.00011	0.00021	135.87	0.02658	0.00016	0.00000	85.00	0.00037
LAK 8015	0.00003	0.00001	27.96	0.00035				
LAK 8021	0.00019	0.00006	60.15	0.00442	0.00010			
LAK 8022	0.00004	0.00002	60.68	0.00118				
LAK 8023	0.00009	0.00003	57.65	0.00190		0.00000		
LAK 8024	0.00143	0.00059	62.23	0.03255	0.00110	0.00008	107.10	0.00848
LAK 8025	0.00001	0.00000	136.00	0.00047				
LAU 8011	0.00144	0.00127	78.85	0.08953	0.00081	0.00027	27.49	0.00740
LAU 8012	0.00083	0.00035	75.20	0.01523	0.00094	0.00024	78.54	0.01872
LAU 8014	0.00104	0.00025	53.95	0.01189	0.00037	0.00035	16.72	0.00577
LAU 8021	0.00171	0.00078	91.07	0.05505	0.00075	0.00064	79.46	0.05076
LAU 8023	0.00079	0.00073	64.66	0.04997	0.00110	0.00087	74.78	0.06539
LAU 8024	0.00009	0.00012	114.45	0.01480	0.00015			

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
LAU 8025	0.00071	0.00084	92.91	0.06272	0.00105	0.00056	80.83	0.04520
LAU 8034	0.00159	0.00116	72.04	0.09416	0.00142	0.00004	91.43	0.00375
LAU 8035	0.00144	0.00109	123.00	0.08036	0.00166	0.00128	16.69	0.02128
LAU 8044	0.00009	0.00006	145.96	0.00604				
LAW 8014	0.00106	0.00036	133.79	0.04047	0.00049	0.00003	116.40	0.00371
LAW 8015	0.00023	0.00024	44.87	0.00890		0.00000	51.00	0.00018
LAW 8016	0.00079	0.00093	55.22	0.05573	0.00054	0.00016	33.95	0.00534
LAW 8023	0.00074	0.00094	72.98	0.06122	0.00080	0.00051	102.73	0.05270
LAW 8024	0.00122	0.00075	107.43	0.05493	0.00042	0.00044	60.66	0.02668
LAW 8025	0.00082	0.00110	81.77	0.08155	0.00026	0.00087	84.05	0.07346
LAW 8033	0.00088	0.00029	101.37	0.02923	0.00171	0.00134	83.36	0.11144
LAW 8039	0.00030	0.00016	95.04	0.01316		0.00003	98.00	0.00261
LCE 8003	0.00060	0.00074	39.41	0.02090	0.00047	0.00027	18.34	0.00488
LCE 8005	0.00047	0.00023	57.44	0.01243	0.00044	0.00006	556.13	0.03497
LCE 8010	0.00059	0.00047	91.97	0.03263	0.00106	0.00038	138.14	0.05278
LCE 8012	0.00029	0.00061	64.74	0.03965	0.00171	0.00024	20.94	0.00502
LCE 8032	0.00211	0.00129	38.72	0.05027		0.00006	102.62	0.00600
LCE 8033	0.00177	0.00049	44.64	0.02295		0.00077	85.79	0.06631
LCE 8034	0.00155	0.00053	159.52	0.02644	0.00260	0.00099	38.49	0.03798
LCE 8035	0.00039	0.00006	112.56	0.00281		0.00004	27.00	0.00113
LCE 8042	0.00064	0.00106	95.56	0.14059	0.00056	0.00087	131.04	0.11401
LCE 8043	0.00108	0.00078	21.34	0.02096	0.00033	0.00009	91.86	0.00863
LCE 8044	0.00111	0.00074	72.40	0.04405		0.00029	150.90	0.04450
LCE 8045	0.00088	0.00069	52.68	0.02312	0.00051	0.00019	14.82	0.00280
LCE 8046	0.00106	0.00081	51.10	0.04191	0.00010	0.00096	27.69	0.02646
LCU 8051	0.00281	0.00108	59.61	0.05653	0.00219			
LEH 4002		0.00049	95.34	0.03054				
LEH 4003		0.00008	145.00	0.00782				
LEH 4004	0.00042	0.00054	77.54	0.04146				
LEH 4006		0.00027	89.33	0.01551		0.00003	104.00	0.00319
LEH 4007		0.00017	83.00	0.01371				
LEO 8003	0.00209	0.00158	114.76	0.12987		0.00042	60.36	0.02546
LEO 8004	0.00159	0.00219	74.42	0.16494	0.00049	0.00010	65.85	0.00640
LEO 8005	0.00134	0.00155	63.60	0.08730	0.00150	0.00072	30.31	0.02195
LEO 8006	0.00075	0.00029	76.99	0.01843	0.00018	0.00005	123.50	0.00590
LEO 8008	0.00064	0.00034	93.58	0.02146				
LEO 8009	0.00003	0.00007	194.81	0.00615	0.00002	0.00005	69.11	0.00377
LEO 8032	0.00060	0.00021	83.53	0.01064	0.00064	0.00054	71.17	0.03841
LEO 8033	0.00034	0.00040	53.09	0.02325		0.00014	122.18	0.01726
LEO 8034	0.00080	0.00091	59.06	0.05782		0.00125	27.96	0.03493
LEO 8041	0.00228	0.00228	62.33	0.14603	0.00081	0.00010	62.67	0.00641
LEO 8042	0.00040	0.00033	44.53	0.01746	0.00091	0.00038	62.36	0.02348
LEO 8043	0.00123	0.00028	137.06	0.01765	0.00044	0.00018	58.00	0.01053
LEO 8044	0.00097	0.00015	239.89	0.02436	0.00061	0.00023	160.52	0.03712
LEO 8045	0.00068	0.00040	76.73	0.03070	0.00047			
LEV 8002	0.00267	0.00110	81.12	0.07731	0.00100	0.00136	52.46	0.07151

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
LEV 8006	0.00126	0.00069	80.48	0.04455	0.00124	0.00048	32.58	0.01576
LEV 8008	0.00178	0.00115	96.01	0.07985	0.00220	0.00017	82.75	0.01446
LEV 8011	0.00058	0.00029	77.11	0.02693	0.00052	0.00013	43.00	0.00578
LEV 8012	0.00141	0.00091	90.30	0.07877		0.00010	277.00	0.02778
LEV 8013	0.00040	0.00029	98.25	0.02433	0.00082	0.00021	109.39	0.02251
LEV 8016	0.00126	0.00057	150.99	0.02231	0.00100	0.00046	36.00	0.01658
LIB 4003	0.00085	0.00134	67.88	0.08977				
LIB 4004	0.00033	0.00034	58.00	0.01948				
LIB 4005	0.00047	0.00024	6.00	0.00291		0.00102	41.17	0.04211
LIB 4007	0.00060	0.00119	148.00	0.17622	0.00084	0.00058	38.26	0.02211
LIB 4009	0.00055	0.00030	23.00	0.00302		0.00028	270.00	0.07436
LIT 8001	0.00127	0.00033	156.52	0.03515	0.00098			
LIT 8004	0.00141	0.00016	124.80	0.02508	0.00060	0.00002	88.00	0.00196
LOC 8012	0.00209	0.00064	64.17	0.01576	0.00006			
LOC 8014	0.00086	0.00030	36.82	0.01096	0.00069	0.00001	858.00	0.00478
LOC 8033	0.00026	0.00010	21.00	0.00215	0.00026	0.00002	54.00	0.00101
LOI 8001	0.00292	0.00037	80.51	0.02505	0.00169	0.00052	161.24	0.08432
LUM 8014	0.00078	0.00037	107.18	0.04317	0.00097	0.00000	355.00	0.00057
LUM 8021	0.00114	0.00146	62.23	0.09114		0.00075	101.93	0.07623
LUM 8022	0.00099	0.00025	66.68	0.02118	0.00097	0.00028	69.38	0.01922
LUM 8024	0.00116	0.00047	128.91	0.03928	0.00011	0.00053	88.47	0.04708
MAD 8014	0.00014	0.00005	84.76	0.00388	0.00013	0.00002	115.87	0.00254
MAD 8015	0.00132	0.00031	105.30	0.02911	0.00011	0.00042	33.72	0.01424
MAD 8016	0.00018	0.00007	68.39	0.00368		0.00003	26.00	0.00078
MAD 8018	0.00241	0.00110	68.80	0.07374	0.00108	0.00002	70.50	0.00174
MAD 8021	0.00046	0.00039	223.14	0.02598	0.00046	0.00006	142.48	0.00856
MAD 8022	0.00050	0.00054	131.92	0.04273		0.00043	68.02	0.02908
MAD 8024	0.00009	0.00003	68.97	0.00222	0.00009	0.00001	131.44	0.00141
MAD 8026	0.00012	0.00010	148.76	0.01702	0.00003	0.00018	71.37	0.01295
MAD 8031	0.00168	0.00066	133.86	0.05565	0.00068	0.00026	101.25	0.02603
MAD 8032	0.00101	0.00066	142.57	0.11149	0.00067	0.00019	139.97	0.02668
MAD 8037	0.00132	0.00056	74.62	0.03142		0.00016	57.55	0.00930
MAI 8013	0.00066	0.00030	81.52	0.01958	0.00026	0.00051	78.08	0.03968
MAR 8001	0.00013	0.00003	104.00	0.00370	0.00010	0.00011	117.46	0.01272
MAR 8002	0.00118	0.00030	80.07	0.01904	0.00128	0.00117	85.77	0.10047
MAR 8004	0.00014	0.00008	69.17	0.00472		0.00012	14.50	0.00172
MAR 8005	0.00008	0.00007	104.03	0.00404	0.00000	0.00022	56.38	0.01245
MAR 8006	0.00016	0.00009	89.16	0.00775				
MAR 8008	0.00042	0.00020	99.04	0.01672	0.00023	0.00004	114.83	0.00494
MAR 8009	0.00114	0.00028	89.61	0.02115		0.00041	35.01	0.01444
MAR 8010	0.00036	0.00038	52.75	0.02191	0.00029	0.00002	171.00	0.00388
MAR 8011	0.00082	0.00008	149.50	0.00488				
MAR 8012	0.00031	0.00005	100.86	0.00605	0.00031	0.00002	126.50	0.00312
MAR 8013	0.00113	0.00032	123.72	0.04409	0.00021			
MAR 8016	0.00057	0.00034	144.66	0.01881	0.00045			
MAR 8017	0.00042	0.00041	133.97	0.04925	0.00088	0.00009	88.00	0.00823

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MAR 8018	0.00124	0.00042	88.03	0.02276	0.00124	0.00013	126.66	0.01659
MAS 4006	0.00022	0.00004	102.00	0.00433				
MAY 8013	0.00053	0.00038	60.85	0.02041	0.00083			
MAY 8014	0.00059	0.00045	64.93	0.01770	0.00073	0.00023	61.90	0.01434
MAY 8015	0.00437	0.00209	50.25	0.09899	0.00699	0.00165	25.54	0.04213
MAY 8022	0.00152	0.00100	39.21	0.04314		0.00046	135.64	0.06219
MAY 8023	0.00093	0.00085	64.62	0.05909	0.00055	0.00005	84.50	0.00444
MAY 8024	0.00052	0.00030	72.16	0.01418	0.00188	0.00006	72.77	0.00405
MAY 8034	0.00376	0.00110	68.16	0.06274	0.00468	0.00065	33.18	0.02141
MAY 8036	0.00113	0.00108	15.50	0.01638	0.00096	0.00051	16.08	0.00817
MAY 8043	0.00085	0.00039	130.04	0.03176	0.00204	0.00047	50.02	0.02345
MAY 8044	0.00079	0.00048	127.56	0.06925	0.00044	0.00021	90.63	0.01886
MAY 8045	0.00012	0.00020	97.12	0.00624				
MCL 4001		0.00017	56.39	0.00786		0.00000	96.00	0.00004
MCL 4002	0.00057	0.00131	28.26	0.03677		0.00037	21.35	0.00800
MCL 4003		0.00010	145.30	0.00892		0.00061	9.82	0.00601
MCL 4004	0.00027	0.00026	18.50	0.00498				
MCL 4006		0.00060	18.00	0.01085		0.00000	180.00	0.00072
MCL 4007		0.00148	184.80	0.33918				
MCL 4008		0.00055	77.78	0.03748				
MCL 4010		0.00038	36.82	0.01399	0.00032	0.00010	10.00	0.00102
MDF 8012	0.00128	0.00058	108.15	0.05896	0.00048	0.00025	22.30	0.00549
MDF 8014	0.00104	0.00030	146.07	0.02124		0.00016	154.42	0.02501
MDF 8021	0.00242	0.00087	120.05	0.06121	0.00024	0.00005	120.13	0.00645
MDF 8023	0.00073	0.00057	99.69	0.04389	0.00161	0.00207	94.45	0.19536
MDF 8024	0.00101	0.00095	100.56	0.05945		0.00038	74.05	0.02797
MDS 4003		0.00063	82.50	0.05215				
MDS 4012		0.00042	87.50	0.03622				
MEA 8011	0.00011	0.00017	68.51	0.01019	0.00027	0.00011	233.19	0.02543
MEA 8012	0.00026	0.00006	83.22	0.00510	0.00033			
MEA 8013	0.00150	0.00060	77.46	0.03420	0.00171	0.00078	23.44	0.01826
MEA 8015	0.00008	0.00005	142.27	0.00312	0.00006			
MEA 8016	0.00042	0.00019	98.63	0.01100	0.00027	0.00007	78.99	0.00569
MEA 8021	0.00117	0.00030	66.01	0.01068	0.00065	0.00055	22.14	0.01223
MEA 8024	0.00178	0.00188	54.15	0.09269	0.00199	0.00010	501.02	0.05165
MEA 8025	0.00049	0.00014	54.51	0.00677	0.00177	0.00040	90.31	0.03602
MEC 8004	0.00092	0.00033	93.50	0.02350		0.00048	63.34	0.03061
MIN 8011	0.00048	0.00023	115.79	0.03279		0.00002	43.00	0.00079
MIN 8012	0.00032	0.00021	172.77	0.01324	0.00004	0.00005	47.75	0.00224
MIN 8013	0.00325	0.00128	43.64	0.02221	0.00117	0.00004	86.84	0.00311
MIN 8015	0.00190	0.00025	164.98	0.01536	0.00226	0.00043	63.28	0.02735
MIN 8021	0.00004	0.00001	13.00	0.00024				
MIN 8022	0.00146	0.00025	44.44	0.01073	0.00289	0.00047	18.00	0.00837
MIN 8023	0.00023	0.00013	125.74	0.01755		0.00006	143.53	0.00880
MIN 8024	0.00065	0.00017	177.97	0.02511	0.00005	0.00028	7.75	0.00220
MIN 8025	0.00159	0.00048	52.34	0.02802	0.00073	0.00132	19.50	0.02571

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
MIN 8026	0.00182	0.00016	87.04	0.01271				
MNT 4004		0.00035	142.94	0.01842		0.00018	155.90	0.02860
MNT 4005		0.00056	134.55	0.05502		0.00029	91.55	0.02696
MNT 4006	0.00038	0.00034	314.46	0.03677		0.00021	506.00	0.10452
MNT 4009		0.00023	131.40	0.01339		0.00001	245.33	0.00264
MNT 4010	0.00037	0.00042	79.77	0.02655				
MNT 4012		0.00053	233.16	0.04186		0.00011	176.67	0.01856
MNT 4015		0.00064	34.86	0.02994		0.00020	8.00	0.00161
MOG 4001		0.00073	45.50	0.03292		0.00027	161.00	0.04357
MOG 4002		0.00100	53.03	0.05648		0.00053	48.08	0.02558
MOG 4006	0.00083	0.00026	46.70	0.01190		0.00025	5.00	0.00123
MOG 4011		0.00051	45.50	0.02331				
MON 8002	0.00105	0.00135	79.93	0.10034	0.00096	0.00033	120.68	0.03991
MON 8003	0.00130	0.00066	77.61	0.02157		0.00009	150.30	0.01304
MON 8004	0.00104	0.00052	91.74	0.03113		0.00004	41.55	0.00150
MOT 8001	0.00061	0.00049	85.94	0.03831	0.00024	0.00024	94.70	0.02310
MOT 8002	0.00042	0.00018	183.37	0.01148		0.00012	148.41	0.01831
MOT 8003	0.00065	0.00043	69.29	0.02392	0.00008	0.00021	87.79	0.01852
MOY 4002	0.00045	0.00063	59.84	0.04838				
MOY 4003	0.00019	0.00028	55.00	0.01802		0.00014	40.00	0.00568
MOY 4005	0.00030	0.00001	361.52	0.00264				
MOY 4009	0.00052	0.00054	71.15	0.03871				
MRO 8012	0.00167	0.00084	97.12	0.07311	0.00118	0.00057	113.33	0.06500
MRO 8013	0.00115	0.00030	84.95	0.02439	0.00118	0.00016	38.69	0.00621
MRO 8022	0.00111	0.00128	62.81	0.06208	0.00082	0.00075	85.92	0.06483
MRO 8023	0.00127	0.00072	145.59	0.10133	0.00063	0.00131	94.34	0.12342
MRO 8024	0.00184	0.00048	74.27	0.03475	0.00213	0.00101	64.75	0.06520
MSD 8001	0.00111	0.00082	76.56	0.05759	0.00091	0.00002	63.00	0.00110
MTL 8013	0.00234	0.00078	97.41	0.03105		0.00004	109.79	0.00476
MTL 8014	0.00017	0.00012	104.43	0.01028		0.00005	83.26	0.00451
MTL 8015	0.00098	0.00051	114.82	0.04669	0.00057	0.00025	162.93	0.04105
MTL 8022	0.00070	0.00024	109.43	0.01181	0.00081			
MTL 8024	0.00012	0.00008	99.59	0.00580	0.00028	0.00010	62.97	0.00619
NBS 8011	0.00070	0.00051	68.66	0.02203	0.00266	0.00004	51.43	0.00229
NBS 8012	0.00052	0.00025	112.89	0.02898	0.00002	0.00011	232.80	0.02492
NBS 8013	0.00215	0.00048	39.48	0.01477				
NBS 8021	0.00034	0.00002	95.00	0.00379	0.00008	0.00001	67.00	0.00072
NBS 8023	0.00021	0.00001	109.34	0.00393	0.00016	0.00023	87.21	0.02027
NED 8013	0.00060	0.00029	52.15	0.01435	0.00102	0.00013	69.85	0.00931
NED 8014	0.00026	0.00033	79.22	0.01981	0.00015	0.00014	91.12	0.01280
NED 8015	0.00148	0.00089	83.19	0.06818	0.00142	0.00029	85.60	0.02501
NED 8016	0.00125	0.00059	147.80	0.06662	0.00116	0.00043	77.65	0.03338
NED 8022	0.00110	0.00084	26.80	0.02081		0.00000	231.00	0.00092
NED 8024	0.00057	0.00033	51.39	0.01363	0.00077	0.00004	67.89	0.00238
NED 8025	0.00277	0.00065	107.68	0.06845	0.00101	0.00012	102.18	0.01175
NEV 8001	0.00182	0.00047	81.59	0.03734		0.00005	93.79	0.00433

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
NEW 8011	0.00044	0.00018	135.78	0.01834		0.00005	41.00	0.00186
NEW 8013	0.00207	0.00045	99.55	0.03237				
NEW 8014	0.00100	0.00062	92.00	0.04881		0.00005	35.92	0.00174
NEW 8023	0.00061	0.00032	92.23	0.02734		0.00031	43.08	0.01336
NEW 8025	0.00066	0.00031	159.08	0.04196		0.00018	35.57	0.00623
NEW 8032	0.00015	0.00024	81.70	0.01998				
NEW 8033	0.00078	0.00061	81.15	0.03393	0.00065			
NEW 8034	0.00130	0.00121	57.43	0.06839	0.00086	0.00004	88.53	0.00331
NEW 8041	0.00212	0.00062	76.35	0.02987	0.00190	0.00086	76.29	0.06531
NEW 8042	0.00108	0.00056	98.59	0.05165	0.00068	0.00049	40.11	0.01968
NEW 8044	0.00098	0.00048	107.66	0.03597	0.00055	0.00141	11.10	0.01566
NIN 4001		0.00042	231.06	0.03644				
NIN 4002		0.00156	31.12	0.04910	0.00111	0.00073	32.00	0.02349
NIN 4003	0.00134	0.00157	60.38	0.05305	0.00066			
NIN 4004		0.00042	173.70	0.03815				
NIN 4005	0.00080	0.00109	73.64	0.06603				
NIN 4006	0.00295	0.00002	192.58	0.00471	0.00127	0.00250	17.33	0.04327
NIT 8007	0.00233	0.00065	90.21	0.07520	0.00134	0.00012	149.13	0.01864
NOF 4003	0.00056	0.00026	87.33	0.01972	0.00035	0.00002	187.98	0.00419
NOF 4004		0.00111	76.92	0.11608		0.00057	50.00	0.02856
NOF 4010	0.00045	0.00071	71.59	0.05470				
NOT 8011	0.00004	0.00002	245.25	0.00130	0.00003	0.00001	73.00	0.00049
NOT 8013	0.00109	0.00049	34.95	0.01806	0.00003	0.00003	178.00	0.00489
NOT 8014	0.00123	0.00046	152.51	0.03799		0.00037	9.00	0.00330
NOT 8016	0.00041	0.00042	61.02	0.02571				
NOT 8021	0.00110	0.00063	102.78	0.04143				
NOT 8022	0.00059	0.00049	56.75	0.01040	0.00080	0.00000		
NOT 8023	0.00004	0.00003	61.39	0.00210				
NOT 8024	0.00178	0.00105	119.79	0.09724	0.00113	0.00041	112.08	0.04613
NRB 8012	0.00039	0.00025	72.76	0.02435	0.00081	0.00000	68.00	0.00003
NRB 8013	0.00288	0.00030	70.30	0.01483	0.00178	0.00048	5.00	0.00241
NRB 8014	0.00219	0.00068	112.39	0.05665	0.00297	0.00153	33.53	0.05145
NRB 8015	0.00117	0.00061	88.15	0.03949	0.00261			
NRB 8022	0.00258	0.00119	89.43	0.06005	0.00064	0.00005	206.00	0.00992
NRP 4001	0.00029	0.00029	41.00	0.01204				
NRP 4002	0.00047	0.00035	137.00	0.04846				
NRP 4003	0.00104	0.00172	45.89	0.08996		0.00003	125.00	0.00378
NRP 4004	0.00040							
NRP 4007	0.00068	0.00051	43.64	0.01042		0.00131	109.83	0.14381
NRP 4009		0.00025	43.02	0.01111		0.00001	237.00	0.00255
NRP 4010	0.00085	0.00147	38.83	0.04329	0.00060	0.00421	37.26	0.15705
NRP 4012	0.00019	0.00015	61.90	0.00922				
NRP 4014	0.00046	0.00043	92.82	0.02491	0.00095			
NRP 4015	0.00040	0.00039	30.22	0.01171				
NUT 4001		0.00008	191.31	0.00723				
NUT 4002		0.00006	257.29	0.01192	0.00015	0.00041	72.38	0.02947

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
OAK 4004	0.00179	0.00061	150.90	0.04071	0.00293	0.00118	43.68	0.05162
OAK 4008	0.00222	0.00216	68.59	0.10917	0.00146	0.00148	23.81	0.03519
ORA 4001		0.00084	100.34	0.03252				
ORA 4002		0.00034	137.44	0.02313		0.00024	118.43	0.02847
ORA 4003		0.00071	7.00	0.00500				
ORA 4006		0.00091	74.37	0.06782				
PAR 4002	0.00018							
PAR 4003		0.00010	216.88	0.01240				
PAR 4006		0.00015	78.27	0.01318	0.00015	0.00040	84.75	0.03414
PAS 4003	0.00070	0.00070	73.70	0.03265				
PAS 4007		0.00070	54.83	0.03844				
PAS 4008	0.00017	0.00021	35.12	0.00829		0.00008	6.00	0.00051
PAS 4011		0.00035	83.88	0.02030		0.00087	59.72	0.05222
PAS 4016	0.00048	0.00115	59.01	0.06618		0.00046	9.00	0.00416
PAS 4020	0.00066	0.00096	74.00	0.06564				
PAT 4003	0.00041	0.00054	89.80	0.04903		0.00091	80.70	0.07320
PAT 4008		0.00042	113.50	0.02505		0.00108	27.90	0.03018
PAT 4010		0.00007	391.13	0.02599	0.00008			
PAT 4011	0.00043	0.00043	9.50	0.00818				
PAT 4012	0.00046	0.00052	29.38	0.01746	0.00040			
PAT 4016						0.00019	40.29	0.00766
PEH 8001	0.00028	0.00014	43.31	0.00607		0.00014	33.39	0.00468
PEH 8004	0.00006	0.00004	66.19	0.00282		0.00001	60.00	0.00060
PEH 8013	0.00164	0.00070	49.64	0.02179	0.00084			
PEH 8015	0.00396	0.00082	52.00	0.03991		0.00008	94.20	0.00799
PEH 8022	0.00012	0.00005	32.21	0.00188				
PEH 8025	0.00007	0.00002	11.00	0.00018		0.00001	37.00	0.00031
PEK 8018	0.00043	0.00027	148.79	0.03679	0.00026	0.00053	50.20	0.02642
PEK 8021	0.00055	0.00007	88.96	0.00360	0.00041	0.00002	168.00	0.00374
PEK 8022	0.00134	0.00047	59.28	0.02088				
PEK 8023	0.00103	0.00105	89.28	0.07620		0.00069	36.87	0.02554
PEK 8026	0.00121	0.00040	148.11	0.03507				
PEK 8034		0.00000	107.56	0.00029	0.00012			
PEK 8035	0.00090	0.00089	113.77	0.05819	0.00104	0.00039	109.35	0.04234
PEK 8036	0.00030	0.00021	184.43	0.03676	0.00012	0.00008	98.22	0.00786
PIE 8011	0.00006	0.00009	82.40	0.00784	0.00004	0.00001	206.00	0.00213
PIE 8013	0.00104	0.00036	49.80	0.01542	0.00010	0.00019	33.32	0.00618
PIE 8014	0.00225	0.00072	69.75	0.05139	0.00063	0.00009	100.61	0.00937
PIE 8015	0.00083	0.00029	109.64	0.01346	0.00030	0.00004	127.80	0.00463
PIE 8022	0.00059	0.00018	72.64	0.01529	0.00012	0.00009	38.37	0.00330
PIE 8023	0.00164	0.00061	65.59	0.02577		0.00002	171.29	0.00382
PIN 4001		0.00069	416.48	0.07134		0.00002	72.00	0.00166
PIN 4002		0.00060	109.00	0.06557	0.00008			
PLA 4004		0.00008	81.00	0.00068				
PLA 4007	0.00055							
PLA 4008	0.00034	0.00052	23.00	0.01187				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
PLA 4010		0.00063	77.25	0.04234		0.00065	62.02	0.04021
PLA 4012	0.00015	0.00052	207.93	0.01965				
PLA 4013	0.00185	0.00032	84.62	0.01420		0.00025	5.00	0.00124
PLI 8003	0.00159	0.00057	116.08	0.03994	0.00102	0.00021	74.14	0.01582
PLI 8004	0.00117	0.00121	95.10	0.07267		0.00029	216.65	0.06269
PLI 8005	0.00114	0.00023	56.42	0.00614		0.00010	155.73	0.01512
PLI 8007	0.00089	0.00069	100.60	0.05460		0.00006	139.89	0.00807
PLI 8008	0.00110	0.00051	86.91	0.04167	0.00005	0.00035	71.56	0.02501
PLI 8010	0.00042	0.00030	49.80	0.01154				
PLI 8011	0.00011	0.00008	49.32	0.00342		0.00012	82.72	0.01014
PLI 8012	0.00032	0.00010	45.60	0.00300	0.00025			
POH 8012	0.00006	0.00001	80.77	0.00172				
POH 8013	0.00056	0.00027	60.80	0.01980	0.00054	0.00003	147.02	0.00480
POH 8015	0.00064	0.00024	34.86	0.00972				
POH 8021	0.00027	0.00004	96.75	0.00147		0.00008	26.00	0.00199
POH 8022	0.00109	0.00037	88.63	0.02245	0.00001	0.00017	104.11	0.01724
POH 8023	0.00234	0.00058	158.46	0.03658				
POH 8024	0.00058	0.00059	40.08	0.01575	0.00006	0.00009	68.05	0.00623
POH 8026	0.00036	0.00026	77.88	0.00839				
POL 4001					0.00142	0.00216	78.33	0.16929
POL 4003		0.00148	98.45	0.14543		0.00047	180.00	0.08411
POL 4004		0.00020	68.00	0.02754		0.00041	174.00	0.07085
POL 4005		0.00058	28.50	0.01668	0.00055	0.00055	191.00	0.10483
POL 4006		0.00081	13.84	0.01119		0.00041	201.00	0.08184
POL 4010		0.00056	40.13	0.02237		0.00064	201.00	0.12928
POL 4012		0.00026	46.00	0.00841	0.00024	0.00084	174.71	0.14679
POR 8021	0.00032	0.00008	31.98	0.00251	0.00017	0.00019	62.59	0.01216
PRI 4001		0.00008	226.67	0.00314				
RAV 8003	0.00086	0.00058	43.10	0.02941		0.00003	431.70	0.01134
RFL 8011	0.00111	0.00018	100.96	0.01326	0.00171	0.00009	68.84	0.00633
RFL 8012	0.00332	0.00051	51.71	0.02604	0.00210	0.00103	17.05	0.01762
RFL 8014	0.00097	0.00053	67.65	0.02622	0.00054	0.00002	466.09	0.00835
RFL 8021	0.00013	0.00011	83.14	0.00689				
RFL 8022	0.00003	0.00001	94.50	0.00104				
RFL 8023	0.00047	0.00013	137.93	0.00550	0.00031	0.00003	17.20	0.00044
RFL 8025	0.00018	0.00010	65.64	0.00359	0.00016	0.00001	18.00	0.00024
RFL 8032	0.00152	0.00072	72.01	0.03340	0.00014			
RFL 8034	0.00198	0.00149	46.29	0.06455	0.00102	0.00046	22.36	0.01036
RFL 8035	0.00200	0.00137	42.69	0.06029	0.00023			
RFL 8042	0.00022	0.00007	15.00	0.00146				
RFL 8044	0.00010	0.00001	54.00	0.00041				
RGW 4004		0.00006	107.00	0.00134				
RGW 4005	0.00019	0.00000	280.50	0.00219				
RGW 4006	0.00029	0.00015	88.83	0.00727				
RGW 4007		0.00036	95.00	0.03427		0.00088	105.68	0.09300
RGW 4009		0.00022	84.72	0.01877				

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
RGW 4012		0.00028	119.88	0.01813				
RGW 4013		0.00016	46.26	0.00602		0.00030	31.45	0.00936
RGW 4014		0.00010	102.50	0.00831		0.00032	104.31	0.03288
RGW 4015						0.00004	125.00	0.00537
RIS 4004	0.00041					0.00017	32.00	0.00553
RIS 4005		0.00027	11.00	0.00294		0.00031	33.00	0.01036
RIV 8006	0.00326	0.00086	70.60	0.05850	0.00071	0.00088	30.83	0.02724
RSL 4003	0.00079	0.00043	78.67	0.03386		0.00074	219.46	0.16325
RSL 4006		0.00157	103.11	0.16146		0.00055	171.00	0.09344
RSL 4007		0.00057	371.62	0.12168		0.00047	230.26	0.10823
RSL 4008	0.00072	0.00090	85.96	0.07398		0.00068	184.00	0.12589
RUN 8001	0.00090	0.00034	106.78	0.01449	0.00027	0.00006	116.15	0.00721
RUN 8003	0.00059	0.00041	104.43	0.03428		0.00015	154.84	0.02280
RUN 8004	0.00096	0.00018	91.18	0.01730		0.00003	80.91	0.00222
RUN 8005	0.00072	0.00041	142.43	0.02914	0.00127	0.00006	125.25	0.00813
RVR 8011	0.00200	0.00107	56.19	0.05534		0.00110	75.20	0.08237
RVR 8022	0.00114	0.00164	62.87	0.10572	0.00023	0.00062	48.98	0.03021
RVR 8031	0.00090	0.00078	93.07	0.08001	0.00138	0.00049	118.23	0.05783
SAD 8002	0.00253	0.00144	54.18	0.04421	0.00119	0.00062	58.75	0.03664
SAD 8003	0.00073	0.00045	116.37	0.03871	0.00195	0.00008	126.00	0.00968
SAD 8004	0.00030	0.00009	163.18	0.00324		0.00002	169.00	0.00283
SAD 8006	0.00026	0.00022	60.71	0.01385				
SAD 8008	0.00157	0.00065	59.79	0.03864	0.00093	0.00095	106.42	0.10059
SAD 8032	0.00135	0.00062	56.12	0.03453	0.00005	0.00000	110.00	0.00018
SAD 8033	0.00018	0.00007	74.39	0.00644		0.00005	106.00	0.00481
SAD 8043	0.00156	0.00053	55.42	0.02807	0.00095	0.00051	19.68	0.01012
SAD 8044	0.00193	0.00102	113.24	0.08095	0.00202	0.00132	12.00	0.01590
SAD 8045	0.00148	0.00066	37.98	0.01923	0.00085	0.00058	269.74	0.15695
SDH 8021	0.00090	0.00064	60.73	0.03318	0.00095	0.00001	218.00	0.00217
SDH 8023	0.00137	0.00084	55.16	0.02451	0.00070	0.00020	43.02	0.00860
SDH 8024	0.00125	0.00083	63.93	0.03290	0.00067	0.00080	35.26	0.02826
SDH 8025	0.00112	0.00097	103.28	0.09314	0.00120	0.00092	112.64	0.10410
SDH 8026	0.00208	0.00087	67.62	0.04871	0.00059	0.00061	83.33	0.05098
SDH 8031	0.00199	0.00057	138.44	0.04389	0.00328	0.00119	58.63	0.06977
SDH 8033	0.00056	0.00019	97.72	0.01603	0.00056			
SDH 8034	0.00048	0.00060	68.68	0.02592	0.00072	0.00038	34.34	0.01315
SDH 8035	0.00036	0.00047	112.19	0.04545		0.00001	88.00	0.00105
SMV 8011	0.00033	0.00019	125.85	0.00790	0.00032	0.00000		
SMV 8012	0.00078	0.00028	64.07	0.00648	0.00067			
SMV 8013	0.00092	0.00102	50.71	0.04201	0.00100	0.00024	46.79	0.01140
SMV 8014	0.00070	0.00046	59.04	0.03868	0.00051			
SMV 8021	0.00138	0.00035	50.01	0.01030		0.00012	97.26	0.01161
SMV 8022	0.00143	0.00066	25.70	0.01733		0.00001	323.00	0.00334
SMV 8023	0.00054	0.00058	48.42	0.01499	0.00008	0.00010	24.88	0.00260
SMV 8024	0.00087	0.00033	37.48	0.01267	0.00109	0.00046	22.48	0.01028
SMV 8025	0.00054	0.00044	47.51	0.01467		0.00012	60.03	0.00693

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
SOH 8022	0.00150	0.00056	100.93	0.04714	0.00071	0.00002	166.17	0.00351
SOO 4004	0.00048	0.00057	74.10	0.05188		0.00053	76.71	0.04033
SOO 4011		0.00013	251.89	0.03476		0.00001	280.38	0.00324
SOO 4012	0.00032	0.00035	71.33	0.02655		0.00049	85.95	0.04198
SOP 4007		0.00044	42.88	0.02005	0.00028			
SOP 4008		0.00049	143.00	0.06984				
SOP 4010								
SOS 8015	0.00200	0.00065	64.61	0.03737	0.00063	0.00064	54.48	0.03495
SOS 8016	0.00547	0.00197	60.38	0.12723	0.00155	0.00009	209.39	0.01850
SOS 8025	0.00206	0.00113	76.54	0.08468		0.00010	236.85	0.02310
SPF 8012	0.00495	0.00183	96.55	0.08153	0.00139	0.00155	42.81	0.06620
SPF 8014	0.00013	0.00029	40.92	0.01176	0.00003	0.00010	174.30	0.01679
SPF 8015	0.00017	0.00010	74.71	0.00910	0.00007	0.00001	230.44	0.00293
SPF 8016	0.00018	0.00002	97.00	0.00536		0.00009	224.31	0.01991
SPF 8023	0.00025	0.00028	55.61	0.01552	0.00003	0.00026	98.14	0.02586
SPF 8024	0.00051	0.00018	192.74	0.00883		0.00005	141.00	0.00758
SPF 8025	0.00162	0.00073	58.72	0.02639	0.00253	0.00023	78.34	0.01833
STL 8011	0.00670	0.00456	21.12	0.10480	0.00279	0.00003	234.46	0.00653
STP 8001	0.00170	0.00087	53.11	0.02855	0.00276	0.00136	66.39	0.09055
STP 8002	0.00228	0.00071	95.01	0.02554	0.00245	0.00007	325.87	0.02231
STS 4003	0.00038	0.00032	194.00	0.06165				
STS 4005		0.00039	98.97	0.03381				
STS 4010	0.00087	0.00062	124.98	0.07707				
SUN 8011	0.00115	0.00024	83.20	0.00695	0.00023	0.00075	80.73	0.06076
SUN 8013	0.00033	0.00013	241.51	0.00757		0.00007	215.85	0.01615
SUN 8021	0.00254	0.00051	55.14	0.01733	0.00118	0.00005	97.71	0.00471
SUN 8022	0.00215	0.00058	39.97	0.01920	0.00074	0.00003	95.10	0.00307
SUN 8024	0.00189	0.00054	89.19	0.03067	0.00096	0.00081	59.97	0.04842
SUN 8033	0.00063	0.00027	75.43	0.01624		0.00004	171.73	0.00642
SUN 8034		0.00018	137.95	0.01246	0.00045			
SUN 8035	0.00057	0.00037	39.61	0.01089		0.00003	92.37	0.00305
SUN 8043	0.00040	0.00030	148.42	0.02731	0.00120	0.00130	57.99	0.07543
SUN 8044	0.00102	0.00026	84.32	0.01284	0.00114	0.00056	19.54	0.01086
SUN 8045	0.00023	0.00015	110.80	0.01465	0.00229	0.00081	89.87	0.07264
SWT 8001	0.00183	0.00095	46.04	0.03740				
SWT 8002	0.00193	0.00219	34.63	0.07177				
TEA 4002	0.00109	0.00074	36.60	0.03528				
TEA 4004		0.00011	38.92	0.00422				
TEA 4007		0.00024	15.00	0.00367				
THO 8012	0.00157	0.00026	134.53	0.01768	0.00055	0.00004	139.07	0.00509
THO 8013	0.00103	0.00017	158.51	0.02317		0.00002	73.00	0.00137
THO 8014		0.00000	142.43	0.00031				
THO 8022	0.00022	0.00010	51.16	0.00496	0.00010			
THO 8024	0.00012	0.00002	175.42	0.00270				
THY 4003	0.00039	0.00064	101.17	0.08718		0.00051	31.06	0.01580
THY 4004	0.00045	0.00045	143.49	0.09226	0.00089	0.00007	115.00	0.00774

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
THY 4005		0.00055	36.51	0.01943				
THY 4006		0.00037	87.00	0.03237				
THY 4007		0.00071	82.87	0.05104		0.00001	172.00	0.00199
THY 4008	0.00037	0.00030	71.99	0.02124	0.00025			
THY 4009	0.00054	0.00029	177.49	0.04075	0.00053			
THY 4010	0.00029	0.00038	69.42	0.03030		0.00021	159.49	0.03313
THY 4011	0.00020	0.00040	25.00	0.01151				
THY 4012		0.00046	125.00	0.05790				
THY 4013		0.00070	100.68	0.07037		0.00048	41.02	0.01971
THY 4014	0.00033	0.00025	85.24	0.02894				
TNY 4001	0.00051	0.00046	205.55	0.08804		0.00023	85.47	0.01987
TNY 4002		0.00113	141.68	0.11170		0.00102	70.68	0.07177
TNY 4003		0.00058	126.49	0.05371				
TNY 4008		0.00037	154.08	0.03331		0.00061	74.10	0.04527
TNY 4010	0.00146	0.00086	165.05	0.09743		0.00009	251.76	0.02365
TON 4003		0.00060	47.13	0.02846				
TON 4006	0.00056	0.00039	305.00	0.01609				
TON 4007	0.00043	0.00029	113.88	0.02519	0.00043			
TOT 4001	0.00012	0.00004	167.00	0.00605				
TOT 4002		0.00026	31.00	0.00772				
TOT 4007	0.00006	0.00004	92.32	0.00490				
TUR 8001	0.00016	0.00013	70.57	0.00731	0.00032	0.00003	62.69	0.00212
TUR 8003	0.00013	0.00006	265.74	0.01014		0.00002	166.37	0.00324
TUR 8004	0.00173	0.00062	77.79	0.03887				
TUR 8015	0.00217	0.00043	86.32	0.03157	0.00201	0.00075	17.16	0.01283
TUR 8025	0.00220	0.00132	62.24	0.05542	0.00111	0.00041	94.26	0.03849
UN 4004								
UN 4006								
UN 4010								
UN 4011								
UNC 4001		0.00054	31.50	0.02586				
UNC 4006		0.00148	49.54	0.07565				
UNC 4007		0.00029	31.50	0.00912				
UNC 4009		0.00085	39.26	0.02840				
UNC 4010		0.00049	46.69	0.01912	0.00032	0.00032	10.00	0.00319
UNC 4012		0.00058	31.50	0.01840	0.00027			
VIL 8001	0.00144	0.00017	104.25	0.01185	0.00122	0.00060	152.23	0.09143
VNH 4002		0.00006	166.00	0.00969				
VNH 4003	0.00045	0.00000	180.00	0.00008		0.00043	23.53	0.01012
VNK 4006								
VNK 4010	0.00086	0.00043	27.98	0.01197				
VNK 4012		0.00007	30.00	0.00639				
VNK 4013	0.00036	0.00036	53.50	0.01982		0.00035	16.11	0.00557
VNK 4015								
WAD 8011	0.00036	0.00031	126.21	0.03185	0.00049	0.00024	80.12	0.01955
WAD 8013	0.00078	0.00050	68.28	0.02292	0.00121	0.00169	59.51	0.10036

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	MAIFI	SAIFI	CAIDI	SAIDI	MAIFI	SAIFI	CAIDI	SAIDI
WAD 8022	0.00148	0.00048	104.40	0.02581	0.00059	0.00062	24.98	0.01548
WAD 8025	0.00180	0.00078	84.43	0.04230		0.00014	128.01	0.01809
WAD 8041	0.00050	0.00072	69.26	0.02930	0.00034	0.00088	72.88	0.06448
WAN 8014	0.00083	0.00023	69.94	0.01007	0.00064	0.00004	124.42	0.00500
WAN 8015		0.00008	71.82	0.00558	0.00024	0.00000	121.00	0.00005
WAN 8022	0.00192	0.00027	90.57	0.01467	0.00077	0.00023	18.04	0.00412
WAN 8025	0.00132	0.00002	50.00	0.00275	0.00101	0.00005	90.00	0.00487
WAR 4001	0.00056	0.00067	82.16	0.04252		0.00060	95.25	0.05687
WAR 4002		0.00022	87.22	0.01686				
WAR 4003		0.00016	70.47	0.01096				
WAR 4004	0.00019	0.00020	162.75	0.01790		0.00018	183.59	0.03346
WAR 4005		0.00017	62.36	0.00972				
WAR 4006	0.00029	0.00030	42.38	0.01257		0.00002	166.00	0.00277
WAR 4007		0.00030	67.57	0.02050				
WAR 4008		0.00017	112.05	0.01953				
WAR 4009	0.00028	0.00037	51.79	0.01630				
WAV 4001		0.00024	31.00	0.00737		0.00013	68.00	0.00917
WAV 4004		0.00026	116.33	0.02406	0.00025			
WAV 4015	0.00072	0.00079	94.90	0.07106				
WAV 4016	0.00016	0.00004	61.00	0.00125	0.00004	0.00008	15.53	0.00117
WAV 4018		0.00075	112.68	0.07451		0.00053	51.00	0.02681
WEW 8011	0.00113	0.00068	80.42	0.05172	0.00137	0.00045	90.78	0.04101
WEW 8014	0.00015	0.00008	105.50	0.00714	0.00024			
WEW 8015	0.00015	0.00006	42.73	0.00252				
WEW 8021	0.00243	0.00140	76.89	0.11332	0.00144	0.00029	39.49	0.01152
WEW 8023	0.00033	0.00036	41.22	0.01499	0.00046	0.00028	20.41	0.00567
WEW 8025	0.00036	0.00016	68.31	0.00630	0.00034	0.00033	35.71	0.01184
WEW 8031	0.00013	0.00003	505.67	0.00932	0.00015			
WEW 8032	0.00001	0.00001	30.58	0.00025				
WEW 8033	0.00256	0.00084	106.17	0.04947	0.00397	0.00230	91.18	0.20936
WEW 8034	0.00015	0.00014	121.88	0.01301				
WEW 8041	0.00025	0.00012	58.80	0.00446		0.00001	99.14	0.00110
WEW 8042	0.00093	0.00096	57.30	0.05564	0.00173	0.00029	116.58	0.03336
WEW 8044	0.00118	0.00086	37.91	0.03418	0.00063	0.00126	12.31	0.01547
WFL 8011	0.00118	0.00049	117.68	0.04186		0.00011	87.53	0.00951
WFL 8012	0.00138	0.00059	41.97	0.02723	0.00047	0.00013	133.74	0.01693
WFL 8021	0.00079	0.00017	32.00	0.00531	0.00027	0.00021	89.53	0.01906
WFL 8032	0.00215	0.00155	54.39	0.07771	0.00055	0.00041	90.07	0.03710
WFL 8034	0.00141	0.00061	161.91	0.09736		0.00004	105.07	0.00439
WFL 8041	0.00119	0.00079	105.88	0.08710	0.00135			
WMT 4002	0.00045	0.00016	98.05	0.01250				
WMT 4004	0.00045	0.00009	153.91	0.00429	0.00006	0.00010	269.43	0.02799
WMT 4005	0.00056	0.00019	175.50	0.04236	0.00077	0.00022	93.73	0.02082
WMT 4006	0.00072	0.00025	94.41	0.02600		0.00053	33.53	0.01767
WMT 4007	0.00072	0.00039	152.14	0.10679	0.00079	0.00011	119.23	0.01295
WOA 4003		0.00054	122.98	0.01890		0.00000	916.89	0.00328

	5 Year Benchmark				Report Quarter Performance (Q1-2023)			
Circuit	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**	**MAIFI**	**SAIFI**	**CAIDI**	**SAIDI**
WOD 4001	0.00020	0.00009	72.00	0.00915				
WOD 4004	0.00020	0.00008	102.90	0.00837				
WOD 4006	0.00025	0.00024	44.72	0.01106		0.00000	347.00	0.00138
WOD 4007	0.00017							
WOD 4008	0.00016	0.00010	50.52	0.00304		0.00017	15.00	0.00250
WOD 4009	0.00009	0.00009	36.56	0.00343				
WOD 4010	0.00026	0.00013	56.55	0.01473				
WOR 8011	0.00180	0.00039	121.88	0.04242	0.00051	0.00006	6.00	0.00036
WOR 8013	0.00247	0.00053	81.09	0.04137	0.00005	0.00002	60.00	0.00148
WOR 8017	0.00182	0.00163	65.21	0.09589		0.00002	63.35	0.00116
WOR 8018	0.00042	0.00019	120.65	0.02589	0.00253	0.00171	33.56	0.05726
WOR 8019	0.00123	0.00044	71.42	0.01697	0.00060	0.00018	6.00	0.00108
WOR 8021	0.00066	0.00023	213.28	0.02546		0.00004	205.86	0.00770
WOR 8022	0.00172	0.00039	99.97	0.03769		0.00027	39.79	0.01083
WOR 8024	0.00021	0.00004	320.00	0.01985	0.00043	0.00000	119.00	0.00009
WOR 8025	0.00220	0.00131	117.25	0.21998	0.00018	0.00034	46.94	0.01607
WOR 8034	0.00013	0.00004	84.33	0.00344	0.00037	0.00006	91.06	0.00591
WOR 8035	0.00103	0.00014	74.28	0.00648	0.00036	0.00005	63.62	0.00337
WOR 8037	0.00023	0.00005	205.68	0.01092	0.00022	0.00013	83.55	0.01124
WOR 8039	0.00284	0.00050	78.02	0.02839		0.00007	84.58	0.00613
WRY 4001		0.00018	124.36	0.02382		0.00003	253.00	0.00705
WRY 4005		0.00019	208.72	0.04428				
WRY 4006		0.00014	169.00	0.02343				
WRY 4010		0.00029	90.96	0.03278				
WRY 4011		0.00020	265.33	0.03944		0.00063	49.11	0.03096
WYN 4001	0.00033	0.00017	235.50	0.00272	0.00021	0.00010	118.00	0.01146
WYN 4002	0.00089	0.00086	54.65	0.05393	0.00044			
WYN 4003	0.00086	0.00029	94.90	0.02237		0.00003	176.00	0.00448
WYN 4004	0.00056	0.00084	11.01	0.00973				
WYN 4005	0.00043	0.00034	100.00	0.02802	0.00076			
WYN 4006	0.00056					0.00001	62.00	0.00044
WYN 4007		0.00013	297.67	0.01586	0.00018			
WYN 4008	0.00017	0.00042	22.80	0.01149				
WYN 4009	0.00028	0.00030	68.92	0.02062		0.00002	174.00	0.00284
WYN 4010		0.00041	238.50	0.04976		0.00037	111.31	0.04111
YRD 8011	0.00017	0.00006	65.98	0.00208	0.00022	0.00004	133.00	0.00551
YRD 8012	0.00057	0.00030	98.22	0.03054	0.00003	0.00017	89.53	0.01479
YRD 8014	0.00076	0.00011	6.00	0.00068	0.00031	0.00006	41.59	0.00262
YRD 8021	0.00025	0.00027	62.77	0.01610	0.00103	0.00014	27.75	0.00382
YRD 8023	0.00072	0.00020	141.65	0.00763		0.00020	13.66	0.00268
YRD 8024	0.00045	0.00057	44.61	0.02372	0.00033	0.00048	69.20	0.03333

Danielle Lopez
Associate Counsel-Regulatory

Law Department
80 Park Plaza, T10, Newark, New Jersey 07102-4194
Email: danielle.lopez@pseg.com

PSEG Services Corporation

March 16, 2023

VIA ELECTRONIC MAIL ONLY
Carmen Diaz, Acting Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Flr.
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: NEXT PHASE OF THE PSE&G GAS SYSTEM MODERNIZATION PROGRAM MONTHLY REPORT – FEBRUARY 2023

Dear Acting Secretary Diaz:

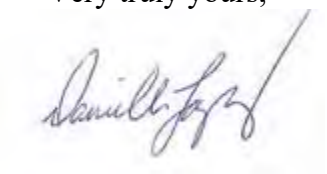
Enclosed for filing is the letter and enclosures providing Public Service Electric & Gas Company's (PSE&G's) monthly report for February 2023 on its Next Phase of the Gas System Modernization Program (GSMP II or the Program).

The GSMP II was approved by a Board Order dated May 22, 2018 in BPU Docket No. GR17070776. That Order adopted a Stipulation pursuant to which PSE&G is operating the Program. This report is filed pursuant to paragraph 43 of that Stipulation and is designed to address the first four items contained in Attachment C to that Stipulation.

The first three items are addressed in the attached materials. With regard to item 4, there were no funds or credits received from the United States government, the State of New Jersey, a county or a municipality, for work related to any of the Program projects.

Consistent with the Order issued by the Board in connection with In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations, BPU Docket No. EO20030254, Order dated March 19, 2020, this document is being filed electronically with the Secretary of the Board and the Division of Rate Counsel. No paper copies will follow.

Very truly yours,



Danielle Lopez

cc - E-Mail Only:
Robert Brabston
Malike Cummings

Mike Kammer
Ilene Lampitt
Brian Lipman
Karen Forbes
Matko Illic
Maura Caroselli
Loni Diaz
Carol Artale
Pamela Owen

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

1) PSE&G's overall approved GSMP II Rate Mechanism and Stipulated Base capital budget broken down by major categories, both budgeted and actual amounts.

GSMP II Major Project Categories	Overall Approved Program	Feb PTD Budget	Feb PTD Actual
Replacement Main $	$ 1,087,400,000	$ 1,087,400,000	$ 1,174,382,233
Replacement Service $	$ 482,000,000	$ 482,000,000	$ 403,567,244
Regulator Elimination $	$ 5,600,000	$ 5,600,000	$ 5,287,825
Total	$ 1,575,000,000	$ 1,575,000,000	$ 1,583,237,302

Stipulated Base II Major Project Categories	Overall Approved Program	Feb PTD Budget	Feb PTD Actual
Replacement Main $	$ 217,200,000	$ 217,200,000	$ 191,408,375
Replacement Service $	$ 34,800,000	$ 34,800,000	$ 45,947,312
Large Diameter HP Joints	$ 18,000,000		$ -
GSMP Meter Reconstruction $	$ 30,000,000	$ 48,000,000	$ 68,146,528
Total	$ 300,000,000	$ 300,000,000	$ 305,502,215

2) b. Expenditures incurred to date and amounts transferred to plant in-service, by project. Expenditures broken down by internal labor, materials, and other costs. Internal labor hours broken down by regular hours and overtime hours.

Expenditures Incurred To Date GSMP II Projects	Feb PTD Actual Internal Labor $	Feb PTD Actual Material $	Feb PTD Actual Other $	Feb PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ 209,490,466	$ 74,780,643	$ 890,111,124	$ 1,174,382,233	$ 1,122,729,271
Replacement Service	$ 76,542,273	$ 32,920,978	$ 294,103,993	$ 403,567,244	$ 403,397,947
Regulator Elimination	$ 1,180,725	$ 193,248	$ 5,094,577	$ 5,287,825	$ 2,242,714
Total	$ 287,213,464	$ 107,894,868	$ 1,189,309,694	$ 1,583,237,302	$ 1,528,369,931

GSMP II Internal Labor Hours	
Internal Labor - Regular Hours	2,935,078
Internal Labor - Overtime Hours	965,204

Expenditures Incurred To Date Stipulated Base II Projects	Feb PTD Actual Internal Labor $	Feb PTD Actual Material $	Feb PTD Actual Other $	Feb PTD Actual Total $	Amount to Plant In-Service
Replacement Main	$ 27,215,050	$ 18,948,831	$ 145,244,493	$ 191,408,375	$ 182,477,887
Replacement Service	$ 8,498,426	$ 872,286	$ 36,576,600	$ 45,947,312	$ 45,921,442
Large Diameter HP Joints	$ -	$ -	$ -	$ -	$ -
GSMP Meter Reconstruction	$ 22,302,357	$ 5,832,690	$ 40,011,481	$ 68,146,528	$ 68,146,528
Total	$ 58,015,834	$ 25,653,808	$ 221,832,574	$ 305,502,215	$ 296,545,856

Stip Base II Internal Labor Hours	
Internal Labor - Regular Hours	581,910
Internal Labor - Overtime Hours	216,054

PSE&G - GAS SYSTEM MODERNIZATION PROGRAM
ATTACHMENT C - MONTHLY REPORT

REPORT DATE: February 2023
2a - Description of projects
2c - Projected and actual miles of main installed
2d - Projected and actual number of services installed

	Project	Sub-Project	Project Completion Date	Units	Size Installed	Material Installed	2019 Quantity Completed	2020 Quantity Completed	2021 Quantity Completed	2022 Quantity Completed	Projected Quantity Jan 2023	Actual Quantity Jan 2023	Projected Quantity Feb 2023	Actual Quantity Feb 2023	2023 Estimated Quantity	Quantity Completed 2023 Year To Date	Total Program Quantity Completed To Date
GAS SYSTEM MODERNIZATION PROGRAM	Replace Facilities Blanket	Replacement Main	Dec-23	Feet of Main	2"	Plastic	**746,745**	**1,166,556**	**1,060,930**	**386,873**	2,416	42,005	957	54,332	**3,372**	**96,337**	**3,457,441**
					4"	Plastic	**246,779**	**335,330**	**277,288**	**148,203**	756	5,817	322	13,273	**1,077**	**19,090**	**1,026,690**
					6"	Plastic	**80,521**	**115,300**	**105,458**	**31,856**	395	6,192	165	257	**560**	**6,449**	**339,584**
					8"	Plastic	**34,576**	**40,792**	**28,722**	**13,494**	0	1,560	20	24	**21**	**1,584**	**119,168**
					12"	Plastic	**-**	**-**	**-**	**-**					**-**	**-**	**-**
					12"	Steel	**-**	**17,397**	**5,021**	**846**					**-**	**-**	**23,264**
					16"& 20"	Steel	**-**	**5,889**	**7,531**	**8,099**					**-**	**-**	**21,519**
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**1,108,621**	**1,681,264**	**1,484,950**	**589,371**	**3,566**	**55,574**	**1,464**	**67,886**	**5,030**	**123,460**	**4,987,666**
	Replace Facilities Blanket	Replacement Service	Dec-23	Services Replaced	≤ 2"	Plastic	**14,653**	**18,218**	**27,320**	**20,456**	1,151	626	994	705	**2,145**	**1,331**	**81,978**
					>2"	Plastic	**2**	**4**	**4**	**6**					**-**	**-**	**16**
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**14,655**	**18,222**	**27,324**	**20,462**	**1,151**	**626**	**994**	**705**	**2,145**	**1,331**	**81,994**
	Abandon Facilities Blanket	Abandon Regulator	Dec-23	Regulators Abandoned	N/A	N/A	**22**	**32**	**59**	**35**		3		9		**12**	**160**
	Abandon Facilities Blanket	**Abandon Regulator**	**N/A**	**Regulators Abandoned**	**N/A**	**N/A**	**22**	**32**	**59**	**35**		**3**		**9**		12	**160**
STIPULATED BASE	Replace Facilities Blanket	Replacement Main	Dec-23	Feet of Main	2"	Plastic	**79,126**	**78,746**	**94,927**	**202,853**	1,146	21,372	370	27,032	**1,515**	**48,404**	**504,056**
					4"	Plastic	**30,415**	**19,023**	**20,923**	**88,704**	462	4,004	341	3,575	**803**	**7,579**	**166,644**
					6"	Plastic	**9,773**	**3,061**	**11,889**	**12,326**	463	35	278	2,172	**741**	**2,207**	**39,256**
					8"	Plastic	**277**	**284**	**775**	**15,097**	201	904	17	2,054	**218**	**2,958**	**19,391**
					8"	Steel	**-**	**-**	**-**	**-**	-	-	-	-	**-**	**-**	**-**
					12"	Plastic	**2**	**-**	**-**	**9**	-	110	-	79	**-**	**189**	**200**
					12"	Steel	**171**	**12,487**	**4,984**	**11,537**	1,525	-	354		**1,879**	**-**	**29,179**
					16"	Steel	**100**	**-**	**-**	**2,595**	561	-	790	1,324	**1,352**	**1,324**	**4,019**
					20"	Steel	**-**	**-**	**20**	**35**	-	-	-		**-**	**-**	**55**
					24"	Steel	**-**	**-**	**-**	**572**	-	-	-		**-**	**-**	**572**
					42"	Steel	**700**	**597**	**1,900**	**-**	-	-	-		**-**	**-**	**3,197**
	Replace Facilities Blanket	**Replacement Main**	**N/A**	**Feet of Main**	**N/A**	**N/A**	**120,564**	**114,198**	**135,418**	**333,728**	**4,357**	**26,425**	**2,151**	**36,236**	**6,508**	**62,661**	**766,569**
	Replace Facilities Blanket	Replacement Service	Dec-23	Services Replaced	≤ 2"	Plastic	**1,393**	**1,107**	**932**	**4,678**	124	519	138	573	**262**	**1,092**	**9,202**
					>2"	Plastic	**-**	**-**	**-**	**-**					**-**	**-**	**-**
	Replace Facilities Blanket	**Replacement Service**	**N/A**	**Services Replaced**	**N/A**	**N/A**	**1,393**	**1,107**	**932**	**4,678**	**124**	**519**	**138**	**573**	**262**	**1,092**	**9,202**
	Large Diameter High Pressure Joints	Joints	Dec-23	HP Joints Encapsulated	N/A	N/A	**-**	**-**	**-**	**-**					**-**	**-**	**-**
	Large Diameter High Pressure Joints	**Joints**	**N/A**	**HP Joints Encapsulated**	**N/A**	**N/A**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Project Timeline			2019												2020												2021												2022												2023												2024											
Activity Name	**Start**	**Finish**	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
GSMP II											

PSE&G
Infrastructure Advancement Program

Independent Monitor

July-December 2022

Final Report

Prepared and Submitted by: Pegasus-Global Holdings, Inc.

DECEMBER 20, 2023

PEGASUS GLOBAL HOLDINGS, INC.®

Table of Contents

I. Executive Summary 1
II. Program Status 3
A. Key Decisions 6
B. Cost Assignments 7
1. Costs of Removal (COR) 8
2. Construction Work-in-Progress (CWIP) 8
3. Allowance for Funds Used During Construction (AFUDC) 8
4. Allocated Overheads 9
5. IAP Rate Mechanism vs. Stipulated Base 10
C. System Performance 11
1. Major Event Performance 12
2. Non-Major Event Performance 12
III. Subprogram & Project Status 13
A. Electric Outside Plant 13
1. Spacer Cable Conversion (Open Wire to Spacer) 15
2. Lashed Cable Replacement 16
3. Spacer Hardware Upgrades 19
4. Conventional Underground (CUG) Cable Replacement 21
5. Voltage Optimization (Capacitor Bank Upgrades) 23
B. Substation Modernization 24
1. 26kV Station Upgrade 24
2. 4kV Station Modernization 26
C. Gas M&R Station Modernization 29
D. Electric Stipulated Base 32
1. Buried Underground Distribution (BUD) Cable Replacement 32
2. Open Wire Secondary Upgrades 34

Appendices

Appendix A ..... Draft Report Comments and Responses

List of Acronyms and Abbreviations

Allowance for Funds Used During Construction	AFUDC
Buried Underground Distribution	BUD
Construction Work-in-Progress	CWIP
Conventional Underground	CUG
Cost per Unit	CPU
Costs of Removal	COR
Customer Average Interruption Duration Index	CAIDI
Estimate at Completion	EAC
Federal Energy Regulatory Commission	FERC
Financial Accounting Standards Board	FASB
Gas Metering and Regulating	Gas M&R
Generally Accepted Accounting Principles	GAAP
Independent Monitor	IM
Infrastructure Advancement Program	IAP/Program
Inside Plant	IP
Issued for Bid	IFB
Issued for Construction	IFC
Mono Ethylene Glycol	MEG
New Jersey Board of Public Utilities	BPU
Oil Circuit Breakers	OCB
Program Execution Plan	PEP
Program Management Organization	PMO
Projects & Construction	P&C
Public Service Electric & Gas	PSE&G
Purchase Order	PO
Remote Terminal Unit	RTU
Risk and Contingency	R&C
System Average Interruption Frequency Index	SAIFI
Supervisory Control and Data Acquisition	SCADA
Utility Review Board	URB
Work Breakdown Structure	WBS

I. Executive Summary

Public Service Electric & Gas's (PSE&G's) Infrastructure Advancement Program (IAP, or "Program") was established from a Stipulation that the involved parties agreed to in June 2022, as approved by a New Jersey Board of Public Utilities (BPU) Order dated June 29, 2022, with an effective date of July 1, 2022. The Stipulation provided the approved investments to be made by PSE&G on its electric and gas distribution systems, including those subject to an accelerated rate recovery mechanism (IAP Rate Mechanism) and those that are not recoverable through Infrastructure Investment Program (IIP) regulations or the IAP Rate Mechanism, but instead executed as Stipulated Base projects. In total, the Stipulation approved $351.0 million in investments to be made under the IAP Rate Mechanism and $160.0 million in investments within Stipulated Base with the work to be performed from July 1, 2022 until June 30, 2026.

As part of the Stipulation, PSE&G was required to retain an independent monitor (IM) *"to review and report to Board Staff and Rate Counsel on the impact of the IAP on overall system performance during severe weather events; cost effectiveness and efficiency; appropriate cost assignment; and other information deemed appropriate by the Company, Board Staff and Rate Counsel."* Pegasus-Global Holdings, Inc. (Pegasus-Global) was engaged to serve as the IM for the IAP and held an introductory meeting with PSE&G on January 17, 2023 ahead of a formal kickoff meeting on April 19, 2023. In the period between the introductory meeting and the formal kickoff meeting, the initial IAP documentation was requested by the IM and provided by PSE&G. Similar to the Energy Strong 2 Program, PSE&G and the IM have also commenced meeting on a bi-weekly basis to review the status of the IAP. This initial IM report discusses the status of the Program from its commencement on July 1, 2022 through December 31, 2022.

A summary of the approved IAP investments is provided in **Table 1 – IAP Overall Cost Summary as of December 31, 2022**, which shows the original Stipulation budget, actual costs to date, and PSE&G's current forecast.

Table 1 – IAP Overall Cost Summary as of December 31, 2022

Subprogram	Q3 2022 Spend	Q4 2022 Spend	Total Actual Costs to Date	Total Forecast	Stipulation Budget	% of Actuals to Budget	Forecasted Final In-Service
IAP Rate Mechanism							
Electric Outside Plant							
Spacer Cable Conversion	$0	$0	$0	$42,000,000	$42,000,000	0%	Jun 2026
Lashed Cable Replacement	$1,394	$1,290,876	$1,292,270	$14,000,000	$14,000,000	9%	Jun 2026
Spacer Hardware Upgrade	$555	$5,222,157	$5,222,712	$15,000,000	$15,000,000	35%	Jun 2024
Conventional Underground (CUG) Cable Replacement*	$4,454	$1,357,373	$1,361,827	$8,000,000	$8,000,000	17%	Jun 2026
Voltage Optimization*	$555	$95,385	$95,939	$12,000,000	$12,000,000	1%	Jun 2026
Subtotal	*$6,958*	*$7,965,791*	*$7,972,748*	*$91,000,000*	*$91,000,000*	*9%*	*Jun 2026*
Substation Modernization							

Subprogram	Q3 2022 Spend	Q4 2022 Spend	Total Actual Costs to Date	Total Forecast	Stipulation Budget	% of Actuals to Budget	Forecasted Final In-Service
26kV Station Upgrade	$0	$607,285	$607,285	$33,000,000	$33,000,000	2%	May 2026
4kV Station Modernization*	$0	$585,535	$585,535	$101,074,091	$157,200,000	0%	Sep 2025
Subtotal	*$0*	*$1,192,820*	*$1,192,820*	*$134,074,091*	*$190,200,000*	*1%*	*May 2026*
Gas M&R Station Modernization							
Gas M&R Station Modernization	$0	$896,456	$896,456	$64,556,595	$69,800,000	1%	Oct 2025
Subtotal	*$0*	*$896,456*	*$896,456*	*$64,556,595*	*$69,800,000*	*1%*	*Oct 2025*
IAP Rate Mechanism Total	***$6,958***	***$10,055,067***	***$10,062,025***	***$289,630,686***	***$351,000,000***	**3%**	***Jun 2026***
Stipulated Base							
Electric Stipulated Base	$193,432	$10,128,252	$10,321,684	$127,597,640	$142,600,000	7%	Jun 2026
Gas Stipulated Base	$0	$0	$0	$17,400,000	$17,400,000	0%	Oct 2025
Stipulated Base Total	***$193,432***	***$10,128,252***	***$10,321,684***	***$144,997,640***	***$160,000,000***	**6%**	***Jun 2026***
Total	**$200,390**	**$20,183,319**	**$20,383,708**	**$434,628,326**	**$511,000,000**	**4%**	**Jun 2026**

-These project have funding through both the IAP Rate Mechanism and the Electric Stipulated Base, the Stipulation Budget for these projects refers to the IAP Rate Mechanism funding. Additional details of the split between IAP Rate Mechanism and Stipulated Base spend is provided in* ***Section II.B.5.*

As shown in **Table 1**, in the first two quarters of the IAP, PSE&G incurred approximately $20.4 million in total actual costs representing 4% of the overall budget and split nearly evenly between the IAP Rate Mechanism and the Stipulated Base components of the Program. Of this $20.4 million in actual spend, the majority came within the Open Wire Secondary Upgrades under the Stipulated Base and the Spacer Upgrade projects under the IAP Rate Mechanism. These two projects are planned to be the first completed under the Program, with the Open Wire Secondary Upgrades forecasted for completion by the end of 2023 and the Spacer Upgrade projects forecasted for completion by June 2024. For the other projects, the primary activities during this initial period centered around planning and preliminary engineering.

The forecasts shown in **Table 1** for the individual projects that comprise the IAP are reflective of the status of the planning and preparation for these projects as of the end of 2022. For instance, as of the end of 2022 the projects within the Electric Outside Plant subprogram had a total forecast equivalent to the Stipulation budget as the detailed forecasts from each of the Divisions was still being developed at this time. For the Electric Stipulated Base forecast, the forecast of approximately $127.6 million is approximately $15.0 million under the Stipulation budget for the Electric Stipulated Base spend, this is due to PSE&G allocating $15.0 million of the Electric Stipulated Base funding to the 4kV Station Modernization subprogram, which is currently forecasted to be completed under budget (see **Table 6** for additional detail on the split between the IAP Rate Mechanism and the Stipulated Base).

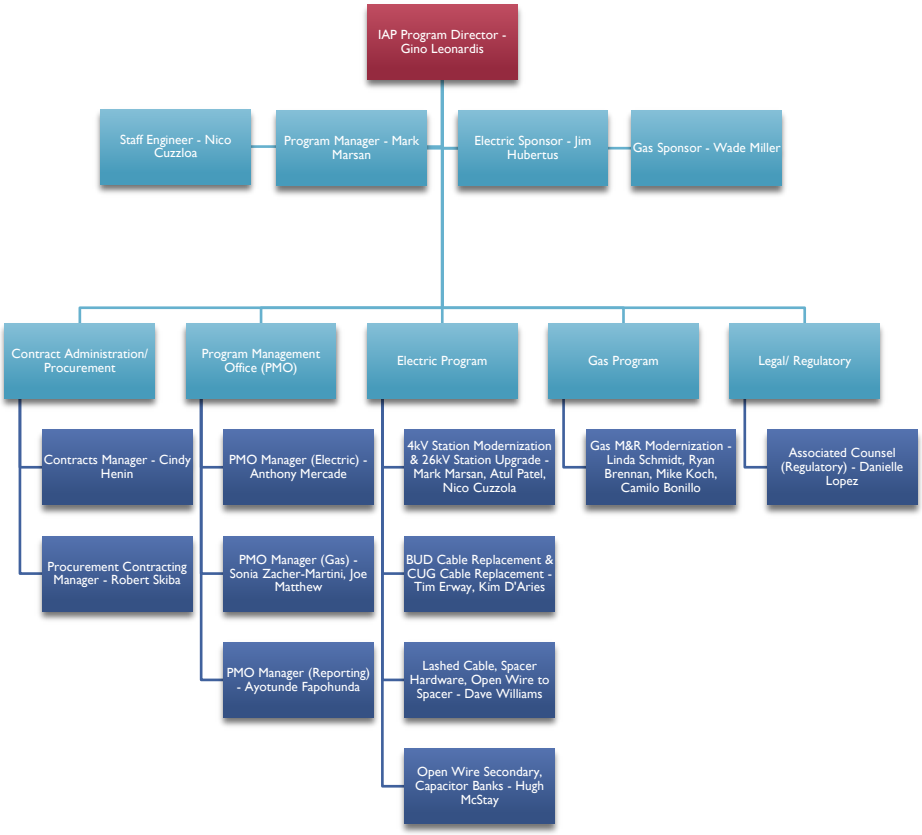
Conclusions

- In this initial reporting period of July-December 2022, the bulk of the work on the IAP involved initial planning and alignment, along with the start of engineering and field inspections. In August and September 2022, PSE&G received Program internal funding approval from its Utility Review Board (URB) for the subprograms and major projects that comprise the IAP. In the fourth quarter of 2022, construction began on the first set of projects in the Program.
- For the larger, more traditional projects, including the 4kV Station Modernization projects and the Gas M&R Station Modernization projects, efforts have focused on planning, identifying and beginning procurement of long lead items, and preliminary engineering reviews ahead of the detailed engineering commencing in 2023 and construction commencing in 2024 (and 2025 for the final two Gas M&R projects).
- The physical construction/installation work on the projects within the IAP will be performed by a mix of internal PSE&G crews, Division resources, and contractors. For the Substation Modernization and Gas M&R Station Modernization projects, the bulk of the work will be performed by construction contractors (some of the outside plant work will be performed by the Divisions), while for the Electric Outside Plant and Electric Stipulated Base projects, the work will be performed utilizing a mix of Division resources and contractors, balancing the skill sets and availability of the Divisions to the specific scopes of work. In general, PSE&G seeks to utilize internal resources when feasible, appropriate, and when such resources are available, supplementing with contractor resources as necessary.
- For many of the Electric Outside Plant projects within the IAP PSE&G has identified an assumed scope of work (e.g. number of circuits to be improved) based on a preliminary estimated cost per unit and the approved Stipulation budget. However, because of the variety in field conditions and installation effort required for the distinct projects, the cost per unit is expected to change based on these actual conditions. PSE&G intends to use the first few circuits for each subcomponent to establish a baseline estimate and will update its scope targets on a quarterly basis once it has sufficient actual costs data to inform this effort.
- The prioritization criteria for the Electric Outside Plant projects is generally driven by the recent observed performance of the circuits, including specifically outages that were related to the scope of work (e.g. Lashed Cable Replacement prioritization criteria includes filtering for lashed cable related outages), along with cost-benefit assessments to ensure the selected projects represent an efficient use of the Program funds in achieving the Program objectives. Details of the specific prioritization criteria for these projects is discussed in each of the project sections.
- While there has only been limited work performed on the Program through the end of 2022 and limited actual data to evaluate and compare performance, the actual performance of the few completed circuits reflected better performance than the 5-year SAIDI average.

II. Program Status

To carry out the IAP, PSE&G established a program management organization that established leads for the projects within the Program and the primary functional support involved in delivering the Program (contract administration, Program Management Office (PMO), and legal/regulatory). **Figure 1 – IAP Organization** shows this program management organization established by PSE&G.

Figure 1 – IAP Organization



In supporting the delivery of the Program, the PMO manages all schedule and financial related tasks on the Program, including monitoring and controlling of costs and schedule. These efforts include creation of work breakdown structures (WBS) for the entire scope of work, managing work orders, monitoring cost forecasts, reporting in-service costs, managing schedule updates, and related efforts.

Following the BPU approval of the Stipulation via its June 29, 2022 Order (with an effective date of July 1, 2022), PSE&G sought internal funding approval for each of the subprograms that comprise the IAP from its Utility Review Board (URB).

In August 2022, PSE&G requested authorization of $423.8 million in funding, aligning with the Stipulation established budget for the electric portions of the Program, including both the IAP Rate Mechanism ($281.2 million) and Stipulated Base ($142.6 million) amounts. This request also sought the release of $218.6 million in funds towards the Electric Outside Plant subprogram, which is split between IAP Rate Mechanism funds ($91 million) and Stipulated Base funds ($127.6 million). The URB approved funding levels for the projects under the Electric Outside Plant subprogram are presented in **Table 2 – Electric Outside Plant URB Approvals**.

Table 2 – Electric Outside Plant URB Approvals

Project	URB Approved Funding		
	IAP Rate Mechanism	Stipulated Base	Total
Space Cable Conversion	$42,000,000	$0	$42,000,000

Project	URB Approved Funding		
	IAP Rate Mechanism	Stipulated Base	Total
Lashed Cable Replacement	$14,000,000	$0	$14,000,000
Spacer Hardware Upgrades	$15,000,000	$0	$15,000,000
CUG Cable Replacement	$8,000,000	$15,000,000	$23,000,000
Voltage Optimization	$12,000,000	$24,600,000	$36,600,000
Buried Underground Distribution (BUD) Cable Replacement	$0	$70,000,000	$70,000,000
Open Wire Secondary Upgrades	$0	$18,000,000	$18,000,000
Total	**$91,000,000**	**$127,600,000**	**$218,600,000**

These approved funding amounts reflect the Office level estimate developed by PSE&G for the individual projects. Due to the nature of these projects (smaller, repetitive type work) with defined budgets, but without a specifically defined scope (e.g. number of units, feet of cable, etc.), PSE&G is not using risk and contingency (R&C) in these budgets and intends to use the actual costs from the initial installations to inform the forecast for the remaining work on the subprogram. While the specific Electric Outside Plant scopes reflect smaller, repetitive projects that are inherently flexible as to exact quantities to be installed (which is ultimately based on the observed cost per unit that can vary depending on the specific characteristics of each individual project), PSE&G's initial scope assumptions for each of the projects within this subprogram are as follows:

1. Spacer Cable Conversion: to replace approximately 57 miles of aging 3-phase open wire with new spacer cable type construction.
2. Lashed Cable Replacement: to replace approximately 14 miles of lashed cable with spacer cable construction.
3. Spacer Hardware Upgrades: to replace approximately 300 miles of existing construction with new hardware.
4. CUG Cable Replacement: to replace approximately 34 miles of cable.
5. Voltage Optimization: to replace approximately 1,050 aging 13kV pole top capacitors and switches.
6. BUD Cable Replacement: to replace approximately 1,400 sections with new cable and single-phase transformers.
7. Open Wire Secondary Upgrades: to replace approximately 600 secondary locations of open wire secondary.

In September 2022, PSE&G sought the release of the balance of the Program funding for the electric scope, specifically $133.4 million towards the Substation Modernization subprogram. As with the Electric Outside Plant subprogram, this approved funding includes both IAP Accelerated Recovery and Stipulated Base funds, with the breakdown shown in **Table 3 – Substation Modernization URB Approvals**.

Table 3 – Substation Modernization URB Approvals

Project	URB Approved Funding		
	IAP Rate Mechanism	Stipulated Base	Total
4kV Station Modernization	$157,200,000	$15,000,000	$172,200,000
26kV Station Upgrade	$33,000,000	$0	$33,00,000
Total	**$190,200,000**	**$15,000,000**	**$205,200,000**

The individual projects that comprise the 4kV Station Modernization subprogram have their estimates provided in **Section III.B.2.**, however, in summary, the five substations approved by the Stipulation for inclusion in the subprogram have Study level estimates that total $108.0 million as the Base estimate, with $64.2 million currently assigned as R&C. Likewise, the 26kV Station Upgrade project, which anticipates replacement of approximately 40 26kV oil circuit breakers had its Office level estimate approved, which included $25.4 million as the Base estimate with $7.6 million in R&C, for a total estimate of $33.0 million.

Also in September 2022, PSE&G sought URB approval for the authorization of $87.2 million towards the Gas M&R Station Modernization subprogram, including release of $64.6 million in funding. The $64.6 million reflects the total Base estimate from the current Study Level estimates for the four Gas M&R projects, with $22.6 million currently assigned to R&C (individual project estimates are provided in **Section III.C.**). The approved funding split between the IAP Accelerated Recovery and Stipulated Base funds is shown in **Table 4 – Gas M&R Station Modernization URB Approvals**.

Table 4 – Gas M&R Station Modernization URB Approvals

Project	URB Approved Funding		
	IAP Rate Mechanism	Stipulated Base	Total
Gas M&R Station Modernization	$69,800,000	$17,400,000	$87,200,000
Total	**$69,800,000**	**$17,400,000**	**$87,200,000**

A. Key Decisions

To capture formalized key decisions that have an influence on the Program scope or execution, PSE&G continues to utilize a "Record of Decision" (ROD) form that includes a description of the decision, alternatives considered, the decision made, and the rationale for the decision. The RODs are assessed by the IM as they are completed to review their impact, if any, to the Program.

As of the end of 2022, one ROD was completed by PSE&G on the Program titled "Electric Stimulus – Inside Plant." This ROD was actually approved in September 2021, ahead of the Program itself being approved through the Stipulation that had an effective date of July 1, 2022. This ROD was prompted by the determination that the 26kV OCBs and the 4kV station equipment at identified stations (40th Street, McLean Blvd., Teaneck, Tonnelle Ave., and Totowa) had an average 5-year likelihood of failure above the recommendations established in PSE&G's Distribution Planning Criteria. With this determination, PSE&G effectively had two options: 1) a "business as usual" approach using base capital to complete the identified investments as funding allows; or 2) execute this work under an infrastructure investment subprogram.

To evaluate these options, PSE&G engaged Black and Veatch to conduct a cost benefit analysis, which found that following the "business as usual" approach would be more costly due to the additional sequencing required to complete this scope of work, future corrective maintenance costs, future failure costs, and future cost of capital. Overall, Black and Veatch found that the "business as usual" approach would cost 15% higher for the 26kV OCB scope and 30% higher to rebuild the 4kV substations. Thus, based on the identified cost benefits and the qualitative benefits of performing this work, PSE&G selected to proceed with performing this work through the IAP. This ROD effectively established and confirmed the intent and scope for the Substation Modernization subprogram ahead of the Stipulation.

Conclusions

- While this ROD predates the approval of the IAP, it established PSE&G's rationale for selecting the 26kV Station Upgrade and 4kV Station Modernization projects that comprise the Substation Modernization subprogram.
- The cost-benefit analysis performed for PSE&G confirms that executing this work through the IAP is the more cost-effective solution than deferring this work until other funding options are available or the existing equipment fails.

B. Cost Assignments

PSE&G's cost accounting is managed and controlled through SAP, an enterprise planning, accounting, and reporting software system. It is module-based, and the Company uses it as its system tool for general ledger, finance, and accounting/control (but not fixed assets).

PSE&G's accounting practices are subject to Generally Accepted Accounting Principles (GAAP), as well as Federal Energy Regulatory Commission (FERC) practices and relevant instructions as contained in the Uniform Systems of Accounts. In addition, the company is subject to Financial Accounting Standards Board (FASB) pronouncements as they relate to rate regulated entities, and practices accepted and/or mandated by the BPU. Finally, the Company is subject to the Sarbanes-Oxley Act of 2002, and specifically here, section 401, as it relates to accurate recording of fixed asset values. Collectively, this documentation provides the guidance needed to ensure proper accounting treatment.

For placing IAP investments in-service, PSE&G's follows a standard process for determining when an asset is used and useful based on the type of investment, with electric inside plant (IP) and Gas M&R projects having one process and electric outside plant having another, reflective of the types and durations of these projects. These processes are described as follows:

- Electric IP & Gas M&R: when an asset is placed in-service, the project team issues a notification to internal stakeholders and updates the in-service tracker to indicate WBS that should be placed in-service along with the specific timing. This in-service tracker is used to place the WBS components that are listed for that month in-service in SAP.
    - For electric, in-service is identified by the first circuit cutover to put load on the switchgear, with the balance of cutovers treated as direct in-service.
    - For gas, in-service is identified by gas flowing from the transmission system operators through PSE&G's Gas M&R station and into its gas distribution system.
- Electric OP: these investments are universally treated as direct in-service as the construction is completed in under 60 days and the associated assets are energized and carrying load.

There are a variety of general accounting areas the IM will be monitoring arising from the provisions of the Stipulation. These general areas are described in the following subsections.

Findings & Observations:

- In review of PSE&G accounting practices and processes, the IM finds PSE&G's accounting for IAP projects is consistent with past infrastructure investment programs and is in alignment with GAAP, FERC regulations, and other related policies and practices.

1. Costs of Removal (COR)

The Stipulation calls for separate disclosure of COR in each rate adjustment filing and in each 12-month filing as part of the minimum filing requirements. The IM will be reviewing and disclosing charges to COR arising from the Program.

The IM intends to disclose gross COR in its periodic reporting but will track salvage values as well for accounting and ratemaking reconciliation purposes.

2. Construction Work-in-Progress (CWIP)

Proper capitalization of costs covers considerations ranging from when initial capitalization should begin as costs are recorded in Construction Work-in-Progress (CWIP) accounts, to the ultimate transfer of costs to plant-in-service for financial accounting and ratemaking purposes. The IM has reviewed the existence of documentation for each stage in this process, as noted below:

- Most projects begin with preliminary planning work before presentation to the relevant committees in the Company's capital approval process. To qualify as eligible for capitalization, project costs must, among other things, be approved as potentially part of the Company's long-term plan or mandated by regulators and proceed along a path in the capital approval process. If the project is denied at any point, costs are expensed. When the project is ultimately approved, costs incurred are journaled to a CWIP capital account. The account where pending costs are held is reviewed and approved quarterly for disposition. Projects will be charged to or transferred into CWIP if they exceed $5,000 and take in excess of 60 days to complete, among other parameters. This also begins the capitalization of allowance for funds used during construction (AFUDC).

- Once a project is substantially complete and ready for its intended use, or is otherwise energized and carrying load, and/or is considered used and useful, it is transferred out of CWIP to plant-in-service. The responsible operating department notifies the Property Accounting department of the in-service date, and actual costs plus trailing costs are added to plant-in-service. AFUDC also ceases. This is the normal progression for accumulation and disposition of project costs.

Finally, the appropriate costs will be credited to depreciation reserve and debited to depreciable plant. As a result, no gains or losses will be recorded in the retirement of utility plant.

3. Allowance for Funds Used During Construction (AFUDC)

The Stipulation permits recovery of AFUDC on IAP projects in addition to the maximum $351.0 million of costs eligible for recovery under the IAP Rate Mechanism. The Stipulation also stated accrual of AFUDC should be calculated using the same methodology used for other distribution assets and

consistent with Company policy. The IM will be reviewing and disclosing both the amounts of AFUDC accrued and the Company's calculations of the AFUDC rate on an on-going basis.

The Company's practices with respect to AFUDC are in accordance with Electric/Gas Plant Instruction 3(17) of the FERC's Uniform Systems of Accounts prescribed for public utilities (formerly FERC Order 561).

4. Allocated Overheads

The Company follows a philosophy of allocating costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, assigning the costs to individual assets. Where possible, services are charged directly to the entity receiving the benefit based on either fully loaded hourly rates multiplied by the number of hours spent, or through a transactional count multiplied by a predetermined unit cost. Where direct charging is not possible, cost allocations from the Service Company to operating companies are prescribed in a BPU-approved schedule issued pursuant to a BPU order issued in July 2003, as amended by a subsequent BPU order issued in June 2022. The Stipulation calls for the Company to follow its current practices with regard to capitalized costs, including overheads. Cost allocations are performed automatically at each monthly closing within the Company's SAP system.

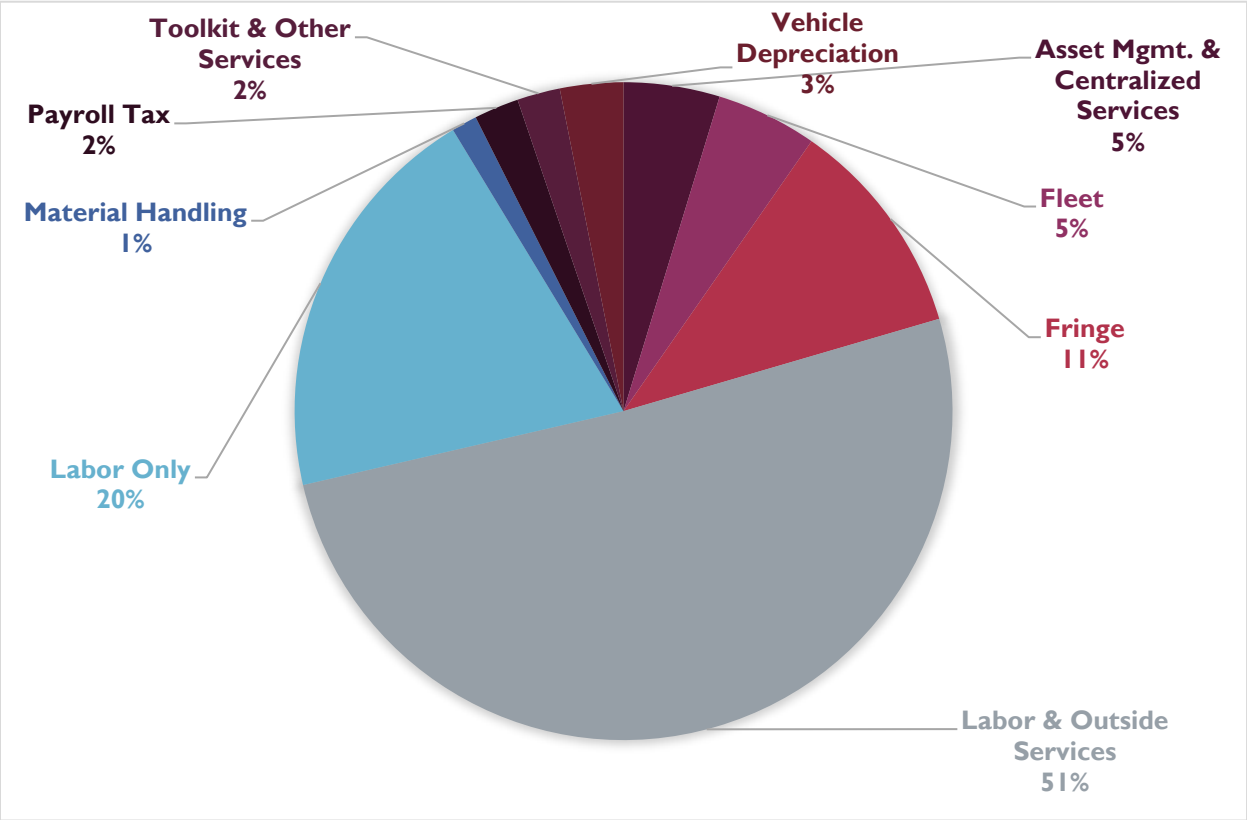
The allocated overheads recorded on the IAP during the third and fourth quarters of 2022 are presented below in **Table 5 – IAP Allocated Overheads as of December 31, 2022**.

Table 5 – IAP Allocated Overheads as of December 31, 2022

Project	Q3 2022	Q4 2022	Total
Electric Outside Plant			
Spacer Cable Conversion	$0	$0	$0
Lashed Cable Replacement	$854	$452,303	$453,157
Spacer Hardware Upgrades	$285	$1,405,342	$1,405,627
CUG Cable Replacement	$1,438	$616,462	$617,900
Voltage Optimization	$285	$52,451	$52,736
Substation Modernization			
26kV Station Upgrade	$0	$163,928	$163,928
4kV Station Modernization	$0	$79,196	$79,196
Gas M&R Station Modernization			
Gas M&R Station Modernization	$0	$52,773	$52,773
Accelerated Recovery Subtotal	*$2,862*	*$2,822,454*	*$2,825,316*
Electric Stipulated Base			
BUD Cable Replacement	$8,975	$288,607	$297,582
Open Wire Secondary Upgrades	$118,586	$4,282,598	$4,401,184
Electric Stipulated Base Subtotal	*$127,560*	*$4,571,205*	*$4,698,765*
Grand Total	**$130,422**	**$7,393,658**	**$7,524,080**

The incurred overheads to date on the IAP align the with total spend on the Program, with the projects having the most total spend to date (Open Wire Secondary Upgrades, Spacer Hardware Upgrades, CUG Cable Replacement, and Lashed Cable Replacement) also incurring the most overheads. In **Figure 2 – Q3-Q4 2022 Allocated Overheads Categorization**, the breakdown of total incurred overheads on the Program in the second half of 2022 by overhead category is provided.

Figure 2 – Q3-Q4 2022 Allocated Overheads Categorization



As shown in **Figure 2**, the overheads incurred on the Program to date have predominantly been associated with labor (either through the Labor & Outside Services category or the Labor Only category, that collectively represent approximately $5.3 million, or 71%, of the $7.5 million in overheads to date).

5. IAP Rate Mechanism vs. Stipulated Base

The full Program as approved through the Stipulation authorized $351.0 million in investments to be made under the IAP Rate Mechanism and $160.0 million in investments within Stipulated Base, for an overall Program budget of $511.0 million. While the individual projects within the Program are generally eligible for spend from either the IAP Rate Mechanism or the Stipulated Base, PSE&G's intent is to apply spend concurrently towards the IAP Rate Mechanism (where applicable) and Stipulated Base, based on project execution plans and available resources. The IM will use this section to highlight the actual spend between these two components of the Program for each of the projects as shown in **Table 6 – IAP Rate Mechanism vs. Stipulated Base Spend as of December 31, 2022**. Note that projects will be added to the Stipulated Base portion of **Table 6** as that spend is incurred and as of the end of 2022 only the BUD Cable Replacement and Open Wire Secondary Upgrades projects had recorded Stipulated Base spend.

Table 6 – IAP Rate Mechanism vs. Stipulated Base Spend as of December 31, 2022

Subprogram/Project	Q3 2022 Actual Costs	Q4 2022 Actual Costs	Total Actual Costs	Budget	Actuals % of Budget
IAP Rate Mechanism					
Electric Outside Plant					
Spacer Cable Conversion	$0	$0	$0	$42,000,000	0%
Lashed Cable Replacement	$1,394	$1,290,876	$1,292,270	$14,000,000	9%
Spacer Hardware Upgrades	$555	$5,222,157	$5,222,712	$15,000,000	35%
CUG Cable Replacement	$4,454	$1,357,373	$1,361,827	$8,000,000	17%
Voltage Optimization	$555	$95,385	$95,940	$12,000,000	1%
Substation Modernization					
26kV Station Upgrade	$0	$607,285	$607,285	$33,000,000	2%
4kV Station Modernization	$0	$585,535	$585,535	$157,200,000	0%
Gas M&R Station Modernization					
Gas M&R Station Modernization	$0	$896,456	$896,456	$69,800,000	1%
IAP Rate Mechanism Total	**$6,958**	**$10,055,067**	**$10,062,025**	**$351,000,000**	**3%**
Stipulated Base*					
Electric Outside Plant					
BUD Cable Replacement	$17,641	$775,754	$793,395	$70,000,000	1%
Open Wire Secondary Upgrades	$175,791	$9,352,498	$9,528,289	$18,000,000	53%
CUG Cable Replacement	$0	$0	$0	$15,000,000	0%
Voltage Optimization	$0	$0	$0	$24,600,000	0%
Substation Modernization					
4kV Station Modernization	$0	$0	$0	$15,000,000	0%
Electric Stipulated Base Total	**$193,432**	**$10,128,252**	**$10,321,684**	**$142,600,000**	**7%**
Gas M&R Station Modernization					
Gas M&R Station Modernization	$0	$0	$0	$17,400,000	0%
Stipulated Base Total	**$193,432**	**$10,128,252**	**$10,321,684**	**$160,000,000**	**6%**

-As the Stipulation only established Stipulated Base funding levels for the electric and gas scopes, without further detail of the electric subprograms/projects, the Stipulated Base budget figures represent the funding levels as approved by PSE&G's URB as discussed within **Section II, with additional detail on the Electric Stipulated Base project costs within **Section III.D.**.*

C. System Performance

The IM scope of work included a task to review and report "On the Impact of the Spacer Cable Conversion, Lashed Cable Replacement, Spacer Upgrade and CUG Cable Replacement Projects on

Overall System Performance during Severe Weather Events." As not every period will be impacted by severe weather events, the review of system performance will also include review of the circuits that have received investments through the IAP in Non-Major Events.

Conclusions

- During this initial Program reporting period of July-December 2022, there were minimal investments completed from which to evaluate performance, including no major events in PSE&G's service territory during this period.
- Despite the limited investments completed, the work completed to date has demonstrated improved circuit performance compared to the recent circuit performance.

1. Major Event Performance

During the current reporting period of July-December 2022, there were no Major Events reported in PSE&G's service territory.

2. Non-Major Event Performance

The performance data for the second half of 2022 for the circuits completed by subprogram are provided below. While there has only been limited work performed on the Program through the end of 2022 and limited actual data to evaluate and compare performance, the actual performance of the few completed circuits reflected better performance than the 5-year SAIDI average.

Spacer Hardware Upgrades

Circuit	5-Year Benchmark SAIDI	Q3-Q4 2022 Performance		
		SAIFI	CAIDI	SAIDI
SPF 8022	0.24229	0.00058	39.36	0.02281

Lashed Cable Replacement

Circuit	5-Year Benchmark SAIDI	Q3-Q4 2022 Performance		
		SAIFI	CAIDI	SAIDI
DUM 4007	0.00743	-	-	-

Note: there was no recorded outage on the DUM 4007 circuit after the investments were completed. DUM 4007 was also selected as part of the Dumont station circuits (also including DUM 4004 and DUM 4005).

Spacer Cable Conversion (Open Wire to Spacer)

No circuits have been completed as of the end of 2022.

CUG Cable Replacement

Circuit	5-Year Benchmark SAIDI	Q3-Q4 2022 Performance		
		SAIFI	CAIDI	SAIDI
RFL 8012	0.10116	0.00007	89.00	0.00612
FMT 8014*	0.02823	-	-	-
FMT 8025*	0.05434	0.00001	19.00	0.00027

Circuit	5-Year Benchmark SAIDI	Q3-Q4 2022 Performance		
		SAIFI	CAIDI	SAIDI
*-Note: prior to a circuit conversion, FMT 8014 was SWT 8001 and FMT 8025 was SWT 8002. The circuit conversion caused the name to change and the previous SAIDI not included in the 5-year benchmark SAIDI data. The 5-year benchmark SAIDI shown in this table reflects the combined data of FMT 8014/SWT 8001 and FMT 8025/SWT 8002.				

III. Subprogram & Project Status

A. Electric Outside Plant

The Electric Outside Plant subprogram features five projects that focus on overhead and underground facilities that supply customers from the substations to the customers' meters, including:

1. Spacer Cable Conversion (also known as Open Wire to Spacer);
2. Lashed Cable Replacement;
3. Spacer Hardware Upgrades;
4. CUG Replacement; and,
5. Voltage Optimization (also known as Capacitor Bank Upgrades).

For planning and execution purposes, PSE&G developed a program execution plan (PEP) for the full Electric Outside Plant subprogram and also included related projects eligible under Electric Stipulated Base in the PEP, including:

1. BUD Cable Replacement; and,
2. Open Wire Secondary Upgrades.

The Electric Outside Plant PEP consolidates the relevant subprogram information, including stakeholder requirements, project descriptions and scopes, benefits and justifications, a subprogram organizational chart, and provides the instructions and processes to be followed for scope and project management. Key aspects of the project management sections of the PEP include:

- Cost Budgeting:
    - Monitor and control overall budget to ensure alignment with the allocated funds and planned spend as well as prudency.
    - The first few circuits for each sub-component will be used as the basis for estimates and to establish an initial baseline. The cost per unit (CPU) will be tracked and updated monthly, with the CPU informing the forecast for the remaining work.
    - Two primary aspects of cost budgeting – the plan, established as part of the annual cost planning process; and the monthly estimate at completion (EAC) forecast, updated based on actuals to date and to-go forecasts. Changes in the cost planning and forecasting will be monitored and controlled at a portfolio level to make sure project expenditures are prudent and within the approved project specific scopes.
    - Each Division will also update the costs per month by considering how many units (miles, sections, devices, etc.) will be engineered and installed each month. Actual cost trends and updated estimates will be incorporated into the forecast.

- Cash Flow Forecasting:
    - Cash flow will indicate the full project cash flow to completion on a monthly basis. Any significant changes or projected changes in contract schedules, payment disbursements, or other financial obligations that can impact the cash flow of the budget will be identified and reported.
    - On a monthly basis, after actuals from the previous period are finalized, the to-go cash flow will be updated. The updated cash flow will be compared to the approved subprogram and Program funding amounts. Where shortfalls exist, efforts will be taken to mitigation such shortfalls, including identifying surpluses that may be used to offset shortfalls.
- Schedule Management:
    - High level subprogram reporting schedule, updated monthly.
    - Tracking high level activities by project in Excel spreadsheets.
- Licensing & Permitting:
    - All permits will be obtained by the respective Division performing the work. Division Engineering groups will determine which permits, if any, are required and make the appropriate applications. Jobs are held until the proper permits are obtained and then turned over to the Division for scheduling and execution of the work.
- Construction:
    - The Program is management centrally, with execution through PSE&G's four electric Divisions and supplemented by contractor resources. The Division departments (Engineering, Overhead Construction, Relay, SCADA, and Operations) work under Division construction procedures and handbooks.
    - Engineers create work packages consisting of sketches, work orders, material requirements, etc. All work packages are reviewed and approved following standard Division engineering processes. Jobs are engineered and reviewed by supervisors and Senior Technicians to ensure the package is ready for construction.
    - Division and PSE&G's Projects & Construction (P&C) supervisors monitor and control construction activities to ensure the work is completed in alignment with PSE&G's safety, engineering, and construction standards.
    - P&C will provide daily oversight of all contractor crews that are supporting the IAP.

The PEP also includes discussion on project authorization, invoice management, quality assurance and quality control, health and safety management, status reporting and communications, contract administration, procurement, commissioning, and project closeout, among other items relevant to the planning, execution, monitoring, and control of the projects.

Conclusions

- The Electric Outside Plant PEP was found by the IM to be complete and in alignment with common industry standards and best practices and provides an appropriate basis from which PSE&G can plan, execute, monitor, and control the Electric Outside Plant projects.

1. Spacer Cable Conversion (Open Wire to Spacer)

"The Company will invest up to $42.00 million to replace aging 3-phase open wire construction (cross arm and armless) with new spacer cable type construction. Spacer cable is a more compact and reliable design that incorporates a conductor with a thick polymer covering, thereby making it especially resilient to branch and tree contacts." (IAP Stipulation)

In planning for the Spacer Cable Conversion work, the prioritization criteria established by PSE&G for this scope of work is based on a calculated ranking using:

- Open wire construction and tree cause codes only; and,
- Updated cost-benefit data from the prior seven years (2016-2022).

By utilizing reliability data for the prior seven years, it allows PSE&G to have a common circuit list for the similar work carried out under the Energy Strong 2 Electric Stipulated Base Outside Plant-Higher Design Standards (OP-HDS) work. PSE&G's initial plan is to execute these projects beginning in 2024 carrying through to the Program end date in June 2026, as such there has been no work performed on these projects and no costs incurred through the end of 2022.[1]

The list of circuits identified for Spacer Cable Conversion projects and the 5-year average CAIDI and SAIFI for each circuit is shown below in **Table 7 – Spacer Cable Conversion Circuit Metrics**.

Table 7 – Spacer Cable Conversion Circuit Metrics

Circuit	CAIDI		SAIFI	
	Non-Major Event 5-Yr. Avg.	Tree-Related Event 5-Yr. Avg.	Non-Major Event 5-Yr. Avg.	Tree-Related Event 5-Yr. Avg.
LEV 8004	120.62	159.34	0.00069	0.00038
MAD 8033*	78.41	128.93	0.00053	0.00018
LAW 8025*	89.78	188.73	0.00096	0.00008
CIN 8011	75.88	180.61	0.00097	0.00012
LUM 8011*	86.53	27.21	0.00047	0.00003
LEV 8005	76.63	130.39	0.00153	0.00066
CUT 8043	81.17	171.76	0.00161	0.00023
CLK 8015*	77.76	171.27	0.00125	0.00077
HID 8044*	81.96	200.41	0.00156	0.00038
THY 4009	1.80	1.80	0.00011	0.00011
LEV 8001	85.97	101.23	0.00205	0.00116
CRX 8006	49.85	64.66	0.00110	0.00020

[1] Note: in early 2023, PSE&G made the decision to transition the Open Wire to Spacer work initially planned for the Energy Strong 2 Program to the IAP due to limited funding available in the Electric Stipulated Base portion of the Energy Strong 2 Program. Thus, Spacer Cable Conversion work will now commence in 2023 instead of the originally planned 2024. Later in 2023, six of the circuits identified were re-transitioned back to the Energy Strong 2 Program based on available funding.

Circuit	CAIDI		SAIFI	
	Non-Major Event 5-Yr. Avg.	Tree-Related Event 5-Yr. Avg.	Non-Major Event 5-Yr. Avg.	Tree-Related Event 5-Yr. Avg.
LAW 8026*	113.29	89.73	0.00082	0.00044
CIN 8034	80.19	58.16	0.00069	0.00002
EAT 8011	68.93	139.02	0.00094	0.00006
KIN 8015	117.40	184.80	0.00084	0.00003
THY 4004	80.24	88.21	0.00036	0.00014
TUR 8025	54.53	111.00	0.00102	0.00025
MTL 8021	110.84	81.61	0.00009	0.00000
WAD 8014	171.67	141.77	0.00054	0.00029
BUS 8014	117.68	51.13	0.00035	0.00007
ALD 8013	42.39	39.51	0.00075	0.00003
LEV 8010	116.80	148.02	0.00099	0.00046
CUT 8007	67.77	125.14	0.00123	0.00018
MRO 8012	106.68	104.34	0.00088	0.00065
CRX 8002	65.38	71.11	0.00087	0.00033
FAV 4004	97.31	0.00	0.00023	0.00000
MDF 8013	60.17	75.32	0.00115	0.00051

**-These circuits were removed from the IAP and re-included as part of the Energy Strong 2 Program in the fourth quarter of 2023 based on available funding in the Energy Strong 2 Program (note: the Space Cable Conversion projects utilize the same circuit selection criteria as the Outside Plant-Higher Design Standards (OP-HDS) work within the Electric Stipulated Base portion of the Energy Strong 2 Program).*

Conclusions

- While minimal work has been performed to date on the Spacer Cable Conversion project, the IM finds the prioritization criteria established by PSE&G for individual project selection is an appropriate basis from which to select projects as it focuses on outages driven by tree contact, which this type of investment is intended to alleviate by making that cable more resilient, and further by using updated cost-benefit data to support cost effectiveness in delivering this scope of work.

2. Lashed Cable Replacement

"The Company will invest up to $14.00 million to replace lashed cable with spacer cable construction. Lashed primary cable consists of three (3) conductors that are wrapped together with a bonding ribbon and suspended from pole to pole with clamps. This construction type is used for 4kV applications primarily in urban areas, backyards, or right of ways with limited construction space. Lashed cable is one of the oldest distribution assets on PSE&G's system." (IAP Stipulation)

In planning the Lashed Cable Replacement projects, the prioritization criteria established by PSE&G for this scope of work is based on a calculated ranking using:

- Lashed cable cause codes only; and,
- Updated cost-benefit for the prior five years (2018-2022).

The prioritization criteria also uses updated circuit miles to reflect only lashed cable construction in lieu of the entire circuit mileage (used on the original circuit list in the IAP filing). This also resulted in two circuits being removed from the Program, with OAK 4008 having received upgrades outside of the IAP and MCL 4007 unlikely to be completed in the Program based on current cost forecasts and the priority of this circuit on the overall list. Identified circuits are then grouped by station to determine the overall cost-benefit and to gain efficiencies while taking outages since the circuit lengths are relatively short. A photo example of the lashed cable work is provided below in **Figure 3 – Lashed Cable Photo Example**.

Figure 3 – Lashed Cable Photo Example

Following the commencement of the Program in July 2022, PSE&G commenced engineering on the initial set of circuits selected to receive investments under the Lashed Cable Replacement project. As of the end of 2022, engineering packages were prepared for 15 circuits, with two commencing construction, and one of those being completed and placed in-service in November 2022 (circuit DUM 4007 in the Palisades Division). The current status of the Lashed Cable Replacement project is provided below in **Table 8 – Lashed Cable Replacement Project Status as of December 31, 2022**.

Table 8 – Lashed Cable Replacement Project Status as of December 31, 2022

Target # of Circuits	Target # of Miles	Engineering Packages Complete	Construction Started	In-Service	Total Miles In-Service
		(# of circuits)			
TBD	14	15	2	1	0.30

Of the 15 engineering packages completed as of the end of 2022, the circuits and their respective estimated mileage, project budget, and 5-year average CAIDI and SAIFI metrics are provided below in **Table 9 – Lashed Cable Replacement Project Detail**.

Table 9 – Lashed Cable Replacement Project Detail

Circuit	Estimated Mileage	5-Year Avg. CAIDI	5-Year Avg. SAIFI	Project Budget
DUM 4004	0.31	3.40	0.00003	$306,104
DUM 4005	0.57	79.00	0.00012	$569,748
DUM 4007	0.30	111.60	0.00014	$301,261
FIF 4002	0.16	60.75	0.00094	$455,657
MCL 4007	0.20	57.75	0.00061	$195,496
MCL 4008	1.17	3.77	0.00008	$1,174,619
MOG 4003	0.12	38.47	0.00094	$85,905
ORA 4001	0.20	180.09	0.00088	$222,340
ORA 4002	0.25	178.04	0.00025	$222,340
VNH 4008	0.36	91.29	0.00012	$363,888
WAV 4006	0.10	6.14	0.00001	$49,355
WAV 4013	0.15	38.20	0.00002	$147,388
WAV 4015	0.14	58.61	0.00073	$138,080
WAV 4017	0.20	11.00	0.00003	$204,527
WAV 4018	0.47	108.80	0.00090	$472,197

The forecasted and actual costs by period are shown below as compared to the current URB approved budget for the project in **Table 10 – Lashed Cable Replacement Project Costs as of December 31, 2022**. As of December 2022, the forecast reflected the work planned for 2022 only as PSE&G continued to develop and plan the work for the full Program.

Table 10 – Lashed Cable Replacement Project Costs as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Forecast	Budget
Central	$139	$48,566	$48,705	*Division forecasts under development*	$14,000,000
Metro	$978	$148,012	$148,990		
Palisades	$139	$1,077,576	$1,077,714		
Southern	$139	$16,722	$16,861		
Total	**$1,394**	**$1,290,876**	**$1,292,270**	**$14,000,000**	**$14,000,000**
% of Actuals to Forecast & Budget				**9%**	**9%**

As shown in **Table 10**, the bulk of the actual costs to date has occurred in the Palisades Division, which reflects the outcome of the initial prioritization for project selection and the availability of the Division to start on the work. Additionally, for the one circuit completed as of the end of 2022 (DUM 4007), its estimated cost was $301,261 and actual costs for this circuit were approximately $972,530.

As of the end of 2022, PSE&G is forecasting that the final Lashed Cable Replacement projects will go in-service in June 2026.

Conclusions

- The prioritization criteria established by PSE&G for the Lashed Cable Replacement projects is an appropriate basis to plan the work as it targets the circuits that had outages stemming from

lashed cable. By using updated cost-benefit data and grouping the projects by station should provide cost effectiveness in delivering this scope of work.

- Using updated circuit miles to show only lashed cable construction in lieu of the entire circuit mileage (used on the original circuit list in the IAP filing) is appropriate way to track the work and more accurately capture the investments made.

3. Spacer Hardware Upgrades

"The Company will invest up to $15.00 million to replace aging spacer components along existing construction with new hardware that is designed to a higher and more resilient standard. The new spacer standard has higher insulation values, improved material properties and better mechanical performance, and is expected to improve the reliability on these circuits at a relatively low cost compared to circuit construction." (IAP Stipulation)

The circuits identified by PSE&G for the Spacer Hardware Upgrades are based on the original circuit list included in the IAP filing with the prior year's SAIFI ratings providing the prioritization criteria from that list. Planning for this work begins with an evaluation of the identified circuits, looking at the end-to-end condition and identifying the required components. Execution of this work is being performed by a contractor that was awarded through a competitive bid process.

The bid process for the Spacer Hardware Upgrades work followed standard PSE&G procurement processes and included bids received from five contractors. PSE&G's bid evaluation considered technical considerations, such as bid package completeness, technical exceptions, and safety and experience, and commercial considerations, namely pricing. The selected contractor had the third lowest evaluated price, though other lower price bidders were removed from consideration as they were being considered for award for PSE&G's Defective Pole Replacement Program. PSE&G's contract strategy for these scopes was to award this IAP work and the Defective Pole Replacement Program (which was split into a north territory and south territory scope) to three separate contractors in order to maintain diversity in its supplier utilization. In addition, the IAP scope is much smaller than the Defective Pole Replacement Program, which will also allow the selected IAP contractor the opportunity to continue to develop and become a more experienced overhead contractor for PSE&G.

In receiving URB approval for the Spacer Hardware Upgrades project (discussed in **Section II**), PSE&G initially assumed the total scope would contemplate approximately 300 circuit miles, which is dependent on the cost variations driven by existing field conditions encountered (e.g. damaged cross arms, missing ground wires, etc.) and other location-specific drivers, such as the distinct traffic control requirements of each local jurisdiction in which these projects are being executed. As of the end of 2022, PSE&G updated its assumption based on revised estimates and initial actual costs data to reflect a current scope of approximately 125 circuit miles and since the start of the Program through the end of 2022, 22.5 circuit miles have received Spacer Hardware Upgrades. The current list of circuits targeted for Spacer Hardware Upgrades is provided below in **Table 11 – Spacer Hardware Upgrades Circuit Detail**.

Table 11 – Spacer Hardware Upgrades Circuit Detail

Division	Station	Circuit	Circuit Mileage
Central	Aldene Sub	ALD 8023	6.39
Central	Aldene Sub	ALD 8016	5.14
Central	Aldene Sub	ALD 8025	4.73
Central	Doremus Place	DOR 8034	4.93
Central	Doremus Place	DOR 8035	4.18
Central	Doremus Place	DOR 8044	1.40
Central	Green Brook	GBK 8021	7.71
Central	Meadow Road	MEA 8026	6.68
Central	Minue Street	MIN 8013	4.65
Central	Springfield Road	SPF 8022	3.71
Central	Springfield Road	SPF 8013	5.27
Central	Warinanco	WAN 8011	5.50
Metro	Cedar Grove	CED 8022	5.66
Metro	Cedar Grove	CED 8011	2.10
Metro	Clifton	CLF 8022	3.90
Metro	Clifton	CLF 8024	4.78
Metro	Cook Rd	COR 8044	1.64
Metro	Hawthorne	HAW 8032	5.47
Metro	Jackson Rd	JAC 8032	5.14
Metro	Kuller Road	KUL 8022	2.62
Metro	Laurel Ave	LAU 8011	2.99
Metro	Laurel Ave	LAU 8036	3.91
Metro	Marion Drive	MAI 8012	1.51
Metro	Marion Drive	MAI 8011	3.80
Metro	West Caldwell	WEW 8021	5.65
Palisades	Hillsdale	HID 8044	6.32
Palisades	Kingsland	KIN 8025	3.20
Palisades	Leonia	LEO 8041	5.95
Palisades	Leonia	LEO 8005	3.60
Palisades	Maywood	MAY 8015	4.08
Palisades	New Milford	NEW 8031	5.03
Palisades	Ridgefield	RFL 8043	3.96
Palisades	Ridgefield	RFL 8035	0.71
Palisades	Ridgefield	RFL 8024	2.49
Palisades	Saddle Brook	SAD 8034	2.20
Palisades	Saddle Brook	SAD 8044	1.01
Southern	Deptford	DFD 8007	3.30

The forecasted and actual costs by period are shown below as compared to the current URB approved budget for the project in **Table 12 – Spacer Hardware Upgrades Project Costs as of December 31, 2022**.

Table 12 – Spacer Hardware Upgrades Project Costs as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Forecast	Budget
Central	$139	$1,497,781	$1,497,920	$4,169,178	$15,000,000
Metro	$139	$856,829	$856,967	$4,052,084	
Palisades	$139	$2,670,108	$2,670,246	$6,016,655	
Southern	$139	$197,439	$197,578	$762,089	
Total	**$555**	**$5,222,157**	**$5,222,712**	**$15,000,006**	**$15,000,000**
% of Actuals to Forecast & Budget				**35%**	**35%**

As of the end of 2022, one circuit within the Spacer Hardware Upgrade projects was completed, SPF 8022, which upgrades to 3.71 circuit miles and had an estimated cost of $683,612 compared to actual costs of $629,063. The individual Division forecasts shown in **Table 12** reflects the location of the circuits on the original circuit list, which had few circuits in the Southern Division. As of the end of 2022, PSE&G is forecasting that the final Spacer Hardware Upgrade projects will go in-service in June 2024.

Conclusions

- Starting with the original circuit list and prioritizing based on the prior year's SAIFI ratings is an appropriate method to prioritize the work to provide a structure on which the investments are most likely to have reliability improvements.

4. Conventional Underground (CUG) Cable Replacement

"The Company will invest up to $8.00 million to replace the poorest performing conventional underground cables that have reached end of life. Conventional underground cable systems are most common in urban environments, and this asset class includes cable, splices, and terminations." (IAP Stipulation)

The prioritization criteria established by PSE&G for the CUG Cable Replacement projects is based on a calculated ranking using:

- CUG cause codes only;
- Focused on the 10% poorest performing circuits (number of incidents and minutes) for the prior five years (2018-2022);
- 5-year average faults per mile; and,
- 5-year average customer minutes interrupted.

From the start of the Program through the end of 2022, the primary actions on this project involve manhole inspections, which to date have identified minimal required modifications. As of the end of

2022, approximately one mile of cable had been replaced out of a forecasted scope of 34 miles, with three circuits completed and in-service (SWT 8002, SWT 8001, and RFL 8012). PSE&G has observed minor material shortages for these projects, but does not anticipate impacts from these shortages as the resources that perform this work are generally working higher priority jobs at this time. In the interim, PSE&G is also evaluating other procurement options for the cable to ensure the availability meets the needs of the Program.

The estimated and actual costs of the three circuits placed in-service as of the end of 2022 are provided below in **Table 13 – CUG Cable Replacement Completed Project Estimated vs. Actual Costs as of December 31, 2022**.

Table 13 – CUG Cable Replacement Completed Project Estimated vs. Actual Costs as of December 31, 2022

Circuit	Miles Replaced	Estimate	Actual Cost	Variance
RFL 8012	0.06	$72,449	$57,131	($15,318)
FMT 8014	0.14	$102,284	$120,500	$18,216
FMT 8025	0.03	$45,103	$66,896	$21,793

In **Table 14 – CUG Cable Replacement Costs as of December 31, 2022** the breakdown of actual costs incurred by Division is provided compared to the current forecasts.

Table 14 – CUG Cable Replacement Costs as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Cost	Total Forecast	Budget*
Central	$0	$140,833	$140,833	$2,352,203	$23,000,000
Metro	$0	$790,290	$790,290	$15,947,218	
Palisades	$2,227	$294,261	$296,488	$2,436,161	
Southern	$2,227	$131,989	$134,216	$2,264,418	
Total	**$4,454**	**$1,357,373**	**$1,361,827**	**$23,000,001**	**$23,000,000**
% of Actuals to Forecast & Budget				**6%**	**6%**
**-Includes $8.0 million under the IAP Rate Mechanism and $15.0 million under Stipulated Base.*					

As indicated in **Table 14**, the majority of the CUG Cable Replacement work will be within the Metro Division, reflecting this Division having the most underground cable. As of the end of 2022, PSE&G is forecasting that the final CUG Cable Replacement projects will go in-service in June 2026.

Conclusions

- The prioritization criteria established by PSE&G for the CUG Cable Replacement scope is an appropriate basis to identify and the select the poorest performing circuits to receive these investments.
- Material shortages have been identified as a risk, but have not had a material impact on the project at this time and PSE&G is evaluating alternative procurement options to mitigate this risk.

5. Voltage Optimization (Capacitor Bank Upgrades)

"The Company will invest up to $12.00 million to replace aging 13kV pole top capacitors and switches that are increasingly failing and providing poor voltage regulation.." (IAP Stipulation)

The aging pole top capacitors and switches being replaced through this project will be replaced with digital capacitors that provide real-time data (compared to the existing analog devices that have no direct method to determine statuses).

The prioritization criteria established by PSE&G for the Voltage Optimization projects beings with the list of stations identified in the IAP filing, with PSE&G planning to select at least one station from each Division and complete all capacitors from the selected stations (no partial networks). The initial stations selected for capacitor bank upgrades include: Kilmer – 110 capacitors (Central Division); Levittown – 141 capacitors (Southern Division); Pierson – 60 capacitors (Central Division); Saddle Brook – 101 capacitors (Palisades Division); and West Caldwell – 97 capacitors (Metro Division). The total number of stations ultimately included in the Program will be determined by the actual costs incurred against the Stipulation budget (including Stipulated Base funding), though at this time the list of stations identified in PSE&G's IAP filing (within Schedule EFG-IAP-11) remains current for the targeted stations. In receiving URB approval for the Voltage Optimization projects (discussed in **Section II**), PSE&G assumed approximately 1,050 pole tap capacitors and switches will be replaced through the IAP. Based on revised estimates developed since that time, PSE&G updated its assumptions and revised the estimated scope to 504 capacitors. The main drivers to the updated cost estimate and resulting reduction in number of planned capacitors for the Program includes current vendor pricing and actual costs per unit observed in similar work (such as recloser installations).

In the fourth quarter of 2022, PSE&G initiated sample power factor testing on identified stations for optimization modeling. A pilot installation was performed in December 2022 on the LEV 8002 circuit ahead of the execution of the full scope of work. This pilot project included the engineering, procurement, equipment installation, and functional testing on the circuit. PSE&G also finalized the procurement package for the Voltage Optimization projects, with the material for these projects is expected to be received in the second half of 2023, delivery of which will inform the execution strategy for this work.

In **Table 15 – Voltage Optimization Costs as of December 31, 2022** the breakdown of actual costs incurred by Division is provided compared to the current forecasts.

Table 15 – Voltage Optimization Costs as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Budget*
Central	$139	$30,053	$30,192	$9,214,600	$36,600,000
Metro	$139	$7,432	$7,571	$9,260,550	
Palisades	$139	$7,194	$7,332	$9,124,919	
Southern	$139	$50,706	$50,845	$8,999,927	
Total	**$555**	**$95,385**	**$95,939**	**$36,599,996**	**$36,600,000**
% of Actuals to Forecast & Budget				**0%**	**0%**
**-Includes $12.0 million under the IAP Rate Mechanism and $24.6 million under Stipulated Base.*					

The minimal amount of costs incurred through the end of 2022 reflects the work performed to date, which as noted above involved the commencement of sample power factor testing and the execution of the pilot project. As of the end of 2022, PSE&G is forecasting that the final Voltage Optimization projects will go in-service in June 2026.

Conclusions

- Performing a pilot project ahead of the full scope of work allows PSE&G to validate and/or update its planning assumptions to support efficient execution of the full scope.

B. Substation Modernization

As of the end of 2022, the PEP for the Substation Modernization subprogram was still being developed by PSE&G. The IM will review and report on it in a future report, similar to the Electric Outside Plant PEP discussed in **Section III.A.** of this report.

1. 26kV Station Upgrade

"The Company will invest up to $33.00 million to replace existing 26kV oil circuit breakers ('OCBs') with newer gas circuit breakers at various switching and substations across the Company's system. The OCBs have an average age of 60 years, require significant corrective maintenance, and pose environmental challenges." (IAP Stipulation)

PSE&G anticipates this scope of work will feature the replacement of approximately 40 26kV OCBs at various switching stations and substations. Stations were selected for inclusion in this subprogram based on an analysis utilizing criteria including equipment age and condition, maintenance costs, and if station upgrades were planned within the next 10 years (if so, such stations were removed from consideration). During the design and planning process, field inspections are performed at the stations to identify and assess any aspects of the station that could influence the quality of breaker performance (disconnect switches, protective relays, etc.) with the station-specific scope adjusted based on this review. While the upgrades are planned to be implemented following the completion of the total station-specific design, breaker failures can and have occurred, which prompts PSE&G to advance the engineering to complete the replacement of the failure breaker earlier than planned to return the station to service. Under these scenarios, only the equipment that fails is initially replaced, which allows the return to service to occur as soon as possible, but does not complete the full scope of the station.

In September 2022, PSE&G submitted the Office level estimate for the 26kV Station Upgrade scope of work, which included $25.4 million as a Base estimate and $7.6 million in R&C, for a total of $33.0 million, aligned with the Stipulation budget. Since the IAP filing, PSE&G reviewed and updated its list of stations to receive 26kV Station Upgrades with stations that have planned upgrades over the next 10 years removed from the Program and replaced with additional stations that meet the age and condition criteria used for the original list (in addition to not having planned upgrades in the near future). **Table 16 – Original vs. Current 26kV Station Upgrade Projects** below summarizes the changes from the scope as of the IAP filing to the current scope for these projects. Overall, the original IAP filing scope for the 26kV Station Upgrade projects identified 40 breakers at 14 stations while the current scope includes 36 breakers at 17 stations.

Table 16 – Original vs. Current 26kV Station Upgrade Projects

Station	Breakers	Status
Arcola	1	Part of IAP filing, remains in Program.
Athenia	1	In IAP filing was identified with 5 circuits, since then a new non-IAP project was developed that removed 4 breakers from the scope. Prior to this plan being developed, one breaker at Athenia failed that was replaced under the IAP.
Bloomfield	8	Part of IAP filing, remains in Program.
Bound Brook	4	Added to Program after IAP filing.
Brunswick	1	Part of IAP filing, remains in Program.
Burlington	1	Part of IAP filing, remains in Program.
Camden	4	Removed from Program due to planned upgrades within next 10 years.
Cherry Hill	1	Part of IAP filing, remains in Program.
Chester	1	Part of IAP filing, remains in Program.
Clark	2	Added to Program after IAP filing.
Culver Avenue	2	Part of IAP filing, remains in Program.
Haddon Heights	1	Part of IAP filing, remains in Program.
Haldeon	2	Added to Program after IAP filing.
Henry Street	2	Added to Program after IAP filing.
Lawrence	6	Removed from Program due to planned upgrades within next 10 years.
Mechanic	2	Added to Program after IAP filing.
Metuchen	6	Removed from Program due to planned upgrades within next 10 years.
Princeton	2	Part of IAP filing, remains in Program.
Raritan Valley	2	Added to Program after IAP filing.
South Orange	1	Added to Program after IAP filing.
Westwood	2	Part of IAP filing (1 breaker), remains in Program (updated to 2 breakers).

During the fourth quarter of 2022, engineering commenced on the first four OCB replacements, with one project advancing at each of PSE&G's four Divisions. By the end of 2022, engineering was completed on three of these four projects, with the one OCB replacement at the Athenia substation installed in December 2022 that was a breaker failure replacement, with the remaining scope to be completed in the fall of 2023. PSE&G also confirmed with the IM that it currently has adequate inventory in stock to support the project needs.

In **Table 17 – 26kV Station Upgrade Costs as of December 31, 2022** below, the total actual costs incurred through the end of 2022 are shown compared to the current forecast and budget.

Table 17 – 26kV Station Upgrade Costs as of December 31, 2022

Project	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Budget
Total	**$0**	**$607,285**	**$607,285**	**$33,000,000**	**$33,000,000**
% of Actuals to Forecast & Budget				**2%**	**2%**

As of the end of 2022, PSE&G is forecasting that the final 26kV Station Upgrade projects will go in-service in May 2026.

Conclusions

- The criteria used for selecting 26kV stations to receive IAP investments appropriately considers the age and maintenance cost of the station equipment and if the station is already scheduled to receive upgrades.
- While PSE&G develops engineering packages for each station, partial scopes of work may be executed to address equipment failures at particular stations. In these scenarios, the focus is on returning the station to service, meaning the remaining scope will be performed at a later time following the completion of engineering.
- As of the end of 2022, one OCB had been replaced out of an assumed scope of 40 OCBs. The unit replaced was at the Athenia switching station and was an emergency replacement for the failed equipment, which was on the IAP priority list for replacement.

2. 4kV Station Modernization

"The Company will invest up to $157.2 million to modernize 4kV switchgear at certain electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure. The following five (5) substations are included within the Project:

- *Fortieth Street*
- *McLean Blvd*
- *Teaneck*
- *Tonnelle Ave*
- *Totowa"*

(IAP Stipulation)

For the five projects identified in the Stipulation for the 4kV Station Modernization scope, PSE&G submitted Study level estimates to its URB for approval in September 2022. The scope description and estimate for each of these projects is provided in **Table 18 – 4kV Station Modernization Scope and Study Level Estimates**.

Table 18 – 4kV Station Modernization Scope and Study Level Estimates

Project	Scope	Estimate (Base)
40th Street	Replace existing 4kV feeder rows with 10 circuit breakers and a half aisle switchgear with associated voltage regulators and reactors feeder rows, two transformer breakers, construction two 4kV capacitor banks, and eliminate obsolete 4kV equipment.	$19,200,000
McLean Blvd	Replace existing 4kV feeder rows with a two-tier assembly including: an 18 breaker ring bus installed on the second story to include three transformer breakers, 14 feeder rows installed at grade level, and elimination of obsolete 4kV equipment.	$23,800,000
Teaneck	Replace existing 4kV feeder rows with a two-tier assembly including: an 18 breaker ring bus installed on the second story to include three transformer	$23,500,000

Project	Scope	Estimate (Base)
	breakers, 14 feeder rows installed at grade level, and elimination of obsolete 4kV equipment.	
Tonnelle Ave	Offload existing station with a contingency set up of two units subs and install new 4kV eight circuit breaker and a half sheltered-aisle switchgear with eight associated voltage regulators and reactor feeder rows and three 4kV dedicated transformer head breakers, and elimination of obsolete 4kV equipment.	$18,100,000
Totowa	Replace existing 4kV feeder rows with a 10 circuit breaker and half-aisle switchgear with associated voltage regulators and reactor feeder rows, two transformer breakers, and elimination of obsolete 4kV equipment.	$23,400,000
R&C/Placeholder	R&C for the subprogram	$64,200,000

Beyond the projects listed above, the URB submittal also approved $64.2 million as a placeholder/R&C funds for the 4kV Station Modernization scope of work, which includes $15.0 million in Stipulated Base funding and $49.2 million through the IAP Rate Mechanism.

In **Figure 4 – 4kV Station Modernization Project Status as of December 31, 2022** below, a high-level summary of the major project activities for each project are shown with the planned durations.

Figure 4 – 4kV Station Modernization Project Status as of December 31, 2022

Project	Status Point	2022		2023				2024				2025				2026		Program End Date - June 30, 2026
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	
40th Street	**Dec. 2022**			DR					C					IS		CO		
McLean Blvd.	**Dec. 2022**			DR				C				IS	CO					
Teaneck	**Dec. 2022**			DR				C				IS	CO					
Tonnelle Ave.	**Dec. 2022**			DR							C		IS		CO			
Totowa	**Dec. 2022**		DR						C					IS		CO		
Legend: DR = Key Drawing Review; C = Construction; IS = Fully In-Service (major assets in-service); CO = Closeout																		

As shown in **Figure 4**, for most of 2023, the primary activities on the 4kV Station Modernization projects will be the advancement of engineering and long-lead procurement activities ahead of the start of construction in 2024. The next major milestone for the five 4kV Station Modernization projects will be the issuance of the switchgear PO in the first quarter of 2023. In preparing the switchgear procurement, PSE&G implemented lessons learned from its Energy Strong 2 Program experience such as incorporating progress milestone payments on the switchgears and will continue to have regular meetings with its vendors (PSE&G is using Powell and Powercon as the switchgear vendors). The forecasted in-service dates for the 4kV Station Modernization projects are all within 2025, with four of the five projects projected for a first quarter 2025 in-service date and the other projected for a fourth quarter 2025 in-service date.

During the second half of 2022, detailed engineering commenced on the 40th Street and Totowa projects, both of which are using internal PSE&G resources for the engineering scope. For the other three projects (McLean Blvd., Teaneck, and Tonnelle Avenue), PSE&G intends to issue POs for the detailed engineering scope in the first quarter of 2023. Use of internal versus external engineering

resources on these projects is determined by the project's scope, complexity and the availability of internal resources. For McLean Blvd. and Teaneck, the design involves an over/under concept with the switchgear installed above the feeder rows due to the very tight site space available. In preparing these projects, PSE&G's team reviewed the Energy Strong 2 Plainfield project, which has a similarly small site and over/under design concept and utilized the same A/E as the McLean Blvd. and Teaneck projects (Black and Veatch). In addition to the site space restrictions, another challenge to the execution of these projects is the requirement for contingency plans for four of the five stations (all but 40th Street, which will require reconfiguration outside the station) to allow portions of the stations to remain in-service while the work is carried out.

In **Table 19 – 4kV Station Modernization Costs as of December 31, 2022** below, the actual costs incurred through the end of 2022 are shown for each project compared to the current forecasts.

Table 19 – 4kV Station Modernization Costs as of December 31, 2022

Project	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Budget*
40th Street	$0	$169,958	$169,958	$19,003,700	$19,200,000
McLean Blvd.	$0	$65,861	$65,861	$22,968,575	$23,800,000
Teaneck	$0	$87,612	$87,612	$22,730,454	$23,500,000
Tonnelle Ave.	$0	$70,678	$70,678	$18,156,804	$18,100,000
Totowa	$0	$191,426	$191,426	$18,214,557	$23,400,000
R&C/Placeholder	-	-	-	-	$64,200,000
Total	**$0**	**$585,535**	**$585,535**	**$101,074,091**	**$172,200,000**
% of Actuals to Forecast & Budget				**1%**	**0%**
**-Includes $157.2 million under the IAP Rate Mechanism and $15.0 million under Stipulated Base.*					

Conclusions

- Through the end of 2022, only preliminary work has commenced on the 4kV Station Modernization subprogram. However, PSE&G's planning for this work has appropriately considered the experience from similar work carried out under the Energy Strong 2 Program.

C. Gas M&R Station Modernization

"In the Gas Metering and Regulating ('M&R') Station Modernization Subprogram, PSE&G will modernize its M&R stations by phasing out outdated designs, upgrading stations to series regulation design with a second level of overpressure protection for enhanced safety and reliability, and replacing aging equipment and facilities. The Company will make up to $69.80 million of Program investment to comply with U.S. Department of Homeland Security Transportation Security Administration regulations, as well as, toward modernizing the following four (4) M&R stations:

- *Brooklawn*
- *Hillsborough*
- *Hamilton*
- *Hanover"*

(IAP Stipulation)

"The Company shall spend a total of $160 million on certain capital projects during the Program term that will not be recovered through the IAP Rate Mechanism… The remaining $17.4 million [after accounting for the Electric Stipulated Base portion] *will be used to complete any of the gas M&R station upgrades specified above in Paragraph 8* [the four stations listed in the Gas M&R Station Modernization subprogram, plus Trenton, Roseland, and West Deptford]."
(IAP Stipulation)

As shown in the above excerpts from the Stipulation, the IAP Rate Mechanism portion of the Gas M&R Station Modernization budget was established at $69.8 million, which is to be applied toward modernizing the four gas M&R stations identified in the Stipulation. The $17.4 million portion of the Stipulated Base allocated for the Gas M&R Station Modernization efforts indicated it would be used towards the completion of the initial four stations and/or for three additional stations identified. Given the overlapping nature of the IAP Rate Mechanism and the Stipulated Base portions of the Gas M&R work within the Program, the IM will report on the Gas M&R projects collectively under this section, while also indicating the split in spend between the IAP Rate Mechanism and the Stipulated Base.

In **Figure 5 – Gas M&R Station Modernization Project Status as of December 31, 2022** below, a high-level summary of the major project activities for each project are shown with the planned durations.

Figure 5 – Gas M&R Station Modernization Project Status as of December 31, 2022

Project	Status Point	2022		2023				2024				2025				2026		Program End Date - June 30, 2026
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	
Brooklawn	Dec. 2022			DD					C		IS		CO					
Hillsborough	Dec. 2022			DD					C		IS		CO					
Hamilton	Dec. 2022			DD								C			IS		CO	
Hanover	Dec. 2022			DD									C		IS		CO	
Legend: DD = Detailed Design; C = Construction; IS = Fully In-Service (major assets in-service); CO = Closeout																		

As shown in **Figure 5**, PSE&G has planned the execution of the Gas M&R projects such that each project will commence detailed design early in 2023, with Brooklawn and Hillsborough planned to advanced to construction in the second quarter of 2024 and going in-service by the end of 2024, followed by Hamilton and Hanover going into construction in early 2025 ahead of their forecasted in-service dates late in 2025.

During the second half of 2022, PSE&G had completed review of the preliminary design drawings and P&IDs for each of the Gas M&R stations. The bidding process for the A/E work associated with each of the projects was also initiated in the second half of 2022, with award of the A/E contracts planned for early 2023. As of the end of 2022, the PEP for the Gas M&R Station Modernization subprogram was still being developed by PSE&G, the IM will review and report on it in the next quarterly report, similar to the Electric Outside Plant PEP discussed in **Section III.A.** in this report.

Following the experience of the Gas M&R subprogram within the Energy Strong 2 Program, PSE&G has implemented various lessons learned in its approach to the Gas M&R projects within the IAP, including:

- Conducting an upfront investigation of existing conditions at each site, including a buildings hazardous assessment, Geotech soil borings, gathering as-built drawings, and verifying NJDEP flood area regulations (these stations are outside of flood areas);
- Moving procurement earlier in the process to allow more risk mitigation options and more control over the release of materials;
- Using an A/E firm to develop early designs to support the Study Level/50% estimates;
- Ensuring the scope identifies security, IT/telecom, and cathodic protection requirements;
- Contractor bid package using issued for construction (IFC) drawings instead of issued for bid (IFB) drawings;
- Engaging internal PSE&G engineering for additional civil and electrical drawing reviews;
- Gaining synergies and cost efficiencies by having two A/E firms each execute two of the four projects; also using a staggered execution approach to better balance the work load and allowing more flexibility in planning and mitigation responses; and,
- Bringing the commissioning aspects into the design considerations.

PSE&G submitted Study level estimates for each of the four current Gas M&R projects to its URB for approval in September 2022. The scope description and estimate for each of these projects is provided in **Table 20 – Gas M&R Station Modernization Scope and Study Level Estimates**.

Table 20 – 4kV Station Modernization Scope and Study Level Estimates

Project	Scope	Estimate (Base)
Brooklawn	Replacement of M&R building, regulator runs, headers, station by-pass, relief valves, temporary bypass at full load, instrumentation, Remote Terminal Unit (RTU) equipment, RTU building, Mono Ethylene Glycol (MEG) unit, Scrubber, annubars, backup generator, cathodic protection, and site security features.	$14,600,000
Hamilton	Replacement of M&R building, regulator runs, headers, station by-pass, relief valves, temporary bypass at full load, instrumentation, RTU equipment, RTU building, MEG unit, annubars, Scrubber, heaters, backup generator, cathodic protection, and site security features.	$19,800,000
Hanover	Replacement of M&R building, regulator runs, headers, station by-pass, relief valves, temporary bypass at full load, heaters, instrumentation, RTU equipment, RTU building, MEG unit, gas chromatograph, backup generator, cathodic protection, and site safety features.	$17,400,000
Hillsborough	Replacement of M&R building, regulator runs, headers, station by-pass, relief valves, temporary by-pass at full load, instrumentation, RTU equipment, annubars, gas chromatograph, backup generator, cathodic protection, and security features.	$12,800,000
Placeholder/R&C	R&C for the subprogram	$22,600,000

While **Table 20** above shows the current estimate for each of the Gas M&R projects, the actual costs incurred through the end of 2022 along with the current forecasts for each of the projects is shown in **Table 21 – Gas M&R Station Modernization Cost Status as of December 31, 2022**.

Table 21 – Gas M&R Station Modernization Cost Status as of December 31, 2022

Project	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Budget*
Brooklawn	$0	$290,951	$290,951	$14,600,000	$14,600,000
Hamilton	$0	$209,295	$209,295	$19,800,000	$19,800,000
Hanover	$0	$189,683	$189,683	$17,378,897	$17,400,000
Hillsborough	$0	$206,528	$206,528	$12,777,698	$12,800,000
R&C/Placeholder	-	-	-	-	$22,600,000
Total	**$0**	**$896,456**	**$896,456**	**$64,556,595**	**$87,200,000**
% of Actuals to Forecast & Budget				**1%**	**1%**
**-Includes $69.8 million under the IAP Rate Mechanism and $17.4 million under Stipulated Base.*					

As shown in **Table 21**, as of the end of 2022 the Gas M&R Station Modernization forecast was approximately $22.6 million under budget, which reflects the R&C balance (which also effectively is a placeholder for potentially adding additional projects to the subprogram, as provided by the Stipulation should the initial four projects be completed under budget).

Conclusions

- Through the end of 2022, only preliminary work has commenced on the Gas M&R Station Modernization subprogram. However, PSE&G's planning for this work has appropriately considered the experience from similar work carried out under the Energy Strong 2 Program.

D. Electric Stipulated Base

"The Company shall spend a total of $160 million on certain capital projects during the Program term that will not be recovered through the IAP Rate Mechanism… Of that $160 million, $142.60 million will be spent at the Company's discretion toward the Electric Outside Plant and/or Substation Modernization Subprograms…as well as the Buried Underground Distribution Cable Replacement Project, and the Open Wire Secondary Upgrade Project as proposed in the Company's filing." (IAP Stipulation)

As indicated above in the except from the Stipulation, the Electric Stipulated Base component of the IAP involves investments of up to $142.6 million towards additional projects under the Electric Outside Plant or Substation Modernization subprograms, and/or towards BUD Cable Replacement or Open Wire Secondary Upgrade projects that were part of PSE&G's IAP filing but not included in the accelerated recovery portion of the approved Program. As the BUD Cable Replacement and Open Wire Secondary Upgrade projects consist of work similar and related to the other Electric Outside Plant projects, PSE&G has included these projects within its Electric Outside Plant PEP discussed in **Section III.A.** above.

Within **Section II**, the PSE&G planned allocation of the Electric Stipulated Base funding as approved by its URB is shown, which has also been summarized below in **Table 22 – Electric Stipulated Base Costs as of December 31, 2022**, which shows the approved funding levels for the Electric Stipulated Base funds and current spend by project (note that for the projects with IAP Rate Mechanism funding, those funds will be expended before costs are incurred against the Electric Stipulated Base funding).

Table 22 – Electric Stipulated Base Costs as of December 31, 2022

Project	Actual Costs*	Electric Stipulated Base	% of Actuals to Stipulated Base Budget
CUG Cable Replacement	$0	$15,000,000	0%
Voltage Optimization	$0	$24,600,000	0%
4kV Station Modernization	$0	$15,000,000	0%
BUD Cable Replacement	$793,395	$70,000,000	1%
Open Wire Secondary Upgrades	$9,528,289	$18,000,000	53%
Total	**$10,321,684**	**$142,600,000**	**7%**
**-Includes spend under Stipulated Base only.*			

1. Buried Underground Distribution (BUD) Cable Replacement

The prioritization criteria established by PSE&G for BUD Cable Replacement project selection is based on a calculated ranking using:

- BUD cause codes only;
- Focused on the 10% poorest performing circuits (number of incidents and minutes) for the prior five years (2018-2022);
- 5-year average faults per mile; and
- 5-year average customer minutes interrupted.

As part of the URB funding approval for the IAP (discussed in **Section II**), PSE&G assumed that the BUD Cable Replacement scope would contemplate the replacement of the 1,400 worst performing sections. Since that time, PSE&G re-prioritized the BUD cable target list that now contemplates replacement of 1,916 sections for approximately 110 miles. The prioritization of these sections will be updated by PSE&G on an annual basis to reflect the most recent reliability data, costs per unit, and the work performed to date.

During the fourth quarter of 2022, PSE&G commenced inspections on the circuits and began preliminary engineering ahead of the planned start of construction at the end of the first quarter of 2023.

In **Table 23 – BUD Cable Replacement Costs as of December 31, 2022** the breakdown of costs incurred by Division is provided compared to the current forecasts.

Table 23 – BUD Cable Replacement Costs as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Actual Cost % of Forecast
Central	$3,077	$301,196	$304,273	$21,191,652	1%
Metro	$0	$35,304	$35,304	$3,497,883	1%
Palisades	$11,894	$257,648	$269,542	$10,577,803	3%
Southern	$2,670	$181,606	$184,276	$34,732,662	1%
Total	**$17,641**	**$775,754**	**$793,395**	**$70,000,000**	**1%**

As of the end of 2022, PSE&G is forecasting that the final BUD Cable Replacement projects will go in-service in June 2026.

Conclusions

- The prioritization criteria established by PSE&G for the BUD Cable Replacement projects is an appropriate basis to identify and the select the poorest performing circuits to receive these investments. By having annual updates of the prioritization list, it ensures the targeted investments continue to reflect the intended benefits of the Program.

2. Open Wire Secondary Upgrades

"This project will replace approximately 1,300 secondary locations of existing OWS with new secondary cable and services that have higher capacity and are also more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVa transformers in place, new larger capacity units will be installed." (PSE&G's IAP Filing)

The Stipulation identified that the $142.6 million in Stipulated Base funding identified for the electric scope of the Program could be spent at PSE&G's discretion towards the approved Electric Outside Plant or Substation Modernization projects and/or used towards the BUD Cable Replacement project and the Open Wire Secondary Upgrades project identified in PSE&G's IAP filing. The scope description called out above from PSE&G's IAP filing was based on a proposed budget of $36 million and as indicated in **Table 22**, PSE&G's URB approved a budget of $18 million for the Open Wire Secondary Upgrades project, using a portion of the Stipulated Base funding. Based on this approved budget of $18 million, PSE&G will update its planned scope under this project based on the actual cost data observed in the initial installations and intends to continue to update the installation targets on a quarterly basis.

As PSE&G does not track secondary outages and secondary construction, the prioritization criteria for Open Wire Secondary Upgrades projects uses a preliminary circuit list developed by PSE&G that is based on 4kV circuits with the highest number of 25kVA transformers. This list targeted the circuits with the highest likelihood of open wire secondary construction for the PSE&G and its Divisions to perform field inspections and identify where open wire exists on these circuits. Additionally, PSE&G is using apprentice line workers for this project that provides the dual benefit of additional training through real-world experience while delivering the execution benefits.

For the circuits completed as of the end of 2022, the associated footage and estimate and actual costs are provided in **Table 24 – Open Wire Secondary Upgrades Completed Circuits as of December 31, 2022**.

Table 24 – Open Wire Secondary Upgrades Completed Circuits as of December 31, 2022

Circuit	Footage	Estimate	Actuals
CHA-4001	6,000	$81,871	$58,291
CHS-4006	10,173	$390,000	$433,814
CRA-4001	850	$46,977	$57,058
CRA-4003	7,750	$659,396	$246,627
DUM-4003	700	$64,556	$-
DUM-4004	700	$28,457	$611,731
DUM-4005	500	$76,303	$2,071
DUM-4007	12,300	$677,886	$972,530
EWI-4006	7,750	$320,000	$1,471,199
GRE-4003	11,410	$3,998	$4,506
GRE-4007	2,000	$62,318	$22,877
KEA-4001	2,000	$135,470	$122,905

Circuit	Footage	Estimate	Actuals
KEA-4008	2,000	$138,513	$123,019
TEA-4003	3,150	$251,253	$7,276
TEA-4006	4,000	$115,883	$114,969
TOT-4001 & TOT-4003	4550+1750	$581,007	$283,061
UNC-4012	1,500	$38,810	$128,831
WAR-4002	1,500	$193,034	$2,030
WOR-8018	2,000	$82,217	$100,297
Total	**82,583**	**$3,947,950**	**$4,763,092**

In **Figure 6 – Open Wire Secondary Updates Example** below, photos showing the existing open wire secondary and the updated secondary wire installed through IAP efforts are shown.

Figure 6 – Open Wire Secondary Updates Example

In **Table 25 – Open Wire Secondary Upgrades Cost Status as of December 31, 2022** the overall costs incurred by Division is provided.

Table 25 – Open Wire Secondary Upgrades Cost Status as of December 31, 2022

Division	Q3 Actual Cost	Q4 Actual Cost	Total Actual Costs	Total Forecast	Total Budget
Central	$49,797	$850,016	$899,813	$3,052,956	$18,000,000
Metro	$13,588	$2,607,519	$2,621,107	$4,688,487	
Palisades	$95,688	$3,439,228	$3,534,916	$5,757,325	
Southern	$16,718	$2,455,736	$2,472,454	$4,498,875	
Total	**$175,791**	**$9,352,498**	**$9,528,289**	**$17,997,643**	**$18,000,000**
% of Actuals to Forecast & Budget				**53%**	**53%**

As of the end of 2022, PSE&G is forecasting that the final Open Wire Secondary Upgrades projects will go in-service in December 2023.

Conclusions

- The prioritization criteria for Open Wire Secondary Upgrades project selection is based on a preliminary list of the 4kV circuits with highest number of 25kVA transformers, which have the highest likelihood of open wire secondary construction. Using this list, PSE&G and its Divisions will perform field inspections and identify where open wire secondary exists on these circuits. As PSE&G does not specifically track secondary outages and secondary construction, the IM finds this to be an appropriate basis to identify projects to receive investments.
- PSE&G's use of apprentice line workers for this project provides benefits of additional training through real-world experience while delivering the execution benefits.

PSE&G
Infrastructure Advancement Program

Independent Monitor

July-December 2022

Final Report

Appendix A – Draft Report Comments and Responses

DECEMBER 20, 2023

PEGASUS GLOBAL HOLDINGS, INC.®

Questions & Comments Formally Submitted on the IM 2022 Second Quarter Report

ID #	Question/Comment	IM Response	Report Changes
S-1	Please provide an update on the Company's efforts to obtain federal funding for any IAP projects.	PSE&G indicated to the IM that it has explored applying for federal grants under the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021) but has not applied at this time because PSE&G has not located any such grant that applies to the investments for which the Company seeks rate recovery in this matter.	No change
S-2	**Reference PSE&G IAP July-December 2022 Draft Report, Page 2, Table 1 - IAP Overall Cost Summary as of December 31, 2022** Regarding the forecasted spending within Electric Stipulated Base ($127,597,640), please explain why this total is less than the required Electric Stipulated Base spending of $142.60 million (See PSE&G IAP Stipulation, Paragraph 11).	PSE&G's Electric Stipulated Base forecasted spend as of December 2022 includes forecasted spend for each of the Electric Outside Plant projects that comprise the Electric Stipulated Base spend (CUG Cable Replacement, Voltage Optimization, BUD Cable Replacement, and Open Wire Secondary Upgrades). PSE&G's URB approved $15.0 million of the $142.6 million in Electric Stipulated Base funding towards the 4kV Station Modernization projects. Thus, the approximate $15.0 million variance between the forecast for the Electric Stipulated Base and the Stipulation approved Electric Stipulated Base funding is attributed to the 4kV Station Modernization projects currently being forecasted under budget, which itself is reflective of these projects being in the early stages of planning and development as of the end of 2022.	**Section I**
S-3	**Reference PSE&G IAP July-December 2022 Draft Report, Page 6**	When the 4kV Station Modernization project estimates were updated, the Base estimate for each project decreased from a collective $114.8 million to $108.0 million. This $6.8 million decrease in the Base	No change

ID #	Question/Comment	IM Response	Report Changes
	Refer to the statement "The individual projects that comprise the 4kV Station Modernization subprogram have their estimates provided in Section III.B.2., however, in summary, the five substations approved by the Stipulation for inclusion in the subprogram have Study level estimates that total $108.0 million as the Base estimate, with $64.2 million currently assigned as R&C." Please discuss the need for such a large amount of risk and contingency (approximately 60%) and explain why the risk and contingency increased from original estimates (50%).	estimate total was added to the R&C/placeholder balance and maintained the overall funding level at $172.2 million (which includes $15.0 million from Stipulated Base).	
S-4	**Reference PSE&G IAP July-December 2022 Draft Report, Page 12** Regarding the circuit within the Spacer Hardware Upgrade subprogram for which work was completed by December 2022 (SPF 8022), please provide the budgeted cost, final cost, and total mileage associated with the project.	The estimated cost of the Spacer Harder Upgrade work on circuit SPF 8022 was approximately $683,612, while actual costs were approximately $629,063. The scope of this project included 3.71 miles of circuit upgrades.	**Section III.A.3.**
S-5	**Reference PSE&G IAP July-December 2022 Draft Report, Page 12** Regarding the circuit within the Lashed Cable Replacement subprogram for which work was completed by December 2022 (DUM 4007): a. Please provide the budgeted cost, final cost, and total mileage associated with the project. b. Please explain the Company's rationale for conducting this project given that the circuit's five (5)-year Benchmark SAIDI (0.00743) does not seem to indicate that there are reliability issues present. c. Please explain why the Company did not originally target this circuit for lashed cable replacement in the IAP petition (See PSE&G IAP Petition, Attachment 2, Schedule EFG-IAP-7).	The DUM 4007 circuit under the Lashed Cable Replacement subprogram had an estimated cost of $301,261 and actual costs of approximately $972,530. The IAP filing listed only five circuits representing 14 total miles and was based on the entire circuit mileage that includes sections lashed cable is not needed or required. PSE&G since updated the circuit list to reflect only the lashed cable construction in lieu of the entire circuit mileage. The prioritization is still using lashed cable outage cause codes only and uses updated cost-benefit criteria. As part of the prioritization, all circuits within a station are grouped to determine the combined circuit cost-benefit criteria. This methodology led to the inclusion of DUM 4007, which is one of three circuits related to the Dumont station (DUM 4004 and DUM 4005 are the other two).	**Section II.C.2.** and **Section III.A.2.**

ID #	Question/Comment	IM Response	Report Changes
S-6	**Reference PSE&G IAP July-December 2022 Draft Report, Page 12** Regarding the three (3) circuits within the Conventional Underground Cable Replacement subprogram for which work was completed by December 2022 (RFL 8012, FMT 8014, and FMT 8025): a. Please provide the budgeted cost, final cost, approximate age of previous cable, and total feet of cable replaced for each circuit. b. Please explain the Company's rationale for conducting these projects given that the circuits' five (5)-year Benchmark SAIDI values do not seem to indicate that there are reliability issues present. c. Please explain why these circuits were not originally targeted for underground cable replacement in the Company's petition (See PSE&G IAP Petition, Attachment 2, Schedule EFG-IAP-9).	Regarding the CUG projects for circuits RFL 8012, FMT 8014, and FMT 8025: a. The age of the cable replaced was approximately 48 years old based on PSE&Gs estimates. The budgeted and actual costs (as of Dec. 2022) are provided below: b. FMT 8014 and FMT 8025 were previously labeled as circuits SWT 8001 and SWT 8002 prior to a circuit conversion. This conversion resulted in the previous SAIDI data for SWT 8001 and SWT 8002 not being incorporated into FMT 8014 and FMT 8025, which is now corrected within **Section II.C.2.** For RFL 8012, its 5-year SAIDI was 0.10116, notably higher than the current period performance of 0.00612. c. These circuits were selected based on a updated reliability ranking performed by PSE&G in 2022.	**Section II.C.2.**
S-7	**Reference PSE&G IAP July-December 2022 Draft Report, Page 15, Footnote 1** Refer to the statement "in early 2023, PSE&G made the decision to transition the Open Wire to Spacer work initially planned for the Energy Strong 2 Program to the IAP due to limited funding available in the Electric Stipulated Base portion of the Energy Strong 2 Program." a. Please identify the circuits that will be transitioned from the Energy Strong 2 program to the IAP. b. Please provide the five (5)-year (2018-2022) SAIFI and CAIDI and five (5)-year (2018-2022) tree-related SAIFI and CAIDI for the circuits that will be transitioned from the Energy Strong 2 program to the IAP.	PSE&G has confirmed with the IM that the circuit priority list for Spacer Cable Conversion/Open Wire to Spacer investments planned for the Energy Strong 2 Program (under Electric Stipulated Base, Outside Plant-Higher Design Standard (OP-HDS)) is the same initial list utilized for the projects now planned for execution under the IAP, with the list updated annually to reflect the most recent reliability data and to update the circuit prioritization. Given that PSE&G has applied a common approach to the circuit identification and prioritization, including refreshing the data annually to ensure the list remains tied to current reliability data, the IM finds it reasonable for PSE&G to use the same circuit priority list for the Spacer Cable Conversion investments that was	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
	c. Please discuss if the Independent Monitor believes that the historical reliability of the Energy Strong 2 circuits warrants prioritization over the originally planned IAP circuits.	originally developed for the OP-HDS work within the Energy Strong 2 Program. The 5-year average CAIDI and SAIFI of the circuits identified for Spacer Cable Conversion projects, including for both non-Major Event and for tree-related events, has been added to the IM report within **Table 7 – Spacer Cable Conversion Circuit Metrics**.	
S-8	**Reference PSE&G IAP July-December 2022 Draft Report, Pages 15-16, Lashed Cable Replacement** Please identify the 17 circuits currently included in the Lashed Cable Replacement subprogram and provide the following information for each circuit: a. Total miles to be replaced b. Budgeted cost c. Five (5)-year (2018-2022) SAIFI and CAIDI	The draft IM report incorrectly identified 17 engineering packages as being completed for the Lashed Cable Replacement projects, the correct total as of the end of 2022 was 15 packages. The estimated miles, budgeted cost, and 5-year SAIFI and CAIDI metrics for these 15 circuits have been added to the report within **Table 9 – Lashed Cable Replacement Project Detail**.	**Section III.A.2.**
S-9	**Reference PSE&G IAP July-December 2022 Draft Report, Pages 15-16, Lashed Cable Replacement** Please indicate if any circuits originally planned within the Lashed Cable Replacement subprogram (OAK 4008, ORA 4001, NRP 4010, MCL 4007, and RSL 4007) have been removed from the IAP. (See PSE&G IAP Petition, Attachment 2, Schedule EFG-IAP-7). If so, please discuss if the Independent Monitor believes that this decision was reasonable.	Of those five circuits identified for Lashed Cable Replacement investments within Schedule EFG-IAP-7 of the IAP filing, two have been removed from the IAP (OAK 4008 and MCL 4007) as OAK 4008 was improved by a non-IAP project and based on current cost forecasts, it was unlikely that MCL 4007 would be completed with the available funding based on its priority on the list. Additionally, PSE&G has updated its circuit list for the Lashed Cable Replacement projects to reflect both the investments made outside of the IAP and to update the circuit mileage from the full circuit length as was shown in the IAP filing (under Schedule EFG-IAP-7) to the portion of the circuit with lashed cable currently installed. As of August 2023, PSE&G had identified a total of 39 circuits comprised of approximately 8.3	**Section III.A.2.**

ID #	Question/Comment	IM Response	Report Changes
		miles of lashed cable to receive investments through the IAP.	
S-10	**Reference PSE&G IAP July-December 2022 Draft Report, Page 17, Spacer Hardware Upgrades** Refer to the statement "Execution of this work is being performed by a contractor that was awarded through a competitive bid process." Please discuss the bids received for the spacer hardware upgrades and indicate if the lowest bid was selected.	The bid process for the Spacer Hardware Upgrades work followed standard PSE&G procurement processes and included bids received from five contractors. PSE&G's bid evaluation considered technical considerations, such as bid package completeness, technical exceptions, and safety and experience, and commercial considerations, namely pricing. The selected contractor had the third lowest evaluated price, though other lower price bidders were removed from consideration as they were being considered for award for PSE&G's Defective Pole Replacement Program. PSE&G's contract strategy for these scopes was to award this IAP work and the Defective Pole Replacement Program (which was split into a north territory and south territory scope) to three contractors in order to maintain diversity in its supplier utilization. In addition, the IAP scope is much smaller than the Defective Pole Replacement Program, which will also allow the selected IAP contractor the opportunity to continue to develop and become a more experienced overhead contractor for PSE&G.	**Section III.A.3.**
S-11	**Reference PSE&G IAP July-December 2022 Draft Report, Page 17, Spacer Hardware Upgrades** Regarding the Company's decision to reduce the scope of the Spacer Hardware Upgrades subprogram from 300 circuit miles to 125 circuit miles: a. Please provide additional details explaining why actual costs are significantly higher than originally estimated. b. Please identify all circuits and associated mileage currently included within the subprogram.	Concerning the Spacer Hardware Upgrades: a. The initial scope assumption of 300 circuit miles was revised based on a review of existing field conditions and early project costs, with the higher costs driven by conditions in the field, such as damaged cross arms, missing ground wires, etc. b. The current lists of circuits in the Spacer Hardware Upgrades subprogram has been added to the report within **Section III.A.3.**	**Section III.A.3.**

ID #	Question/Comment	IM Response	Report Changes
	c. Please explain the Company's rationale for prioritizing its circuits based upon the prior year's SAIFI ratings, rather than using a larger sample size that incorporates more than one (1) year of data	c. The original circuit list to receive Spacer Hardware Upgrades reflects the 5-year average SAIFI, with the prior year SAIFI rating providing a further prioritization of that original circuit list.	
S-12	**Reference PSE&G IAP July-December 2022 Draft Report, Page 19, Voltage Optimization** Refer to the statement "PSE&G assumed approximately 1,050 pole tap capacitors and switches will be replaced through the IAP. Based on revised estimates developed since that time, PSE&G updated its assumptions and revised the estimated scope to 504 capacitors." Please provide additional details explaining why actual costs are significantly higher than originally estimated.	The main drivers to the updated cost estimate and resulting reduction in number of planned capacitors for the Program includes current vendor pricing and actual costs per unit observed in similar work (such as recloser installations).	**Section III.A.5.**
S-13	**Reference PSE&G IAP July-December 2022 Draft Report, Pages 20-21, 26kV Station Upgrade** Please indicate if the 40 oil circuit breakers currently included in the 26kV Station Upgrade subprogram are the same as those identified in the IAP petition (PSE&G IAP Petition, Attachment 2, Schedule EFG-IAP-5). If not, please explain any adjustments to the originally planned subprogram.	The IAP petition identified 40 breakers at 14 stations to receive 26kV upgrades, after review of station upgrades planned for the next 10 years, PSE&G updated the list, removing three of the original stations and adding seven additional stations, with the total number of OCBs planned for replacement now at 36. The original and current list of stations and breakers is provided in **Table 16 – Original vs. Current 26kV Station Upgrade Projects**.	**Section III.B.1.**
S-14	**Reference PSE&G IAP July-December 2022 Draft Report, Pages 24-27, Gas M&R Station Modernization** Please discuss how PSE&G's planning for the Gas M&R Station Modernization subprogram has accounted for the following lessons learned from the Energy Strong II Gas M&R projects (See Energy Strong II Independent Monitor 2022 Q2 Report, Page 45): a. Insufficient investigation in the development of the projects during front-end planning. b. Upfront scope development did not consider design and execution refinement, resulting in deviation from the	PSE&G has identified and incorporated lessons learned from its experience with the Energy Strong 2 Gas M&R subprogram, including the following areas: *a. Insufficient investigation in the development of the projects during front-end planning:* Conducting upfront investigations of the existing conditions as each site, including a buildings hazardous assessment, Geotech soil borings, collecting as-built drawings, and verifying NJDEP regulations. *b. Upfront scope development did not consider design and execution refinement, resulting in deviation*	**Section III.C.**

ID #	Question/Comment	IM Response	Report Changes
	preliminary scope as formal scope lockdown for these projects did not occur. c. Front-end planning activities were not completed, nor were all stage gates met when Study level estimates were developed by the project teams with A/E firm assistance and submitted to the URB.	*from the preliminary scope as formal scope lockdown for these projects did not occur:* Ensuring the scope includes elements such as security, IT/telecom, and cathodic protection requirements and that the design considers commissioning requirements; Using IFC drawings for the contractor bid packages rather than IFB drawings; and engaging internal PSE&G engineering resources for additional civil and electrical drawing reviews. *c. Front-end planning activities were not completed, nor were all stage gates met when Study level estimates were developed by the project teams with A/E firm assistance and submitted to the URB:* Engaging the A/E earlier in the process to develop early designs supporting the Study level/50% estimate and ensuring the upfront investigations noted above were completed.	
S-15	**Reference PSE&G IAP July-December 2022 Draft Report, Page 28, Buried Underground Distribution (BUD) Cable Replacement** For each project within the BUD Cable Replacement subprogram completed through December 2022, please provide the following: a. Circuit ID b. Budgeted cost c. Final cost d. Approximate age of previous cable e. Total feet of cable replaced f. Five (5)-year (2018-2022) SAIFI and CAIDI of each circuit	No BUD projects were completed as of December 2022. As of that time, the work performed primarily involved circuit inspections and preliminary engineering.	No change
S-16	**Reference PSE&G IAP July-December 2022 Draft Report, Page 29, Open Wire Secondary Upgrades**	The estimate and actual costs for the completed circuits as of December 2022 under the Open Wire Secondary Updates projects were added to the main report.	**Section III.D.2.**

ID #	Question/Comment	IM Response	Report Changes
	Regarding the Open Wire Secondary Upgrades projects completed through December 2022, please provide the budgeted cost and final cost of each project.		
RCR-INF-1	In reference to the draft July-December 2022 Independent Monitor report at page 2, please indicate when the Company will complete the detailed forecasts for the Electric Outside Plant subprogram.	The detailed Division forecasts for the Electric Outside Plant subprogram were completed during the first quarter of 2023 (and continue to be updated monthly).	No change
RCR-INF-2	In reference to the draft July-December 2022 Independent Monitor report at page 3, please provide the Company's most recent experiences with long-lead time items relative to delays experienced in the last 18-24 months.	PSE&G has identified certain underground cable and wooden poles has having more constrained availability recently, but has been able to manage its inventory to support project needs.	No change
RCR-INF-3	In reference to the draft July-December 2022 Independent Monitor report at page 3, please indicate if the Company has a target ratio for workforce utilization. If so, please explain how the Company manages the balance between internal Division resources and contractors.	PSE&G does not have targets for use of internal vs. contractor resources on the IAP. The Company generally seeks to execute work with internal resources when feasible, appropriate, and when such resources are available, supplementing with contractor resources as necessary.	**Section I.**
RCR-INF-4	In reference to the draft July-December 2022 Independent Monitor report at page 5, Table 2; please provide an estimated timeframe for the completion of the Stipulated Base spending. If not, please indicate when the Company will have a timetable estimate.	Based on its current forecasts, PSE&G is anticipated the Stipulated Base spend will continue through to the Program end date in June 2026.	No change
RCR-INF-5	In reference to the draft July-December 2022 Independent Monitor report at page 5, please explain why PSEG is not using risk and contingency for just the Outside Plant Program.	Smaller, repetitive type jobs have relatively minor risks compared to the larger, more typical "projects" that have more complex risk profiles. The budgets for the smaller, repetitive type jobs also effectively mean any risks realized with associated cost impacts as the effect of reducing the number of units available to be installed under a fixed budget.	No change
RCR-INF-6	In reference to the draft July-December 2022 Independent Monitor report at page 5, please explain how the experience of the first completed Outside Plant projects has affected the Company's cost and timeline estimates.	PSE&G has monitored the initial experience on the Outside Plant projects to inform the updates to the Program targets (primarily number of circuits and miles) and will continue to update these targets based on the actual costs incurred on the Program. The IM	No change

ID #	Question/Comment	IM Response	Report Changes
		will continue include the targets in its reports as of the current reporting quarter. As of the fourth quarter of 2023, PSE&G has revised its Outside Plant project targets as follows: • Lashed Cable: o Original: 116 circuits; 13 miles o Updated: 39 circuits; 8.3 miles • Spacer Hardware: o Original: 83 circuits; 300 miles o Updated: 39 circuits; 163 miles • CUG: o Original: 30 circuits; 36 miles o Updated: no change • Voltage Optimization: o Original: 1,050 pole top capacitors o Updated: 504 pole top capacitors	
RCR-INF-7	In reference to the draft July-December 2022 Independent Monitor report at page 5, please indicate if the estimated quantity of scope assumptions for the Outside Plant program is a minimum level of completed work. If not, please explain why not.	The estimated quantities listed in the report for the Electric Outside Plant projects reflect PSE&G's initial assumptions based on the funding levels of these projects, if actual costs are lower than anticipated, additional quantities may be installed, likewise, if actual costs are higher than anticipated, it may result in fewer quantities installed than currently assumed.	No change
RCR-INF-8	In reference to the draft July-December 2022 Independent Monitor report at page 9, please explain the split between internal and contract labor for the Spacer Hardware and Open Wire Secondary subprogram.	The Spacer Hardware projects are being executed primarily by contractors (98%), while the Open Wire Secondary projects are split roughly 50%/50% between contractor and internal resources.	No change
RCR-INF-9	In reference to the draft July-December 2022 Independent Monitor report at page 12, please explain why FMT 8014 has not data.	FMT 8014 and FMT 8025 were previously labeled as circuits SWT 8001 and SWT 8002 prior to a circuit conversion. This conversion resulted in the previous SAIDI data for SWT 8001 and SWT 8002 not being incorporated into FMT 8014 and FMT 8025, which is now corrected within **Section II.C.2.**	**Section II.C.2.**

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-10	In reference to the draft July-December 2022 Independent Monitor report at page 12, please explain why there is no 5-yr benchmark SAIDI data for FMT 8025.	FMT 8014 and FMT 8025 were previously labeled as circuits SWT 8001 and SWT 8002 prior to a circuit conversion. This conversion resulted in the previous SAIDI data for SWT 8001 and SWT 8002 not being incorporated into FMT 8014 and FMT 8025, which is now corrected within **Section II.C.2.**	**Section II.C.2.**
RCR-INF-11	In reference to the draft July-December 2022 Independent Monitor report at page 13, please provide a copy of the Company's current program execution plan.	As this is a PSE&G document, the IM is not in a position to transmit it to other parties.	No change
RCR-INF-12	In reference to the draft July-December 2022 Independent Monitor report at page 13, please indicate what the Company's anticipate frequency for updating the full program execution plan is given that elements of the plan are updated monthly.	PSE&G updates its execution plans on an annual basis, which is common industry practice based on the IM's experience. For the project elements that are updated monthly (e.g. cost and schedule data), the PEP provides the direction and processes for updating and reviewing that type of project data, but these processes are generally consistent throughout the execution of the Program.	No change
RCR-INF-13	In reference to the draft July-December 2022 Independent Monitor report at page 15, please indicate if the Company is moving stipulated base work from the Energy Strong 2 program into the Infrastructure Advancement Program. If so, please explain the amount and what other stipulated base work projects will offset the proposed reallocation.	The Spacer Cable Conversion/Open Wire to Spacer projects have a common scope and same selection and prioritization criteria to the Outside Plant-Higher Design Standards (OP-HDS) work planned as part of the ES 2 Electric Stipulated Base work. Based on the available funding in the ES 2 Program, PSE&G transitioned this work to the IAP in early 2023. However, in the fourth quarter of 2023, PSE&G determined funding was available for some of the identified circuits to be included in the ES 2 Program, with six selected.	**Section III.A.1.**
RCR-INF-14	In reference to the draft July-December 2022 Independent Monitor report at page 15, please indicate the approximate number of circuits that are on the preliminary lists for the spacer cable conversion program.	At this time, PSE&G has identified 28 circuits planned to receive upgrades through the Spacer Cable Conversion projects. A list of these circuits and their related performance metrics has been added to the report as **Table 7 – Spacer Cable Conversion Circuit Metrics**.	**Section III.A.1.**

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-15	In reference to the draft July-December 2022 Independent Monitor report at page 15, please explain why the prioritization process for the lashed cable replacement program is based on 7-years, instead of 5-years.	The Lashed Cable Replacement project selection criteria includes the cost-benefit ratio for the prior five years, while the Spacer Cable Conversion project selection criteria includes the cost-benefit ratio for the prior seven years. The Spacer Cable Conversion project selection criteria uses seven years due to its overlap with the Energy Strong 2 Program's OP-HDS work. This allows PSE&G to prioritize this common work across two Program using a combined circuit list. After the Energy Strong 2 Program ends at the end of 2023, PSE&G will reprioritize the circuit list using the current five-year reliability data (2019-2023) for the remaining circuits to be executed under the IAP.	**Section III.A.1.**
RCR-INF-16	In reference to the draft July-December 2022 Independent Monitor report at page 16, please explain if there is [a] practical transition point for the lashed cable work if only a portion of the circuit will be upgraded. Please provide some photo examples.	The lashed cable work replaced the portions of the circuit with lashed cable, which is typically from pole-to-pole. A photo example of this work was added to the main report.	**Section III.A.2.**
RCR-INF-17	In reference to the draft July-December 2022 Independent Monitor report at page 17, please explain why there is a drop in estimated miles from 300 to 125 for the proposed work.	The initial scope assumption of 300 circuit miles was revised based on a review of existing field conditions and early project costs, with the higher costs driven by conditions in the field, such as damaged cross arms, missing ground wires, etc. See also the response to **S-11**.	**Section III.A.3.**
RCR-INF-18	In reference to the draft July-December 2022 Independent Monitor report at page 17, please describe the Company's experience with the ongoing work, since approximately 1/3 of the work has been completed by the end of 2022.	The Company has identified variations in field conditions as it has performed the Spacer Hardware Upgrade work, such as damaged cross arms, missing ground wires, or circuits already upgraded. In the locations requiring permits (generally road occupancy permits), PSE&G has found that the permit approval time has typically taken 1-2 months. Later in 2023, PSE&G observed the contractor performing the work	No change

ID #	Question/Comment	IM Response	Report Changes
		was not meeting safety/human performance expectations and early in the fourth quarter of 2023 transitioned to a new contractor. Additionally, the Company is considering using Stipulated Base funds to perform additional Spacer Hardware Upgrade work, the IM will continue to report on the status of this scope as it advances.	
RCR-INF-19	In reference to the draft July-December 2022 Independent Monitor report at page 18, please explain why the Company has only found that actual conditions only require minimal modifications. Does the Company expect to spend less on the program?	The minimal manhole modifications to date simply reflect the actual conditions observed. If actual CUG project costs are lower than previously estimated, PSE&G intends to replace additional poor performing circuits in priority order until the available budgets are fully allocated.	No change
RCR-INF-20	In reference to the draft July-December 2022 Independent Monitor report at page 19, what are the shortages for materials for the conventional underground cable replacement program.	The CUG Cable Replacement projects were identified as having EPR cable as a potential risk given the current availability of this material.	No change
RCR-INF-21	In reference to the draft July-December 2022 Independent Monitor report at page 19, please explain why the Company anticipates a drop in the number of pole [top] capacitors for the voltage optimization program.	The main drivers to the updated cost estimate and resulting reduction in number of planned capacitors for the Program includes current vendor pricing and actual costs per unit observed in similar work (such as recloser installations). See also response to **S-12**.	**Section III.A.5.**
RCR-INF-22	In reference to the draft July-December 2022 Independent Monitor report at page 19, please provide an update on the Company's experience with the LEV 8002 pilot work.	On the Capacitor Bank Upgrade pilot project (LEV 8002), PSE&G encountered challenges with SCADA communication during installation that required the vendor field verify and rework the controller programming to address the calibration expected results for voltage and current capacitor operational status (open/closed). These challenges were resolved and the project was fully tested and commissioned in June 2023.	No change
RCR-INF-23	In reference to the draft July-December 2022 Independent Monitor report at page 23, please provide an update on the five stations.	Efforts through 2023 on the 4kV Station Modernization projects primarily involve ongoing design, permitting, and procurement. In August 2023, civil contingency construction commenced at Totowa.	No change

ID #	Question/Comment	IM Response	Report Changes
RCR-INF-24	In reference to the draft July-December 2022 Independent Monitor report at page 23, please explain if the Company has incorporated the experience from the Energy Strong 2 program into the planning and implementation for the proposed 4kV Modernization work.	The successful implementation of the over-under design has allowed the McLean and Teaneck 4kV Station Modernization projects to proceed under a similar approach, allowing the accommodation of large, modernized equipment at very space-constrained sites. The execution of the contingency scope of the Electric Station Flood Mitigation projects has also informed the strategy and approach to contingency planning for the IAP projects. Other aspects of the Energy Strong 2 experience that have been applied to the IAP include selecting two switchgear vendors and modifying contracting strategies to mitigate supply chain risks.	No change
RCR-INF-25	In reference to the draft July-December 2022 Independent Monitor report at page 23, please indicate if the Company utilized outside engineering for the Plainfield substation work. If so, please indicate how that will impact the proposed work for McLean Blvd. and Teaneck substations.	The Plainfield project in the Energy Strong 2 Program utilized Black and Veatch (B&V) as the A/E, the Mclean and Teaneck projects within IAP are also using B&V.	No change
RCR-INF-26	In reference to the draft July-December 2022 Independent Monitor report at page 25, please provide an update on the status of work at the four stations.	The work on the Gas M&R Station Modernization projects through 2023 focuses primarily on advancing the design, submitting permit applications, and commencing the procurement process.	No change
RCR-INF-27	In reference to the draft July-December 2022 Independent Monitor report at page 28, please explain why there is an increase in the number of circuits for the proposed work.	The increase in the planned number of circuits for the BUD Cable Replacement was the result of PSE&G's annual re-prioritization update, though remains with the same overall budget and forecast.	No change
RCR-INF-28	In reference to the draft July-December 2022 Independent Monitor report at page 29, please explain why there is no prioritization process for the open wire secondary work.	As PSE&G does not track secondary outages and secondary construction, the prioritization criteria for Open Wire Secondary Upgrades projects uses a preliminary circuit list developed by PSE&G that is based on 4kV circuits with the highest number of 25kVA transformers.	No change

<table>
<tr><th>ID #</th><th>Question/Comment</th><th>IM Response</th><th>Report Changes</th></tr>
<tr><td>RCR-INF-29</td><td>In reference to the draft July-December 2022 Independent Monitor report at page 29, please provide representative photos of the open wire secondary work.</td><td>Photos depicting Open Wire Secondary Upgrade work have been added to the main report.</td><td>Section III.D.2.</td></tr>
<tr><td>Rate Counsel 10/2 Letter</td><td>The IM report noted that PSE&G focused on identifying and beginning procurement of long lead items for the 4kV Station Modernization and Gas M&R Station Modernization programs. The Company has a goal of starting construction in 2024 for the 4kV Station Modernization program and 2025 for the Gas M&R Station Modernization program. The Company should keep Board Staff and Rate Counsel apprised of contingencies and delays in the long lead items.</td><td>The IM will continue to monitor and report on the status of long lead items required for the IAP.</td><td>No change</td></tr>
<tr><td>Rate Counsel 10/2 Letter</td><td>The IM noted that the first few circuits for the Electric Outside Plant subprojects will help inform baseline cost estimates for future work. The Company should keep Board Staff and Rate Counsel apprised of how the Company progresses in the development of cost estimates and how that would impact on the extent of currently planned IAP projects as detailed in the table below:
<table>
<tr><th colspan="3">Electric Outside Plant Scope of Work Estimate</th></tr>
<tr><th>Project</th><th>Initial Scope Assumptions</th><th>Current Assumption August 2023</th></tr>
<tr><td>Spacer Cable Conversions</td><td>57 miles</td><td></td></tr>
<tr><td>Lashed Cable Replacement</td><td>14 miles</td><td></td></tr>
<tr><td>Spacer Hardware Upgrades</td><td>300 miles</td><td>125 miles</td></tr>
<tr><td>CUG Cable Replacement</td><td>34 miles</td><td></td></tr>
<tr><td>Voltage Optimization</td><td>1,050 13kV pole top capacitors and switches</td><td></td></tr>
<tr><td>BUD Cable Replacement</td><td>1,400 sections</td><td>1,916</td></tr>
<tr><td>Open Wire Secondary</td><td>600 locations</td><td></td></tr>
</table></td><td>The IM will continue to track and report on the current cost forecasts and resulting scope impacts throughout execution of the IAP.</td><td>No change</td></tr>
</table>

ID #	Question/Comment	IM Response	Report Changes
	This information is important since the Company is not planning to use risk and contingency for the Electric Outside Plant program. This is already evident in the change in the scope assumption for the Spacer Hardware Upgrade from an initial estimate of 300 miles to the current estimate of 125 miles. Conversely, the scope of work for the BUD Cable Replacement program has increased from 1,400 sections to 1,916 sections.		
Rate Counsel 10/2 Letter	The IM noted that PSE&G conducted a pilot installation on circuit LEV 8002 for the Voltage Optimization program. The Company should keep Board Staff and Rate Counsel apprised of the progress of the Voltage Optimization pilot and if there are any synergies with the Company's ongoing smart meter rollout.	PSE&G indicated to the IM it currently does not yet have any existing synergies between the Voltage Optimization work and the Company's ongoing AMI Information System Implementation Project and is not anticipated within the framework of the IAP effort. The AMI's data gathering and modeling effort is in its very early stages. In the future, when PSE&G has sufficient data to take into consideration, PSE&G will seek to use all tools at its disposal, including AMI data, to optimize circuit voltages and better understand the effects of increased EVs and DERs on the PSE&G system.	No change
Rate Counsel 10/2 Letter	The IM noted that PSE&G's 26 kV Substation Modernization program plans to replace approximately 40 oil circuit breakers across its service territory. The Company notes that some identified breakers have and will fail prior to scheduled replacement. The replacement work may not cover the full scope of the proposed work. The Company should keep Board Staff and Rate Counsel apprised of the progress of the replacement work and if there are any opportunities to schedule the full scope of work under an oil circuit breaker failure replacement situation.	The IM will continue to monitor and report on the execution of the 26kV Station Upgrade projects. Opportunities to schedule the full scope of work at the time of a breaker failure replacement may be limited to do the availability of completed engineering and required material.	No change
Rate Counsel 10/2 Letter	The IM noted that PSE&G's 4 kV Station Modernization program includes five substations. The IM noted that the McLean Blvd. and Teaneck stations have a design that is an over/under concept with switchgear installed above the feeder rows due to space constraints. The IM noted that PSE&G's Plainfield station has similar space constraints and incorporated the over/under design concept in Energy Strong 2. Rate Counsel is interested in knowing	The successful implementation of the over-under design has allowed the McLean and Teaneck 4kV Station Modernization projects to proceed under a similar approach, allowing the accommodation of large, modernized equipment at very space constrained sites. The execution of the contingency scope of the Electric Station Flood Mitigation projects has also informed the	No change

ID #	Question/Comment	IM Response	Report Changes
	if there are learning opportunities from the Plainfield station work that would benefit the two substations.	strategy and approach to contingency planning for the IAP projects. Other aspects of the Energy Strong 2 experience that have been applied to the IAP include selecting two switchgear vendors and modifying contracting strategies to mitigate supply chain risks.	
Rate Counsel 10/2 Letter	Under the Electric Stipulated Base program, the IM noted that PSE&G does not track secondary outages and secondary construction. Therefore, the prioritization criteria for Open Wire Secondary Upgrades projects uses the Company's preliminary circuit list based on the number of 25kVA transformers. The IM notes that this list targets circuits with the highest likelihood of open wire secondary construction rather than a prioritization based on outages. As the Company rolls out smart meters, the Company should be able to track outages at a more granular level. This may be part of a retrospective analysis in the future since the Company anticipates completing the Open Wire Secondary program by the end of 2023.	The IM will continue to discuss with PSE&G the data and metrics it has available to support execution of the IAP.	No change
PSEG-1	The reference at page 22 that "the URB submittal also approved $64.2 million as a placeholder/R&C funds for the 4kV Station Modernization scope of work, which includes $15.0 million in Stipulated Base funding and $29.2 million through the IAP Rate Mechanism." Should indicate $49.2 million of the placeholder/R&C funds are under Accelerated Recovery and $15.0 in Stipulated Base.	The split between the funding sources for the 4kV Station Modernization scope has been corrected.	**Section III.A.5.**

Danielle Lopez
Associate Counsel-Regulatory

Law Department
80 Park Plaza, T10, Newark, New Jersey 07102-4194
Tel: 973.430.6479
Email: danielle.lopez@pseg.com

PSEG Services Corporation

August 31, 2023

VIA ELECTRONIC MAIL ONLY
Sherri Golden, Board Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: Infrastructure Advancement Program – Semi Annual Report
January 2023 to June 2023

Dear Secretary Golden:

Enclosed for filing is Public Service Electric and Gas Company's semi-annual Infrastructure Advancement Program report for the period January 2023 to June 2023.

The Infrastructure Advancement Program ("IAP") was addressed by a Board Order dated June 29, 2022 (June 29th Order) in Docket Nos. EO2111211 and GO21112121. That Order adopted a Stipulation pursuant to which PSE&G is operating the program known as IAP.

Paragraph 26 of that Stipulation requires reports on:

- The estimated total quantity of work and the quantity completed to date or, if the project work cannot be quantified with numbers, the major tasks completed, e.g., design phase, material procurement, permit gathering, phases of construction;
- The forecasted and actual IAP costs-to-date for the reporting period and for the Program-to-date; where project work is identified by major category (with the actual variances from forecasted amounts expressed in dollar and percentage terms);
- The estimated IAP Project completion date, and estimated completion dates for each IAP subprogram and the Program as a whole;
- Anticipated changes to IAP Projects, if any;
- Actual capital expenditures made by the utility in the normal course of business on similar project work, identified by major category; and
- Any other performance metric concerning the IAP required by the Board.
- For circuits improved within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, and Spacer Upgrade Project, PSE&G will provide System Average Interruption Duration Index ("SAIDI") results for Major Event11 performance at the circuit level (redacted and confidential unredacted) for circuits affected by a Major Event during the reporting period and at the operating area level and system wide. The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit

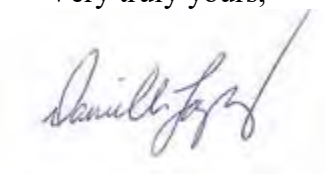
under Major Event conditions for the prior five (5) years from the Program start date. The report will include the SAIDI results at the circuit level for the reporting period.

- For circuits improved upon within the Spacer Cable Conversion Project, Lashed Cable Replacement Project, Spacer Upgrade Project, and Conventional Underground Cable Replacement Project, PSE&G will include non-Major Event performance (where a non-Major Event excludes all "Major Events" as defined at N.J.A.C. 14:5-1.2) including circuit designation (information to be provided redacted and confidential unredacted), that reflects non-Major Event conditions for the reporting period. In addition to SAIDI, the Company will report non-Major Event data for Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI"). The SAIDI results will be reported and measured against a baseline that reflects performance for each circuit under non-Major Event conditions for the prior five (5) years from the Program start date.

The reporting requirements listed in paragraph 26 of the Stipulation are addressed by the enclosed materials.

Please contact the undersigned with any questions or concerns.

Very truly yours,



Danielle Lopez

cc: ***Via Email only***
Brian Lipman
David Wand
Maura Caroselli
Karen Forbes
Stacy Peterson
Malike Cummings
Matko Illic
Caroline Vachier

INFRASTRUCTURE ADVANCEMENT PROGRAM

SEMI-ANNUAL REPORT

TO THE

BOARD OF PUBLIC UTILITIES

Reporting period: January 2023 to June 2023

Table of Contents

Metric 1 – Estimated Quantity of Work....4

ELECTRIC PROGRAM....4
ELECTRIC INSIDE PLANT....4
Electric Life Cycle Stations....4
Electric Stations 26kV Oil Circuit Breakers (OCB) Replacement....6
ELECTRIC OUTSIDE PLANT....7
Electric Lashed Cable Replacement....7
Electric Open Wire to Spacer....7
Electric Spacer Hardware Upgrades....8
Electric Conventional Underground (CUG) Cable Replacement....8
Electric Buried Underground Distribution (BUD) Cable Replacement....9
Electric Capacitor Bank Upgrades....9
Electric Open Wire Secondary Upgrades....10
GAS METERING & REGULATION (M&R) STATIONS....11

Metric 2 – Estimated Program and Subprogram Completion Dates....12

PROGRAM....12
SUBPROGRAMS....12
ELECTRIC INSIDE PLANT....13
Electric Life Cycle Stations....13
Electric Stations 26kV OCB Replacement....13
ELECTRIC OUTSIDE PLANT....13
Electric Lashed Cable Replacement....13
Electric Open Wire to Spacer....13
Electric Spacer Hardware Upgrades....14
Electric Conventional Under Ground (CUG) Cable Replacement....14
Electric Buried Underground Distribution (BUD) Cable Replacement....14
Electric Capacitor Bank Upgrades....14
Electric Open Wire Secondary Upgrades....14
GAS METERING & REGULATION (M&R) STATIONS....15

Metric 3 – Circuit Performance - SAIDI/SAIFI/CAIDI....16

Metric 4 – Semi Annual and Program To-Date Forecast and Actual Costs with Variance 17

ELECTRIC INSIDE PLANT 17
Electric Life Cycle Stations 17
Electric Stations 26kV OCB Replacement.....17
ELECTRIC OUTSIDE PLANT 18
Electric Lashed Cable Replacement 18
Electric Open Wire to Spacer 18
Electric Spacer Hardware Upgrades 19
Electric Conventional Under Ground (CUG) Cable Replacement 20
Electric Buried Underground Distribution (BUD) Cable Replacement.....20
Electric Capacitor Bank Upgrades.....21
Electric Open Wire Secondary Upgrades.....21
GAS METERING & REGULATION (M&R) STATIONS 22
Similar Projects Comparable to IAP Subprograms 23
Detailed Tables for Metric 3 for Semi Annual Report 2023-1 – Non-Major Event Performance .24

Table M3.B.a – Conventional Underground (CUG) Cable Replacement.....24
Table M3.B.b – Spacer Hardware Upgrades 25
Table M3.B.c – Lashed Cable Replacement 26
Table M3.B.d – Open Wire to Spacer.....27

Metric 1 – Estimated Quantity of Work

For each Infrastructure Advancement Subprogram:

A. Estimated quantity of work

i. **For the Entire Subprogram**

ii. **Planned to date (based on forecasted estimates at the beginning of the reporting period)**

B. Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. design phase, material procurement, permit gathering, phases of construction;

NOTE: This quarterly report covers Program to date performance up to the 1st half of 2023 period - January 1, 2023 through June 30, 2023. At the end of the period, all subprograms/projects have advanced through varying stages of planning authorization and execution and completion. Where applicable, forecasted and actual units of work and/or major tasks completed are provided.

ELECTRIC PROGRAM

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the modernization of 4kV switchgear at five (5) electric distribution 69/4kV substations, including replacing and upgrading breakers, disconnects, reactors, regulators, relays, and other infrastructure. The following five (5) substations are included within the project:

- Fortieth Street
- McLean Blvd
- Teaneck
- Tonnelle Ave
- Totowa

ii. **Planned to Date:** Major work planned to the end of June 2023:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- Detailed Engineering Start
- L&P package issued

McLean:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued

Teaneck:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings issued
- L&P package issued

Totowa:

- Major Equipment POs issued
- KDR package approved
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued

B. Quantity of Work Completed to Date:

Fortieth:

- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued
- Detailed Engineering Start
- L&P package issued

McLean:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approval
- Preliminary Vendor Drawings Issued

Teaneck:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Tonnelle:

- A&E contract and PO issued for detailed engineering
- Major Equipment POs issued
- KDR package approved
- Preliminary Vendor Drawings Issued

Totowa:

- Major Equipment POs issued
- KDR package approval
- L&P package issued
- SCD permit issued
- Preliminary Vendor Drawings Issued

Electric Stations 26kV Oil Circuit Breakers (OCB) Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 36 Oil Circuit Breakers.

ii. **Planned to Date:** Major work planned to the end of June 2023:

Replacement of six 26kV Oil Circuit Breakers.

B. Quantity of Work Completed to Date:

Replaced four 26kV Oil Circuit Breakers.

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes replacing approximately 8 miles of existing lashed primary cable construction with spacer cable construction that is designed to a higher and more resilient standard.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Replacement of 1 mile of lashed primary cable with spacer cable.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Replaced 0.79 circuit miles.
- Program to date - Replaced 1.09 circuit miles.

Electric Open Wire to Spacer

A. Estimated Quantity of Work:

i. **Project:** This project will replace aging, 3-phase, open wire construction (cross arm and armless) with PSE&G's current standard, spacer cable type construction. Additionally, replacement work will also require the upgrading of auxiliary equipment as part of the conversion.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- No work currently planned. This program does not begin until 2024.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Replaced 10.21 circuit miles.
- Program to date - Replaced 10.21 circuit miles.

Electric Spacer Hardware Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes 160 miles of existing spacer type construction. This project will replace aging spacer units along existing construction with new hardware that is designed to a higher and more resilient standard. Also, worn, defective, or metallic tangent brackets will be replaced with a newer fiberglass tangent bracket. Messenger ground wire will be installed at every pole if not currently installed.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Completion of 40 circuit miles.

B. Quantity of Work Completed to Date:

- January 2023 to June 2023 – Completed 57 circuit miles.
- Program to Date – Completed 79 circuit miles.

Electric Conventional Underground (CUG) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 34 miles of conventional underground cable.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Civil work to repair crushed conduit.
- Complete all CUG's in Palisades & Central.

B. Quantity of Work Completed to Date:

- January to June 2023 – Replaced 1.81 circuit miles of cable.
- Program to date – Replaced 6.58 circuit miles of cable.

Electric Buried Underground Distribution (BUD) Cable Replacement

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 110 miles of BUD cable.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- No Major Activities Planned.

B. Quantity of Work Completed to Date:

- January to June 2023 – Replaced 0.11 circuit miles of cable.
- Program to date – Replaced 0.11 circuit miles of cable.

Electric Capacitor Bank Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of 479 capacitors. The following stations have been identified for this project:

- Palisades Div. – Penhorn (76)
- Metropolitan Div. – West Caldwell (169)
- Central Div. – Pierson (95)
- Southern Div. – Levittown (139)

ii. **Planned to Date:** Major work planned to the end of June 2023:

- PO for 80 units to be issued by early May 2023.

B. **Quantity of Work Completed to Date:** Major Activities completed by end of June 2023:

- PO issued in April for delivery of 80 units in 2023.
- Completed station/circuit testing for 604 existing capacitors.

Electric Open Wire Secondary Upgrades

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes the replacement of approximately 50 miles over 139 circuits of Open Wire Secondary across the entire PSEG service territory with new secondary cable that have higher capacity and are more resistant to storms and tree contacts. In addition, in areas with lower rated 25kVa transformers in place, new larger 50kVa capacity transformer will be installed.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Planned to complete 16.8 miles through June out of total estimate of 37 miles for the year 2023.

B. Quantity of Work Completed to Date:

2023 construction completion metrics by division:

- Palisades –
  - 24 circuits worked
  - 60,682 feet of wire replaced
- Metropolitan –
  - 47 circuits worked
  - 45,610 feet of wire replaced
- Central –
  - 16 circuits worked
  - 29,819 feet of wire replaced
- Southern –
  - 18 circuits worked
  - 51,123 feet of wire replaced

GAS METERING & REGULATION (M&R) STATIONS

A. Estimated Quantity of Work:

i. **Project:** The estimated quantity of work for this Subprogram includes implementation of life cycle upgrades 4 Gas M&R Stations (Brooklawn, Hamilton, Hanover, and Hillsborough) listed in the Program Stipulation and life cycle upgrades at all 4 M&R Stations as part of the IAP Gas Subprogram.

ii. **Planned to Date:** Major work planned to the end of June 2023:

- Award Detailed Design Engineering to A/E firms for all 4 Stations.
- Start Detailed Design Engineering for all 4 Stations.
- Award material procurement PO to A/E firms (Brooklawn & Hillsborough)
- Finalize Piping & Instrumentation Diagram (P&ID) drawings packages (Brooklawn & Hillsborough)
- Start Site Plan drawings packages (Brooklawn & Hillsborough)

B. Quantity of Work Completed to Date:

- Started Detailed Design Engineering for all 4 stations.
- Completed P&ID drawings packages (Brooklawn & Hillsborough)
- Started KDR drawings package review (Brooklawn & Hillsborough)
- Started Interconnect Agreement with gas pipeline operators (Brooklawn & Hillsborough)
- Completed Site Plan drawings package (Brooklawn)
- Started Site Plan drawings package (Hillsborough)

Metric 2 – Estimated Program and Subprogram Completion Dates

The estimated IAP project completion date, and estimated completion dates for each IAP sub-program and the Program as a whole.

PROGRAM

Program	Subprogram	Forecast In-Service	Timeline for Completion*
IAP	Electric & Gas	Jun-26	Dec-26

SUBPROGRAMS

Program	Subprogram	Forecast In-Service	Timeline for Completion*
Electric	Life Cycle Projects	Sep-25	Mar-26
Electric	26kV Oil Circuit Breaker Replacement	Jun-26	Dec-26
Electric	Lashed Cable	May-26	Nov-26
Electric	Open Wire to Spacer	Dec-25	Jun-26
Electric	Spacer Hardware	Dec-23	Jun-24
Electric	CUG Cable	Jun-26	Dec-26
Electric	Capacitor Bank Upgrades	Jun-26	Dec-26
Electric	Open Wire Secondary Upgrades	Dec-23	Jun-24
Electric	BUD Cable	Jun-26	Dec-26
Gas	M&R Stations	Oct-25	Jul-26

*** Timeline for Completion is defined by the completion date of project closeout report.**

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Tonnelle Ave Substation	Jan-25	Jul-25		
40th Street Substation	Feb-25	Aug-25		
Totowa Substation	Mar-25	Sep-25		
McLean Blvd Substation	Sep-25	Mar-26		
Teaneck Substation	Sep-25	Mar-26		

Electric Stations 26kV OCB Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
26kV OCB Replacement	Jun-26	Dec-26		

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Lashed Cable Replacement	May-26	Nov-26		

Electric Open Wire to Spacer

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire to Spacer	Dec-25	Jun-26		

Electric Spacer Hardware Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Spacer Hardware Upgrades	Dec-23	Jun-24		

Electric Conventional Under Ground (CUG) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
CUG Cable Replace	Jun-26	Dec-26		

Electric Buried Underground Distribution (BUD) Cable Replacement

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Open Wire Secondary Upgrades	Dec-23	Jun-24		

Electric Capacitor Bank Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Capacitor Bank Upgrades	Jun-26	Dec-26		

Electric Open Wire Secondary Upgrades

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
BUD Cable Replacement	Jun-26	Dec-26		

GAS METERING & REGULATION (M&R) STATIONS

Project	Forecast In-Service	Timeline for Completion	Updates	Expected Changes
Brooklawn M&R	Nov-24	Jul-25		
Hillsborough M&R	Nov-24	Jul-25		
Hamilton M&R	Oct-25	Jul-26		
Hanover M&R	Oct-25	Jul-26		

Metric 3 – Circuit Performance - SAIDI/SAIFI/CAIDI

This metric includes data for completed circuits involved in the Major and Non-Major events occurred in the 1st half of 2023, from January 1st, 2023 to June 30th, 2023.

A. Reports included for **Major events** in 1st half of 2023 –

No Major Events occurred in the reporting period.

B. Reports included for **Non-Major Events** in 1st half of 2023 –

M3.B.a Conventional Underground Cable Replacement.
M3.B.b Spacer Hardware Upgrades.
M3.B.c Lashed Cable Replacement.
M3.B.d Open Wire to Spacer.

Detailed tables for this metric are included at the end of this report, page 24 and onwards.

Metric 4 – Semi Annual and Program To-Date Forecast and Actual Costs with Variance

ELECTRIC INSIDE PLANT

Electric Life Cycle Stations

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,837,323	$3,175,314	$337,991	12%		**Total**	$3,422,858	$3,760,849	$337,991	10%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Stations 26kV OCB Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,737,339	$1,534,065	-$1,203,275	-44%		**Total**	$3,344,624	$2,141,350	-$1,203,275	-36%

ELECTRIC OUTSIDE PLANT

Electric Lashed Cable Replacement
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$1,539,599	$1,429,294	-$110,306	-7%		**Total**	$2,831,869	$2,721,563	-$110,306	-4%

Electric Open Wire to Spacer
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$9,265,330	$9,265,330	100%		**Total**	$0	$9,265,330	$9,265,330	100%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Spacer Hardware Upgrades
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$3,193,321	$8,075,955	$4,882,634	153%		**Total**	$8,416,033	$13,298,667	$4,882,634	58%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$294,386	$294,386	100%		**Total**	$0	$294,386	$294,386	100%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Conventional Under Ground (CUG) Cable Replacement

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,371,315	$0	-$2,371,315	-100%		**Total**	$3,733,143	$1,361,827	-$2,371,315	-64%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$2,819,184	$2,819,184	100%		**Total**	$0	$2,819,184	$2,819,184	100%

Electric Buried Underground Distribution (BUD) Cable Replacement

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$7,991,753	$11,207,594	$3,215,842	40%		**Total**	$8,785,148	$12,000,989	$3,215,842	37%

Infrastructure Advancement Program
Semi Annual Report, 2023-1

Electric Capacitor Bank Upgrades
- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$363,852	$372,147	$8,295	2%		**Total**	$459,792	$468,086	$8,295	2%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

Electric Open Wire Secondary Upgrades
- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$4,701,733	$6,494,899	$1,793,166	38%		**Total**	$14,230,022	$16,023,189	$1,793,166	13%

GAS METERING & REGULATION (M&R) STATIONS

- Accelerated Recovery

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$2,005,642	$1,354,705	-$650,936	-32%		**Total**	$2,902,098	$2,251,161	-$650,936	-22%

- Stipulated Base

Semi-Annual Performance (2023-1, January to June) **Program to Date (June, 2023)**

Cost	Forecast*	Actual	Variance ($)	Variance (%)		Cost	Forecast*	Actual	Variance ($)	Variance (%)
Total	$0	$0	$0	0%		**Total**	$0	$0	$0	0%

*Semi Annual forecast is as of January 1st, 2023.

Similar Projects Comparable to IAP Subprograms

Actual capital expenditures made in the normal course of business on similar projects, identified by comparable IAP sub-program:

IAP Investment Category	Description	Applicable IAP Subprograms	Capital Spend on Comparable Non-IAP Subprograms
Hardening & Resilience	Harden infrastructure, thereby making it less susceptible to damage from major storm events, wind and vegetation contact. Strengthen the resiliency of the Company's delivery system.	* Electric Open Wire to Spacer * Electric Lashed Cable * Electric Spacer Hardware * Electric Open Wire Secondary	$ 4,446,037
Life Cycle	Reliability - LC replacements	* Electric Stations LC (4kV) Replacement * 26kV OCB Replacement * Capacitor Bank upgrades * Conventional Underground Cable replace * Buried Underground Cable replace * Gas M&R Station Modernization	$ 32,706,873
Total	**Capital Spend from July 2022 to June 2023**		**$ 37,152,910**

Detailed Tables for Metric 3 for Semi Annual Report 2023-1 – Non-Major Event Performance

Table M3.B.a – Conventional Underground (CUG) Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.
Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place.

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
FMT 8014		0.00001	9.0	0.00011
FMT 8025				
RFL 8012	0.11690	0.00013	50.81	0.00636
LEO 8043	0.02105	0.00019	58.00	0.01075
LUM 8014	0.01924	0.00000	355.00	0.00058
NED 8016	0.06070	0.00002	84.00	0.00126
SPF 8022	0.10116	0.00077	17.00	0.01306
LAF 8011	0.24229	0.00001	9.00	0.00011

Table M3.B.b – Spacer Hardware Upgrades

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
SPF 8022	0.24229			
ALD 8023	0.05707	0.00049	64.54	0.03133
GBK 8021	0.03092	0.00003	65.00	0.00206
RFL 8024	0.10316			
CLF 8022	0.09375	0.00001	119.00	0.00169
COR 8044	0.12235	0.00002	86.00	0.00161
JAC 8032	0.10803	0.00004	104.34	0.00445
KIN 8025	0.07501	0.00056	35.61	0.02008
LAU 8011	0.07228	0.00022	20.71	0.00453
RFL 8035	0.03883			
WEW 8021	0.09623	0.00010	45.64	0.00479

Table M3.B.c – Lashed Cable Replacement

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
DUM 4007	0.00743			
MOG 4003	0.13365			
ORA 4002	0.01804	0.00003	212.13	0.00612

Table M3.B.d – Open Wire to Spacer

This report includes quarterly non-major event performance combining all events only for the circuits which are fully completed.

Blank cell indicates no outage for the circuit.

Note: The 0.00000 signifies there was an outage but the value is beyond 5 decimal place

		Report Period Performance		
Circuit	**5 Year Benchmark SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
ALD 8013	0.02803	0.00027	73.87	0.02000
GRN 4008	0.02731			

Test Year Electric Operations and Maintenance

in $000 **Schedule - PANEL-5(a)**

		Test Year Total June 2023 - May 2024
Distribution Operations	$	52,237
Distribution Maintenance	$	127,615
Total	**$**	**179,852**

Major Categories

Corrective Maintenance	$	61,245
Vegetation Management	$	42,276
Inspections	$	14,208
Buildings & Grounds	$	11,871
Measurement / Meter Expense	$	7,240

Test Year Gas Operations and Maintenance

in $000 **Schedule - PANEL-5(b)**

		Test Year Total June 2023 - May 2024
Distribution Operations	$	97,578
Distribution Maintenance	$	30,247
Gas Transmission	$	4,223
Total	**$**	**132,049**
Major Categories		
Safety	$	54,201
Measurement	$	5,368
Gas Markouts	$	12,183
Inspections and Surveys	$	9,960
Main & Service Maintance	$	14,973

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
CLIFFORD PARDO

VICE-PRESIDENT OF TAX AND ASSISTANT CONTROLLER

December 29, 2023
P-4

TABLE OF CONTENTS

I. INTRODUCTION ..... - 1 -

II. IMPACT OF TCJA AND IRA ..... - 2 -

III. TAX EXPENSE AND ACCUMULATED DEFERRED INCOME TAXES ..... - 6 -

IV. TAX ADJUSTMENT CREDIT ..... - 12 -

V. CONSOLIDATED TAX ADJUSTMENT ..... - 22 -

Direct Testimony
Of
Clifford Pardo
Vice-President of Tax and Assistant Controller
PSEG Services Corporation

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Clifford Pardo. My business address is 80 Park Plaza, Newark, New Jersey.

Q. By whom are you employed and in what capacity?

A. I am employed by PSEG Services Corporation as Vice-President of Tax and Assistant Controller. My professional credentials are attached as Schedule CP-1.

Q. What is the purpose of your testimony?

A. In this proceeding, I am testifying on behalf of Public Service Electric and Gas Company ("PSE&G," "Public Service," or "the Company"). The purpose of my testimony is to present and support tax expense, accumulated deferred income taxes ("ADIT"), modifications to the existing Tax Adjustment Credit ("TAC"), the consolidated tax ratemaking adjustment, and other tax issues arising in this proceeding. Specifically, my testimony is comprised of the following sections:

- Section I provides an introduction;
- Section II summarizes the impacts of the 2017 Tax Cuts and Jobs Act ("TCJA") and 2022 Inflation Reduction Act ("IRA"), and their impacts on this rate proceeding;
- Section III presents current and deferred tax expense and ADIT included in this test period;
- Section IV discusses modifications to the TAC; and

- Section V provides the consolidated tax ratemaking adjustment and presents a computation of that adjustment.

Q. Do you sponsor any schedules as part of your prepared testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direct supervision:

- Schedule CP-1 describes my professional qualifications and business experience;
- Schedule CP-2 details the computation of income tax expense for electric and gas for the test year;
- Schedule CP-3 details the computation of accumulated deferred income taxes for electric and gas for the test year;
- Schedule CP-4 details the computation of the estimated annual net Mixed Service Deduction and the Historic Mixed Service ADIT balance; and
- Confidential Schedule CP-5 details the computation of the CTA.

II. <u>IMPACT OF TCJA AND IRA</u>

A) TCJA

Q. Does TCJA have implications for this proceeding?

A. Yes. On December 22, 2017, the President signed into law a bill entitled "To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018", more commonly known as the "Tax Cuts and Jobs Act" or "TCJA." Below I describe the major provisions of TCJA and discuss their impacts on this proceeding.

Q. Please describe the implications to PSE&G of the reduction in the federal corporate income tax rate.

A. Effective January 1, 2018 the TCJA reduced the federal corporate income tax rate from 35% to 21%. This rate change had a number of implications, including:

- Reducing PSE&G's tax expense after 2017;
- Increasing PSE&G's operating income by lowering tax expense;
- Creating a portion of PSE&G's 2017 ADIT balance in excess of what is needed to offset future tax liabilities (excess deferred income taxes or "EDIT"); and
- Altering the after tax cost of debt as well as the revenue gross-up factor and the interest synchronization computation.

Q. What are deferred income taxes and how do they impact customers?

A. PSE&G, through the ratemaking process, charges customers current and deferred income tax expense. Current tax expense represents the tax expense expected to be paid to the government for that tax year. Deferred tax expense represents a future tax liability that will be paid when related temporary differences between book and taxable income reverse.

Q. Can you provide an example?

A. An example of such a temporary difference is the difference created by accelerated depreciation. In the case of accelerated depreciation, deductible tax depreciation exceeds book depreciation in the early portion of an asset's life, but then in the later portion of that asset's life, book depreciation exceeds tax depreciation. In total, the amount of depreciation is the same; just the timing is different. Deferred taxes spread the tax benefit of depreciation over the book life of the property, so that every dollar of book depreciation charged to customers carries

a tax benefit. This deferred tax also reduces rate base so that customers receive the benefit of the cost-free capital.

Q. How did the TCJA create excess deferred income taxes?

A. Deferred taxes are calculated using the tax rate in effect at the time the deduction is claimed. TCJA was enacted in 2017, and reduced that tax rate from 35% to 21% starting in 2018. Because the tax rate has permanently declined to 21%, when those timing differences reverse, the amount of tax owed will be computed at the new lower 21% rate, not 35%. As a result, a portion of PSE&G's December 31, 2017 ADIT balance was in excess of what is needed to offset future tax liabilities and thus must be returned to customers.

Q. Are there requirements on how the EDIT is returned to customers?

A. Yes, depending on the deduction that caused the ADIT balance. These excess deferred taxes fall into two categories: (1) those restricted by the normalization provisions of the TCJA (sometimes referred to as "protected" EDIT); and (2) those that are not (sometimes referred to as "unprotected" EDIT).

Q. How is the protected EDIT returned to customers?

A. The protected excess deferred taxes must be returned to customers using the Average Rate Assumption Method ("ARAM"). The ARAM provision provides for the reversal of EDIT on a vintage and class basis as the related timing differences reverse, using the weighted average tax rate at which deferred taxes were established.

Q. How is the unprotected EDIT returned to customers?

A. By way of contrast to the protected EDIT, the unprotected excess deferred taxes can be returned to customers over any reasonable period. As approved by the Board on October 29,

2018 at the conclusion of the Company's prior rate case, the Company has been refunding unprotected EDIT over an approximately five-year period through December 31, 2023[1], with a slight remaining balance to be refunded in 2024, in accordance with the IRS Private Letter Ruling ("PLR") discussed below.

Q. How does TCJA address accelerated and "bonus" depreciation?

A. While TCJA provides for 100% depreciation for capital expenditures beginning September 27, 2017, regulated utilities are not eligible for this 100% expensing. Beginning in 2018, only regular Modified Accelerated Cost Recovery System ("MACRS") depreciation may be claimed by regulated utilities.

Q. Does TCJA contain any other changes relevant to this case?

A. No.

B) IRA

Q. Does the Inflation Reduction Act of 2022 impact the current rate proceeding?

A. The IRA enacted a new 15% corporate alternative minimum tax ("CAMT") and made material changes to energy tax credit law. Since enactment, the U.S. Treasury has issued various proposed regulations and Notices that provide interim guidance regarding several provisions of the IRA. The Notices related to the CAMT state that Treasury anticipates issuing additional guidance along with proposed and final regulations. Many aspects of the IRA remain

[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order") at 9-11.

unclear and in need of further guidance; therefore, the impact the IRA will have on PSE&G's financial statements and this proceeding is subject to continued evaluation and the issuance of additional authoritative guidance. The Company may propose an adjustment to the TAC or other mechanism to capture the impact of further U.S. Treasury guidance on the CAMT, if such guidance is applicable to PSE&G.

III. TAX EXPENSE AND ACCUMULATED DEFERRED INCOME TAXES

Q. Have you determined the appropriate income tax expense component of operating income for the filed test period?

A. Yes. I have computed a total income tax expense for the test period of $25 million for electric and a total income tax benefit of ($29) million for gas. This is comprised of a current tax benefit of ($8) million for electric and a current tax expense of $11 million for gas, and a deferred tax expense of $33 million for electric and a deferred tax benefit of $40 million for gas. The details of this determination are shown on Schedule CP-2, which shows current tax expense and significant components of deferred tax expense. I provided this tax expense to Mr. McFadden for inclusion in his Schedule MPM–28. The income tax expense includes a tax benefit for bad debt write offs, which is excluded in a pro forma adjustment in the testimony of Mr. McFadden, and is included in Schedule MPM-53.

Q. Did you prepare a schedule showing the balance of ADIT associated with utility plant?

A. Yes. It can be found at Schedule CP–3. In the schedule, I have broken utility-plant-related ADIT down into the following categories:

- ***Accelerated depreciation and other*** – includes the federal deferred taxes that either arise or reverse through depreciation deductions (including bonus depreciation) allowed pursuant to sections 167 and 168 of the Internal Revenue Code ("IRC").

- ***Safe Harbor Adjusted Repair Expense ("SHARE") deductions*** – includes federal deferred taxes associated with projects that are claimed as deductible repair expenses pursuant to IRC section 162 but are capital assets for financial reporting purposes. This deduction is described in more detail below.
- ***Mixed Service tax deduction*** – includes existing federal deferred taxes associated with projects that historically claimed a tax deduction for Mixed Service costs under IRC 162. This deduction is described in more detail below.
- ***NJ corporate business tax*** – includes all deferred taxes provided for the NJ Corporate Business Tax.

Mr. McFadden has reflected these deferred taxes as a rate base reduction in Schedule MPM–03.

SHARE Deduction

Q. What is a SHARE deduction?

A. The SHARE deduction is an acronym for the repair deductions discussed below.

Q. What are repair deductions?

A. On September 12, 2011, the IRS released Revenue Procedure 2011-43, which was later modified in Revenue Procedure 2014-16, detailing a safe harbor method for determining repair deductions for electric transmission and distribution property. Generally, for book and tax purposes, costs are either capitalized into the depreciable basis of an asset or currently expensed for book purposes and deducted for tax purposes. For tax purposes, costs associated with a unit of property are considered deductible repair expenses and not capitalized unless they are incurred for either a) betterment of the property, b) restoration of the property, or c) to adapt the unit of property to a new or different use as determined under the Revenue Procedure.

Q. How do the repair deduction rules apply?

A. These rules apply to all vintages of property and permit immediate expensing of all costs associated with projects considered a deductible repair expense pursuant to IRC section 162, resulting in a tax reduction in the year incurred, but are capital assets for financial reporting and ratemaking purposes. PSE&G has claimed enhanced repair deductions since 2010 for both its electric and gas distribution operations (referred to as a "SHARE deduction"). SHARE deductions are considered unprotected.

Q. Has the IRS provided additional guidance on the Gas SHARE deductions?

A. Yes. In April 2023, the Treasury released Revenue Procedure 2023-15 associated with determining the repair deduction for gas transmission and distribution property.

The impact, if any, of this Revenue Procedure is in process of being determined and possibly may require additional authoritative guidance. The Company reserves the right to propose an adjustment to the TAC to capture the impact of Revenue Procedure 2023-15 including any further guidance issued.

Q. How is the SHARE deduction returned to customers?

A. The SHARE deduction is returned to customers through the TAC in two ways: 1) amortization of the historic SHARE balance and 2) flow-back of the current net SHARE tax benefit. The historic SHARE was a component of the Company's ADIT in the 2018 base rate case. Per the Stipulation of Settlement approved by the Board in the 2018 Rate Case Order, the balance is being flowed-back to customers over a 10-year period, with one-third of the balance returned in the first five years and the two-thirds remaining balance returned in the remaining

five years.[2] The current SHARE is calculated as the on-going, annual SHARE tax deduction less the book depreciation associated with SHARE deductions multiplied by the federal tax rate. It is contemporaneously flowed back to PSE&G's customers.

Q. Is the SHARE deduction the same each year?

A. No. The SHARE deduction has the potential to significantly vary year-to-year based on the actual plant activity and mix of capital projects placed in service each year that qualifies as repair, which causes volatility in the SHARE deduction.

Mixed Service Deduction

Q. What is a Mixed Service deduction?

A. IRC section 263A governs which costs are capitalizable, deductible, or both, referred to in Treasury Regulation Section 1.263A-1(e)(4)(ii)(C) as "Mixed Service costs." That Treasury regulation defines Mixed Service costs as service costs that are partially allocable to production or resale activities (capitalizable) and partially allocable to nonproduction or non-resale activities (deductible). Mixed Service costs are typically thought of as general and administrative costs.

Q. Can you provide an example of a Mixed Service deduction?

A. A company's personnel department may incur costs to recruit employees engaged in the production of self-constructed assets (capitalizable) as well as costs to recruit employees engaged in nonproduction activities (deductible).

[2] 2018 Rate Case Order at 9.

Q. How does the Mixed Service deduction impact ADIT?

A. Treasury Regulation section 1.263A applies to all vintages of property and permits immediate deduction of all costs associated with projects pursuant to IRC section 162, resulting in a tax deduction in the year incurred, but are capital assets for financial reporting and ratemaking purposes. ADIT results from the timing difference between financial reporting, which is depreciated over the life of the asset, and tax reporting, which is immediately deducted. Mixed Service deductions are unprotected and not subject to the tax normalization rules.

Q. Is there more than one directive on how to calculate the Mixed Service deduction?

A. Yes. The IRS has issued a number of Industry Director Directives ("IDDs") related to the computation of the Mixed Service deduction. Generally, the regulated utility industry follows IDD No. 5 (LMSB 04-0809-033, 2009), which is based on the simplified service cost method.

Q. Are you proposing a change in the regulatory treatment of the Mixed Service deduction in this proceeding?

A. Yes. As described below, the Company proposes to return both the historic and current Mixed Service deduction to customers through the TAC in the same manner as done for the SHARE.

Q. Do you have any workpapers or schedules supporting your current Mixed Service forecast?

A. Yes. See Schedule CP-4 for the calculation.

Deferred vs Flow-thru Accounting

Q. What is deferred tax accounting and how does it differ from flow-thru accounting?

A. Generally Accepted Accounting Principles ("GAAP"), codified as ASC 740, require comprehensive inter-period tax allocation for all temporary differences between book and tax accounting. Simply stated, a temporary difference is an item of income or expense, for which the difference in basis or timing of recognition in income differs between tax purposes and financial reporting purposes. When a temporary difference is reflected in the computation of taxable income in a different period than it is for financial reporting purposes, there is an impact on the timing of taxation, and GAAP requires that a deferred tax expense or benefit be recorded on the income statement to reflect the future reversal of that temporary difference. A deferred tax expense results in an increase in ADIT liabilities on the balance sheet, and the liability reverses as the Company repays the temporary benefit to the government in the form of higher tax payments in the future. This is what I refer to as deferred tax accounting.

Q. Can you describe flow-through accounting?

A. To state it simply, flow-through accounting puts the utility on a tax return basis (cash basis) for tax recovery in the ratemaking process. Tax expense or benefit of the particular item will flow to customers in the year in which the taxes are reflected in the tax return. Deferred tax accounting, in contrast, matches the tax impact of an item of expense or income with the recovery of that item from customers.

Q. Is either the flow-through or deferred tax accounting method required?

A. Neither method is required in setting rates, subject to two exceptions.

First, for ratemaking purposes, when the tax normalization rules apply, deferred tax accounting is required. Normalization rules apply to deductions associated with accelerated depreciation claimed pursuant to IRC sections 167 and 168. The deduction for accelerated depreciation will be forfeited if the normalization rules are violated by flowing back tax depreciation benefits to customers too quickly. The normalization rules do not apply to deductions claimed under any other section of the Code, such as the SHARE and Mixed Service deductions that are claimed under IRC section 162.

The second exception is that N.J.S.A. 48:2-21.34 requires deferred tax accounting in setting utility rates for all temporary differences used in computing New Jersey ("NJ") State income tax. Therefore, no ADIT computed at the NJ rate may be flowed through, and instead, normalization would be required for the NJ State income tax portion of the SHARE and Mixed Service deductions.

IV. TAX ADJUSTMENT CREDIT

Q. Can you please describe the TAC?

A. The prior base rate proceeding established a separate Electric and Gas TAC ("ETAC" and "GTAC") as set forth on Attachment C of the Stipulation of Settlement approved in the 2018 Rate Case Order. The 2018 Rate Case Order approved the following eight components of the TAC:

- A one-time refund of the excess income tax recovery from January - March 2018 was issued during the two-month period November and December 2018 and included interest based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month;[3]

[3] These amounts have been flowed back to customers and has no impact on the current rate proceeding.

- Refund of the protected excess deferred tax balance, which is flowed back to customers under the ARAM or any other method as required by the IRS;
- Refund of the unprotected excess deferred tax balance over an approximately five (5) year period through December 31, 2023, with the annual amortization as shown in Attachment C of the Stipulation;
- Refund of the historic SHARE balance as of October 31, 2018 over a 10 year period, with one-third of the balance returned over the first approximately 5 years through December 31, 2023, and the balance returned over the remaining 5 year period ending December 31, 2028;
- Return on the increase in rate base at the Company's after-tax WACC from the flow-through of rate base related excess deferred taxes (comprised of all protected excess deferred taxes, the historic SHARE, and a portion of the unprotected excess deferred taxes as shown in Attachment C of the Stipulation);
- Payment of interest at the Company's after-tax WACC on the balance of the non-rate base related excess deferred taxes until fully refunded over the approximately 5-year period;
- Flow-through of the estimated current period SHARE deduction, plus or minus true-ups from prior periods, calculated as the actual SHARE tax deduction less all associated SHARE book depreciation, multiplied by the Federal tax rate. Any true ups from prior periods will be flowed back to customers in the next appropriate period. Note, this adjustment is inclusive of expenses that made up the ADR repair allowance deduction previously in base rates such that all repair related flow through will be done through the TAC; and

- A revenue gross-up of the net tax flow-through.

The mechanics of the TAC are discussed in the Direct Testimony of Mr. Steven Swetz. Additionally, Attachment C of the Stipulation of Settlement adopted by the Board in the 2018 Rate Case Order set forth the EDIT and SHARE tax benefit balances to be flowed back to customers monthly for the period Jan 2018 through December 2019 and the annual flow back of the protected and unprotected excess deferred taxes for years 2020 through 2029.

Q. Have the balances of the Protected and Unprotected Excess ADIT changed since the 2018 Rate Case Order?

A. Yes. The balances for the Protected and Unprotected Excess ADIT, which were approved to be refunded in the 2018 Rate Case Order, changed for four reasons:

1) A reclassification between the protected and unprotected balance;

2) An ADIT adjustment as a result of the 2017 federal and state return to accruals ("RTA");

3) The result of the IRS ruling on the Company's PLR requests with regard to a change in accounting method and the treatment of cost of removal expenditures, which is discussed in more detail below; and

4) An IRS audit settlement of tax years prior to 2018.

The first two adjustments were included in the Company's 2019 TAC filing and subsequently adjusted to reflect the immaterial impact of the federal benefit of state taxes that resulted from the 2017 state return to accrual.[4] The IRS guidance on the Company's PLR request was not available at the time of the Company's 2019 TAC filing as it was issued in April 2020. The

[4] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2019 TAC Filing")*, BPU Docket Nos. ER19091302 and GR19091303 (filed September 26, 2019).

Company incorporated the results of the PLR requests into the final approved TAC rates approved by the Board on July 16, 2020. There has been no change to the Company's historic SHARE balance. The Company has settled its 2011 through 2016 tax return audit with the IRS and reflected any changes to the excess deferred taxes as a result of the settlement in the fourth quarter of 2020. These impacts were included in the 2021 TAC filing.[5]

Q. Do the first two adjustments (reclassification and 2017 RTA) approved in the 2019 TAC filing affect the current filing?

A. Yes. While the adjustments to the balances occurred in 2018, the relative amortization related to these adjustments are being amortized through 2023.

Q. Please explain what are the PLR reclassifications between protected and unprotected deferred income taxes?

A. In compliance with the Company's Base Rate Case Order, PSE&G sought a PLR from the IRS that would give guidance as to whether excess deferred income tax associated with accounting changes to repair deductions and mixed service costs are protected in nature and subject to normalization rules. In addition, PSE&G also required a PLR from the IRS regarding its post-1981 cost or removal and whether amounts were subject to normalization rules and if it is to be treated as a separate temporary difference or part of the overall depreciation temporary difference.

Q. Did PSE&G obtain those private letter rulings?

A. Yes. In April 2020, the IRS issued a ruling to PSE&G that held both the deficient deferred taxes related to COR and the excess deferred taxes associated with accounting method

[5] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2021 TAC Filing")*, BPU Docket Nos. ER21101201 & GR21101202 (filed October 29, 2021) at Attachment 1 at 10.

changes related to repair deductions and the capitalization of mixed service costs are unprotected and not subject to the tax normalization rules.

Q. What excess amounts will be amortized pursuant to those PLRs?

A. Pursuant to the guidance in the PLR, PSE&G is flowing back $75 million in total net pre-tax credits to customers. Of that amount, approximately $41 million and $34 million in excess deferred income taxes will be amortized to electric and gas customers, respectfully, through 2024.

Q. Are these amounts currently being amortized back to customers?

A. Yes. On July 16, 2020, the Board approved PSE&G's Updated 2019 TAC filing including the reclassification pursuant to the IRS guidance that these deficient deferred taxes related to COR and the excess deferred taxes are not subject to the tax normalization rules. As such, these amounts have been reclassified and are being amortized through the TAC effective July 16, 2020, as approved by the Board.

Q. What are the benefits associated with the TAC?

A. There are several benefits associated with the TAC:

- Utilizing the TAC allows for an uneven method of amortization, which the Company could not do in a traditional base rate amortization without an annual base rate case.
- It provides a mechanism to stop the amortization of historical ADIT once the repair-related ADIT is fully returned to customers, to avoid possible IRS normalization violations.
    - If the Company were to over-amortize the SHARE-deduction-related ADIT balance, the excess amortization arguably would come from the depreciation-

related ADIT, which is protected by the normalization rules. Reversing that deferred tax would result in a normalization violation and the possibility of significant penalties. Use of the TAC eliminates that risk.

- The TAC provides a mechanism that will permit the recovery of IRS audit adjustments, changes, or subsequent clarifications to tax law, or other major tax changes, if any.
    - For example, while the IRS has not challenged the Company's SHARE deductions, tax deductions of this magnitude are routinely scrutinized. Given the size of these deductions and the IRS's policy of auditing multiple years at a time, a final disallowance could be material. Because the tax benefit of any deductions will have already been passed to customers, any IRS disallowance and interest thereon would need to be recovered from customers. The TAC will provide the mechanism to ensure timely recovery.

Q. What is the status of the Excess Deferred Tax balance to be flowed back through the TAC?

A. The reduction in the federal tax rate generated a total of $1 billion of excess deferred taxes. Through the end of 2022, the balance remaining of protected EDIT to be flowed back to customers is approximately $882 million and unprotected EDIT is approximately $203 million. For the test period, the flow back to customers is included in this filing.

Q. Are there any adjustments to the TAC as originally approved in the 2018 rate case?

A. Yes. PSE&G proposes the following adjustments, which are described in more detail later in my testimony:

1) In addition to continuing to flow back the benefit of the historic SHARE deduction, the Company proposes to flow back to customers the net federal tax benefit associated with the historical Mixed Service ADIT balance over approximately five years.

2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case; and

3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of EDIT and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery proceeding.[6] In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology.

I discuss each proposed change below.

1) Historic Mixed Service

Q. Why are you proposing to flow back the historic Mixed Service deduction through the TAC?

A. The historic Mixed Service deduction is an unprotected deferred tax liability that can be flowed back to customers. This is similar to the current mechanism to flow back the historic SHARE to customers with the exception that it would be over an approximate three-year period instead of 10 years as approved in the last rate case for the historic SHARE. The historic Mixed

[6] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit ("2023 TAC Filing")*, BPU Docket Nos. ER23090634 and GR23090635 (filed September 1, 2023) (the "2023 TAC Filing").

Service balance is part of ADIT and reducing the Company's rate base. As the tax benefit is flowed back to customers, the ADIT balance declines and the Company's rate base increases. In the same manner as approved for the historic SHARE, the Company can refund this tax benefit to customers on an accelerated basis and earn a return on the increased rate base as a result of the refunds. The TAC allows for the accelerated refund of the Mixed Service net tax benefit while earning its allowed return as its rate base increases. The projected Mixed Service historic ADIT balance as of August 31, 2024 is approximately $366 million, and grossed up to revenues would represent a benefit to customers of $509 million. See Schedule CP-4 for the historic Mixed Service deduction that the Company proposes to be flowed through to customers through the TAC.

2) Annual SHARE and Mixed Service Deduction

Q. Are you proposing to flow back the annual Mixed Service deduction to customers as well?

A. Yes. As described below, the Company proposes that a fixed annual flow back amount be refunded to customers for both the annual SHARE and Mixed Service deductions.

Q. What is the annual Mixed Service and SHARE flow back?

A. The annual SHARE flow back is the annual Federal repair tax deduction less the associated book depreciation multiplied by the federal tax rate. Likewise, the annual Mixed Service flow back is the annual federal Mixed Service tax deduction less the associated book depreciation multiplied by the federal tax rate.

Q. Can you please discuss the proposal to limit the flow-back of the annual net SHARE and Mixed Service deductions?

A. To ensure that PSE&G customers receive the full benefit of these deductions while minimizing fluctuations in Distribution Customers' bills, the Company proposes to flow back a fixed annual benefit of $38 million and $18 million related to the annual SHARE and Mixed Service deduction, respectively, or a combined impact of $56 million. The actual SHARE and Mixed Service deductions will continue to be calculated and tracked annually. To the extent the actual benefit is higher than the proposed flow back amount, the excess would be added to the ADIT balance and flowed back to customers in a subsequent rate case.

Q. What is the benefit of this approach to limit the flow back amounts?

A. A fixed flow back amount will reduce the rate volatility and revenue requirement swings currently occurring in the existing TAC. The Current SHARE fluctuates annually and has seen significant swings, typically recorded in December. In addition, deferring the difference between the actual and proposed flow back amount can increase ADIT and provide an additional unprotected balance to be refunded to customers in a future rate case.

Q. Can you provide a simple example of how the deferral will work?

A. Yes. Assume this proposal is accepted and allows for a net SHARE deduction of $100 be flowed back to customers. However, the actual benefit is $150. The $50 additional benefit would be added to the existing ADIT balance, reduce rate-base, and be flowed back to customers in a subsequent rate case.

3) Monthly Amortization Pattern

Q. Can you please describe why the monthly amortization pattern of EDIT and SHARE flowback has changed and the impact to the return calculation?

A. As described in the Company's 2023 TAC Filing, the Company has changed the monthly amortization pattern to reflect the seasonality of pre-tax income. Historically, approximately 33% of the Company's revenue is generated in the first quarter each year. However, the tax benefits from flowing back the EDIT and SHARE were amortized on a straight-line basis, which caused a monthly mismatch. As a result, in 2023 the Company changed the monthly amortization of the EDIT and SHARE flowback to follow the seasonal pattern as the Company generates pre-tax income. The full-year total to be flowed to customers is not impacted. For the impact to the return calculation, see Schedule SS-ETAC-1E for electric and Schedule SS-GTAC-1G for gas in the Direct Testimony of Mr. Swetz.

Revised TAC

Q. Has the TAC been modified to reflect all of the changes you describe above?

A. Yes. Please see Schedule SS-ETAC-1E and Schedule SS-GTAC-1G of Mr. Swetz's testimony for the updated TAC reflecting:

1) The continued refund of the protected EDIT under ARAM;

2) The continued refund of the Historic SHARE (increased to reflect 2/3 of the October 31, 2018, balance as approved in the 2018 base rate case;

3) The new flow back of the Historic Mixed Service Deduction proposed to be added in this proceeding;

4) The return on the flow backs as they are returned to customers, calculated in the same manner as approved in the 2018 base rate case; and

5) The fixed flowback of the combined Current SHARE and Current Mixed Service deductions to account for the forecasted future deductions.

V. CONSOLIDATED TAX ADJUSTMENT

Q. What is a Consolidated Tax Adjustment?

A. To state it simply, a Consolidated Tax Adjustment ("CTA") is a ratemaking adjustment designed to pass some or all the benefit of tax savings generated by nonregulated subsidiaries of a consolidated return filing group to the regulated affiliate.

Q. What is the Board's policy regarding CTAs?

A. On January 23, 2014, the Board issued an order opening Docket EO12121072, a generic proceeding to review the applicability and computation of the CTA. On November 22, 2014, the Board issued an order ("November 22 Order") in that docket setting out key computational requirements with respect to the CTA. On December 17, 2014, the Board reaffirmed the January 2014 Order. The Board found that it is appropriate to include a Consolidated Tax Adjustment in utility base rate filings and found that the current CTA policy shall remain in effect with the following modifications:

1) The review period for the calculation shall be for five calendar years including any complete year that is included in the test year;
2) The calculated tax adjustment based on that review period shall be allocated so that the revenue requirement of the company is reduced by 100% of the adjustment; and
3) Transmission assets of the EDCs would not be included in the calculation of the CTA.

Q. Have you included a computation of the CTA that is consistent with Board Order?

A. Yes I have. In Confidential Schedule CP–5, I have provided the detailed computation using the approved Board Order. The resulting CTA reduces rate base by approximately $3 million for electric and $0 for gas. These reductions have been considered in this rate

proceeding. Mr. McFadden has included this amount in rate base as shown in Schedule MPM–03.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

CREDENTIALS
OF
CLIFFORD PARDO
VICE-PRESIDENT OF TAX AND ASSISTANT CONTROLLER
PSEG SERVICES COMPANY

EDUCATIONAL BACKGROUND

In 1987, I graduated from Pace University with a Bachelors of Arts degree in Accounting. In 1992, I earned a Master of Science degree in Taxation from Baruch College. I am also a licensed Certified Public Accountant in the State of Maryland.

WORK EXPERIENCE

From 1995 through 1999, I was employed by J.M. Huber as Director of Tax and Treasury Services. In that position, I was responsible for the world-wide tax and treasury functions. I commenced employment with Public Service Enterprise Group Inc. ("PSEG") in 2000, excluding a two-year break in service between 2007 and 2009, where I am currently employed. From 2000 through 2007, I was the Director of Tax Planning (International Division). My responsibilities as the Director of Tax Planning centered on U.S. and international tax aspects of the Global International Division. In 2010, I rejoined PSEG as the Tax Director and was subsequently promoted to Senior Tax Director. During this time my responsibilities included overseeing the tax research and planning, tax accounting and tax forecasting groups. On January 1, 2018 I was promoted to my current position of Vice President of Tax and Assistant Controller and am responsible for all tax matters for the consolidated PSEG organization.

For completeness, between 2007 and 2008 I was employed by John Wiley & Sons, Inc., as Tax Director where I was responsible for all tax matters, and from 2008 through 2009, I was employed at AES Corporation, as Managing Director – International Tax Planning where I oversaw the international tax group.

I have prepared testimony and supporting data for PSE&G's 2018 electric and gas base rate case filing, filed January 12, 2018, addressing tax aspects of that proceeding as well as many other of PSE&G's filings such as the TAC and Solar 4All filings.

I am also an active participant in Edison Electric Institute Taxation Committee.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule CP-2

	Electric Distribution	Gas Distribution	Total
a - Current Federal Tax Exp	10,633,706.27	($15,483,127.45)	($4,849,421.18)
b - Current State Tax Exp	(18,308,382.31)	$26,674,425.87	$8,366,043.56
c - Deferred Federal Tax Exp	(16,108,371.03)	($40,940,067.48)	($57,048,438.52)
d - Deferred State Tax Exp	51,611,369.84	$801,857.72	$52,413,227.56
e - ITC Expense	(2,977,543.36)	($436,647.26)	($3,414,190.62)
Total Tax Expense	$24,850,779.40	($29,383,558.60)	($4,532,779.20)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule CP-3

Estimated Accumulated Deferred Income Taxes as of May 31, 2024 and November 30, 2024

ACCUMULATED DEFERRED TAXES - ELECTRIC
($000)

	Estimated 5/31/24 Balance	Additional 6 Month Activity	Estimated 11/30/24 Balance
Depreciation & Other	$ (1,050,633)	$ (11,394)	$ (1,062,027)
Repair Deduction	$ (62,527)	$ 9,469	$ (53,058)
Mixed Service Deduction	$ (186,023)	$ (7,287)	$ (193,310)
NJ Corporate Business Tax	$ (477,457)	$ (31,230)	$ (508,687)
Total Electric Accumulated Deferred Taxes	$ (1,776,640)	$ (40,442)	$ (1,817,082)
Proforma Adjustments:			
Adjusted Electric Accumulated Deferred Taxes	$ (1,776,640)	$ (40,442)	$ (1,817,082)

ACCUMULATED DEFERRED TAXES - GAS
($000)

	Estimated 5/31/24 Balance	Additional 6 Month Activity	Estimated 11/30/24 Balance
Depreciation & Other	$ (859,009)	$ (3,471)	$ (862,481)
Repair Deduction	$ (192,748)	$ 8,349	$ (184,399)
Mixed Service Deduction	(168,511)	$ (7,577)	$ (176,088)
NJ Corporate Business Tax	$ (516,711)	$ (21,878)	$ (538,589)
Total Gas Accumulated Deferred Taxes	$ (1,736,979)	$ (24,577)	$ (1,761,557)
Proforma Adjustments:			
Adjusted Gas Accumulated Deferred Taxes	$ (1,736,979)	$ (24,577)	$ (1,761,557)

PSE&G 2023 Base Rate Case
Schedule CP-4
Proposed Historic Mixed Service Flowback

ADIT Balance for Mixed Service	Projected ADIT 2023	Projected 2024 Activity Jan - Aug	Projected Total ADIT as of 8/31/2024
Electric Distribution	184,250,880	6,332,354	190,583,234
Gas Distribution	168,364,589	6,815,476	175,180,065
Total Distribution	352,615,469	13,147,829	365,763,299
Grossed up to Revenues	490,493,072	18,288,815	508,781,887

PSE&G 2023 Base Rate Case
Schedule CP-4
Proposed Fixed Annual Mixed Service Flowback

Summary Current Mixed Service Projection (2025-2029)

	Projected Current Mixed Service				
	2025	2026	2027	2028	2029
ED Tax Deduction	13,043,664	15,395,640	17,042,287	18,832,027	17,965,108
ED Book Depreciation Addback	(5,080,547)	(5,080,547)	(5,080,547)	(5,080,547)	(5,080,547)
Net ED Mixed Service Deduction	7,963,117	10,315,093	11,961,740	13,751,480	12,884,561
Proposed ED Fixed Annual Mixed Service Flowback	**9,000,000**	**9,000,000**	**9,000,000**	**9,000,000**	**9,000,000**
GD Tax Deduction	13,003,683	12,242,142	11,512,713	12,724,871	12,224,328
GD Book Depreciation Addback	(3,458,259)	(3,458,259)	(3,458,259)	(3,458,259)	(3,458,259)
Net GD Mixed Service Deduction	9,545,423	8,783,882	8,054,453	9,266,612	8,766,069
Proposed GD Fixed Annual Mixed Service Flowback	**9,000,000**	**9,000,000**	**9,000,000**	**9,000,000**	**9,000,000**
Total Proposed Distribution Annual Mixed Service Flowback	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000

EXHIBIT P-4

Schedule CP-5

CONFIDENTIAL

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rate And for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
ANN E. BULKLEY
Submitted on Behalf
of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

December 29, 2023

P-5

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SUMMARY OF ANALYSIS AND CONCLUSIONS 3

III. REGULATORY GUIDELINES 7

IV. CAPITAL MARKET CONDITIONS 11

A. Inflationary Expectations in Current and Project Capital Market Conditions 13

B. The Use of Monetary Policy to Address Inflation 16

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return 16

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments 19

E. Conclusion 23

V. PROXY GROUP SELECTION 24

VI. COST OF EQUITY ESTIMATION 27

A. CAPM Analysis 30

B. Constant Growth DCF Model 35

C. Bond Yield Plus Risk Premium Analysis 40

VII. REGULATORY AND BUSINESS RISKS 43

A. Management Performance Recognition 43

B. Capital Expenditures 46

C. Regulatory Risk 49

VIII. CAPITAL STRUCTURE AND PROPOSED INTEREST COST RECONCILIATION DEFERRAL 56

A. Capital Structure 56

B. Interest Cost Reconciliation Deferral Mechanism 59

IX. CONCLUSIONS AND RECOMMENDATION 60

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
ANN E. BULKLEY
PRINCIPAL, THE BRATTLE GROUP

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am employed by The Brattle Group ("Brattle") as a Principal.

Q. On whose behalf are you submitting this Prepared Direct Testimony?

A. I am submitting this testimony before the New Jersey Board of Public Utilities ("BPU" or the "Board") on behalf of Public Service Electric and Gas Company ("Public Service" or "the Company"), a wholly-owned subsidiary of Public Service Enterprise Group, Inc. ("PSEG").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Schedule AEB-1.

Q. Please describe the purpose of your testimony.

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for the Company and to assess the reasonableness of its proposed capital structure for ratemaking purposes.

Q. Are you sponsoring any schedules in support of your Direct Testimony?

A. Yes. My analysis and recommendations are supported by the data presented in Schedule AEB-2 through Schedule AEB-13, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. I estimated the Company's Cost of Equity ("COE") by applying several traditional COE estimation methodologies to a proxy group of comparable utilities, including Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration: (1) the Company's actual and anticipated capital expenditure requirements, and (2) the Company's regulatory risk as compared with the proxy group. Finally, I considered the Company's capital structure as compared with the capital structures of the proxy companies.[1] While I did not make any specific adjustments to the ROE recommendation for any of these factors individually, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

[1] The selection and purpose of developing a group of comparable companies will be discussed in detail in Section V of my Direct Testimony.

Q. How is the remainder of your Direct Testimony organized?

A. Section II provides a summary of my analyses and conclusions. Section III reviews the regulatory guidelines pertinent to the development of the cost of capital. Section IV discusses current and projected capital market conditions and the effect of those conditions on the cost of equity. Section V explains the selection of a proxy group of combination electric and natural gas distribution utilities. Section VI describes the analyses and analytical basis for the recommendation of an appropriate ROE for Public Service. Section VII provides a discussion of specific regulatory, business and financial risks that directly affect the ROE to be authorized for the Company in this case. Section VIII addresses the Company's capital structure as compared with the capital structures of the utility operating company subsidiaries of the proxy group companies. Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. The key factors that I considered in my cost of equity analyses and recommended ROE for the Company in this proceeding are:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[2] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and projected capital market conditions on ROE estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's required COE should be a forward-looking estimate, these analyses rely on forward-looking inputs and assumptions (e.g., projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis)

[2] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

- The Company's regulatory, business, financial and regulatory risks relative to the proxy group of comparable companies, and the implications of those risks in determining an appropriate ROE for the Company over the period during which rates will be in effect.

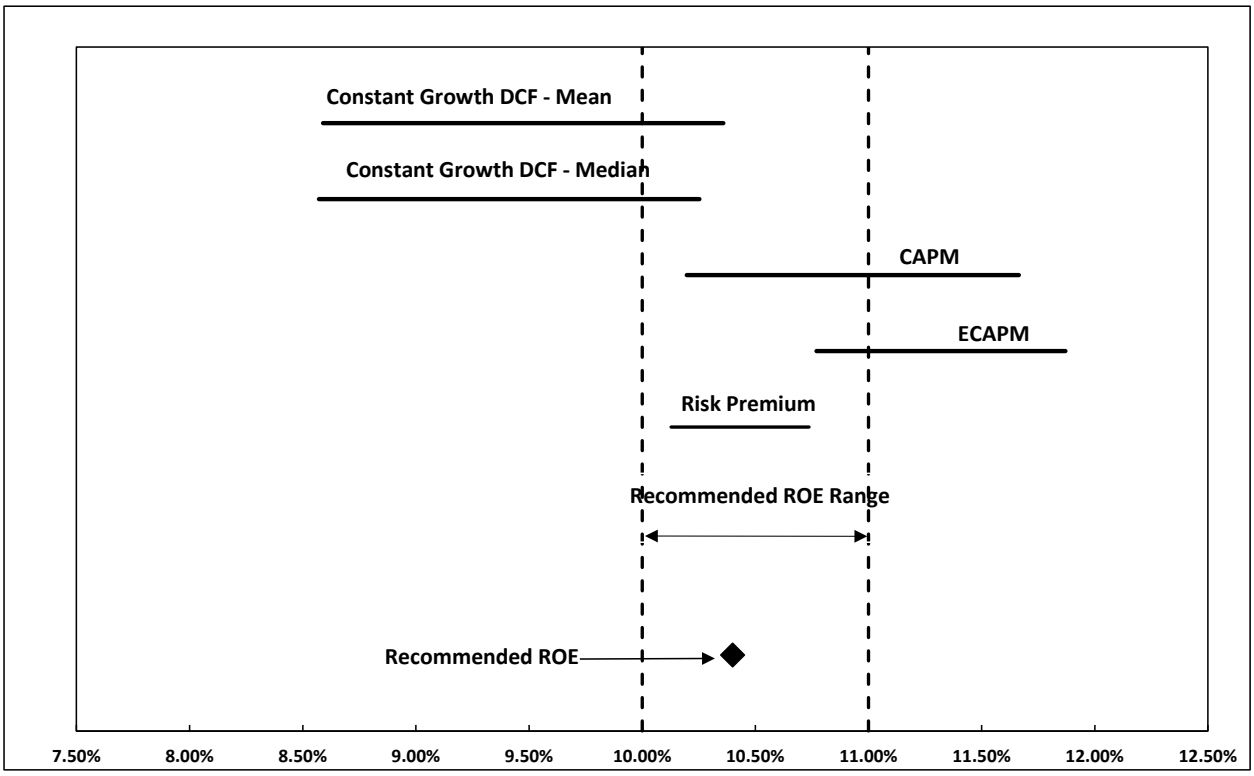
Q. Please explain how you considered those factors.

A. I relied on the range of results produced by the Constant Growth DCF model, the CAPM and ECAPM, and a Risk Premium analysis. As shown in Figure 1, these COE estimation models produce a wide range of results. My conclusion as to the appropriate ROE for Public Service within that range of results is based on the Company's business and financial risk relative to the proxy group and my assessment of market conditions. Although the companies in my proxy group are generally comparable to Public Service, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's business, financial and regulatory risk in aggregate relative to that of the proxy group companies when determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. Please summarize the results of the COE estimation models that you considered to establish the range of the COE for Public Service.

A. Figure 1 summarizes the range of results produced by the Constant Growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses.

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1 (and in Schedule AEB-2), the range of results produced by the COE estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q. Are prospective capital market conditions expected to affect the results of the cost of equity for Public Service during the period in which the rates established in this proceeding will be in effect?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.
- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least over the next year in response to inflation.
- Over the past year, utilities have underperformed the broader market. For example, between January 1, 2023 and November 6, 2023, the S&P 500 Utilities Index

declined by 12.48 percent. During the same period, the S&P 500 Index increased by 13.71 percent. It is reasonable to expect this relationship to continue, as interest rates remain high or increase and investors have the option to invest in lower risk investments at similar returns offered on utility equity.

- Since utility dividend yields are less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, it is likely that utility share prices will continue to decline.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.
- A decline in utility stock prices will increase the dividend yields and thus, all else equal, the cost of equity estimates produced by the DCF model.
- Consequently, the results of the DCF model, which relies on current utility share prices, is likely to understate the cost of equity during the period that the Company's rates will be in effect.
- Furthermore, expected market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which, rely on interest rates as a direct input into the models and thus may better reflect the market conditions expected during the period that the Company's rates will be in effect.
- Rating agencies have cited increased risk in the utility sector due to increased interest rates, inflation and elevated capital expenditures.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for Public Service.

Q. What is your conclusion regarding the appropriate authorized ROE for Public Service in this proceeding?

A. Based on the analytical results presented in Figure 1, my assessment of current and anticipated capital market conditions, and the Company's business, financial and regulatory risk relative to proxy group companies, I conclude that a ROE in the range of 10.00 percent to 11.00 percent is reasonable. Considering underlying market conditions and the business, financial and regulatory risk factors facing Public Service, including the Company's significant capital expenditures, the Company's requested ROE of 10.40 percent is conservative.

Q. Please summarize your analysis of the appropriate ratemaking capital structure for the Company.

A. Based on the analysis presented in Section VIII of my testimony, I conclude that Public Service's proposed 55.50 percent common equity ratio is reasonable. To determine if the Company's requested capital structure was reasonable, I reviewed the capital structures of the utility subsidiaries of the proxy companies. As shown in Schedule AEB-13, the results of that analysis demonstrate that the eight quarter (i.e., Q3/2021 Q2/2023) average equity ratios for the utility operating companies of the proxy group range from 47.21 percent to 66.21 percent. Comparing the recommended equity ratio to the proxy group demonstrates that the Company's requested equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies.

III. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of equity for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope and Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

[3] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

Q. Has the Board provided similar guidance in establishing the appropriate return on common equity?

A. Yes. Section 48:2-21.25 of the 2022 New Jersey Revised Statutes states that a "Base rate case" is defined as a means of "determining the level of revenues necessary to afford the public utility an opportunity to earn a fair and reasonable rate of return on prudently incurred capital investment in the public utility's rate base."[4] Furthermore, in its decision in Docket No. ER12111052 for Jersey Central Power and Light Company ("JCP&L"), the Board noted the following:

> it is incumbent upon this Board to define a fair rate of return for JCP&L commensurate with risks faced by similar companies, sufficient to attract capital and maintain the financial integrity of the enterprise. As the New Jersey Supreme Court has recognized, a privately owned public utility is a complex mechanism that exists to serve a public need but to do so it must have investor appeal. It must be allowed a reasonable return on its investment so that it may have borrowing power at normal business rates to finance its day-to-day operations. See Daaleman v. Elizabethtown Gas Co., 77 N.J. 267, 272 (1978).[5]

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric and natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

---

[4] 2022 New Jersey Revised Statutes, Section 48:2-21.25.

[5] BPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Agenda Date March 12, 2015, at 71.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE that is not in line with authorized ROEs for other natural gas and electric utilities, on a risk adjusted basis, can inhibit the utility's ability to attract capital for investment in New Jersey.

Q. Is the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q. Are you aware of any utilities that have experienced either a credit rating downgrade or negative market response related to the financial effects of a rate case decision?

A. Yes. ALLETE, Inc.[6], CenterPoint Energy Houston Electric[7], and Pinnacle West Capital Corporation ("PNW")[8] each received credit rating downgrades following a rate case decision for reasons that included a below average authorized ROE. In the case of PNW, the market had a strong negative response to the rate case decision for its operating subsidiary, Arizona Public Service Company ("APS"), which included an 8.70 percent ROE determination.[9]

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the COE analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Public Service's electric and natural gas operations.

---

6 Moody's Investors Service, "Credit Opinion: ALLETE, Inc. Update following downgrade," at 3 (April 3, 2019).

7 FitchRatings, "Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative," February 19, 2020.

8 S&P Capital IQ Pro; FitchRatings, "Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative," October 12, 2021; and Moody's Investors Service, "Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative," (Nov. 17, 2021).

9 S&P Global Market Intelligence, "Pinnacle West shares tumble after regulators slash returns in rate case," October 7, 2021.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Board's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The COE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the COE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the COE estimation models to estimate the required return for the subject company.

As a result, it is important to consider the effect of these conditions on the COE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the COE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The COE for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: 1) relatively high inflation, 2) changes in monetary policy, and 3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the COE estimation models. In this section, I discuss each of these factors and how they affect the models used to estimate the cost of equity for regulated utilities.

Q. What effect do current and prospective market conditions have on the COE for Public Service?

A. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation, and the Federal Reserve's changes in monetary policy, contribute to an expectation of increased market risk and an increase in the cost of the investor-required return. It is essential that these factors be considered in setting a forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased from the pandemic lows seen in 2020 are expected to remain elevated over the near term in direct response to the Federal Reserve's monetary policy. There is a strong historical inverse correlation

between interest rates (i.e., yields on long-term government bonds) and the share prices of utility stocks (i.e., as utility share prices decline, utility dividend yields increase). Since the yields on long-term government bonds currently exceed the dividend yields of utilities, and historically long-term government bond yields have been lower than the dividend yields of utilities, it is reasonable to expect that utility investors' cost of equity is increasing. Because the cost of equity in this proceeding is being estimated for the future period that the Company's rates will be in effect, and because the cost of equity is expected to increase over the near term for utilities, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, will understate the cost of equity required by investors during the future period that the Company's rates determined in this proceeding will be in effect.

A. Inflationary Expectations in Current and Project Capital Market Conditions

Q. Has inflation increased significantly over the past year?

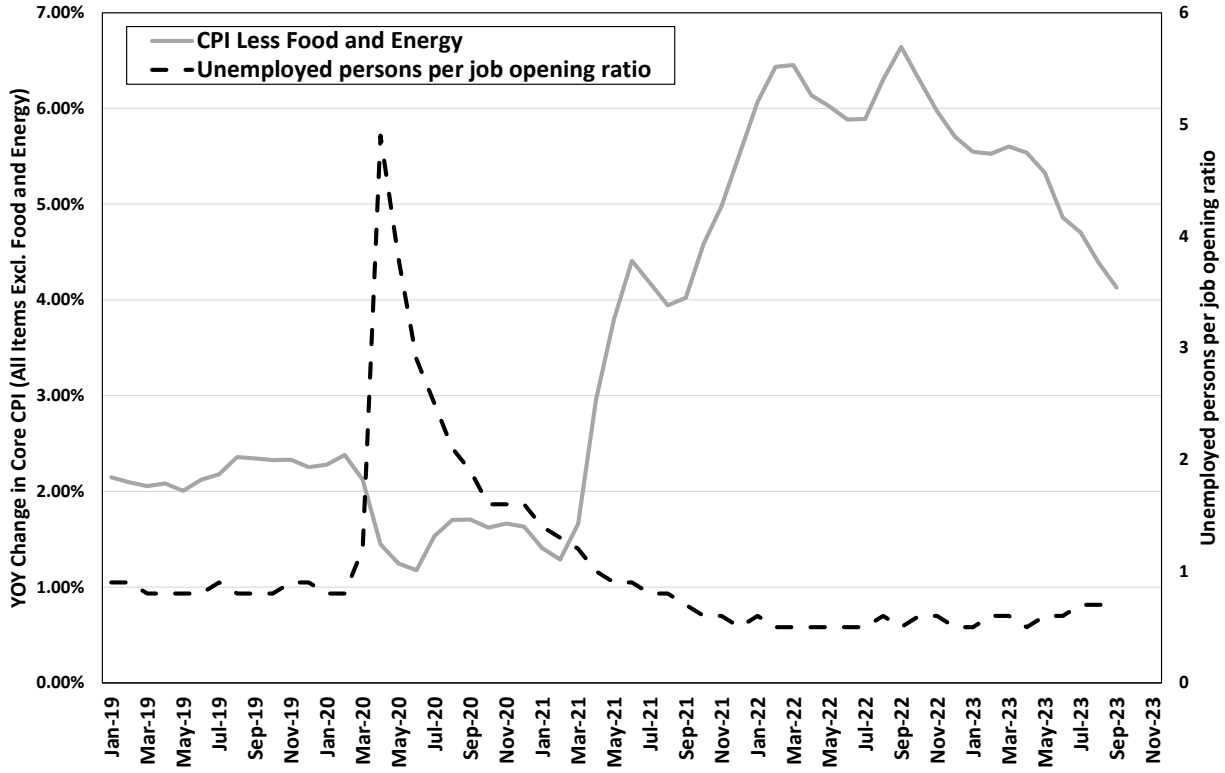
A. Yes. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[10] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, core inflation continues to remain significantly above the Federal Reserve's target level of 2.0 percent.

Finally, as shown in Figure 2, I also considered the ratio of unemployed persons per job opening, which is currently 0.7 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor

[10] Figure 2 presents the year-over-year ("YOY") change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to September 2023[11]



Q. What are the expectations for inflation over the near-term?

A. Despite the declines from 40-year highs, the Federal Reserve has indicated that it expects inflation will remain above its target level over at least the next year and that monetary policy will remain restrictive in order to reduce inflation. For example, Federal Reserve Chair Powell observed at the Federal Open Market Committee (FOMC) meeting in September 2023 that while

[11] Source: Bureau of Labor Statistics.

inflation is down from its recent highs, it remains significantly above the Federal Reserve's long-term target:

> Inflation remains well above our longer-run goal of 2 percent. Based on the Consumer Price Index, or CPI, and other data, we estimate that total (Personal Consumption Expenditures) PCE prices rose 3.4 percent over the 12 months ending in August; and that, excluding the volatile food and energy categories, core PCE prices rose 3.9 percent. Inflation has moderated somewhat since the middle of last year, and longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. Nevertheless, the process of getting inflation sustainably down to 2 percent has a long way to go. The median projection in the SEP for total PCE inflation is 3.3 percent this year, falls to 2.5 percent next year, and reaches 2 percent in 2026.[12]

After the September 2023 and the November 2023 meetings, Chair Powell kept open the possibility of additional rate increases, considering even December this year, or thereafter if it is appropriate to do so. Further, at the September 2023 meeting, he noted that interest rates would likely remain positive for some time:

> First of all, interest rates – real interest rates are, are positive now. They're meaningfully positive, and that's a good thing. We need policy to be restrictive so that we can get inflation down to target. Okay. And we need - we're going to need that to remain to be the case for some time. So I think, you know – remember that the – of course, the SEP [Summary of Economic Projections] is not a plan that is negotiated or discussed, really, as a plan. It's accumulation, really, and what you see are the medians. It's accumulation of individual forecasts from 19 people, and then what you're seeing are the medians. So I wouldn't want to, you know, bestow upon it the idea that, that it's really a plan. But what it reflects, though, is that economic activity's been stronger than we expected – stronger than I think everyone expected. And, so what you're – what you're seeing is, this is what people believe, as of now, will be appropriate to achieve what we're looking to achieve, which is progress toward our – toward our inflation goal, as you see in the SEP.[13]

---

[12] Federal Reserve, Transcript of Chair Powell's Press Conference, September 20, 2023, p 2; https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20230920.pdf

[13] *Id.*, at 6.

Similarly, he noted the following at the November 2023 meeting:

> The fact is the committee is not thinking about rate cuts right now at all. We're not talking about rate cuts. We're still very focused on the first question, which is 'have we achieved a stance of monetary policy that's sufficiently restrictive to bring inflation down to 2% over time, sustainably?' That is the question we're focusing on.[14]

B. The Use of Monetary Policy to Address Inflation

Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Beginning in March 2022 and through May 3, 2023, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.50 percent to a range of 5.00 percent to 5.25 percent.[15] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to increased levels of

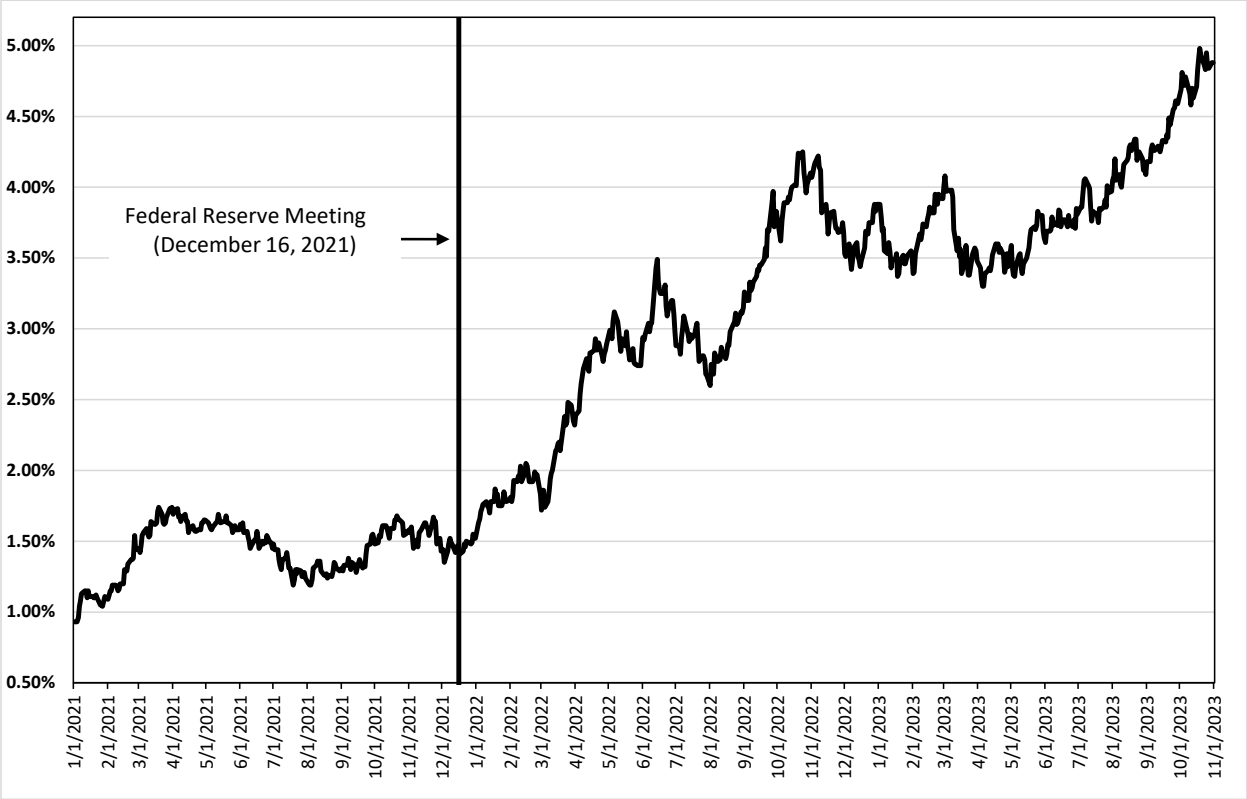
---

[14] CNBC "Full recap: Fed leaves rates unchanged, Powell discusses December decision", November 1, 2023.

[15] Federal Reserve, Press Releases, March 16, 2022, May 4, 2022, June 15, 2022, September 22, 2022, November 2, 2022, February 1, 2023, March 22, 2023 and May 3, 2023.

inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has more than tripled, increasing from 1.47 percent on December 15, 2021, to 4.88 percent at the end of October 2023.

Figure 3: 10-Year Treasury Bond Yield—Janaury 2021– October 2023[16]



Q. What have equity analysts said about long-term government bond yields?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, in the most recent Big Money poll released by *Barron's* in October 2023, which surveys money managers regarding the outlook for the next twelve months, two-thirds of the money managers surveyed expect the yield on the 10-year Treasury bond

[16] S&P Capital IQ Pro.

to be at least 4.50 percent in October 2024.[17] Similarly, according to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yields on the 10-year and 30-year Treasury bonds are approximately 3.90 percent and 4.20 percent, respectively, through the first quarter of 2025.[18] Therefore, investors expect interest rates to remain elevated for at least the next 18 months. As a result, it is reasonable to expect that if government bond yields remain elevated, the COE will be increasing above the levels experienced in the 2020 and 2021 lower interest rate environment.

Q. How have interest rates and inflation changed since the Company's last rate case?

A. As shown in Figure 4, when the Board approved the settlement agreement and authorized an ROE of 9.60 percent in the Company's 2018 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 3.29 percent at the time of the Board decision, and core inflation was 2.13 percent. However, since the Company's last rate proceeding, long-term interest rates have increased approximately 155 basis points and inflation has increased approximately 200 basis points.

Figure 4: Change in Market Conditions Since Company's Last Rate Case

Docket	Decision Date	Federal Funds Rate	30-Day Average of 30-Year Treasury Bond Yield	Core Inflation Rate	Authorized ROE
ER18010029 & GR18010030	10/29/2018	2.20%	3.29%	2.13%	9.60%
Current	10/31/2023	5.33%	4.84%	4.13%	

[17] Jasinski, Nicholas, Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds", October 27, 2023. https://www.barrons.com/articles/big-money-poll-stock-market-bonds-economy-outlook-375aebae?mod=hp_MAG

[18] *Blue Chip Financial Forecasts*, Vol. 42, No. 11, November 1, 2023, p. 2.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes. Interest rates and utility share prices are inversely correlated which means, for example, that an increase in interest rates will result in a decline in the share prices of utilities. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (i.e., increases in bond yields resulted in the decline of utility share prices).[19]

Q. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A. Equity analysts project that utilities will underperform the broader market given high inflation and the recent increases in interest rates. For example, Fidelity Investments classifies the utility sector as underweight[20] and Bank of America recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[21] Moreover, as referenced above, the professional investors surveyed by *Barron's* in its most recent Big Money poll selected the utility sector as one of the four equity sectors that they liked the least over the next twelve months, indicating they are projecting that utilities will underperform the broader market in 2024.[22]

---

[19] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, 11 Mar. 2021, www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.

[20] Fidelity Investments. "Fourth Quarter 2023 Investment Research Update." October 19, 2023.

[21] Dumoulin-Smith, Julien, *et. al*. "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes." BofA Securities, September 6, 2023.

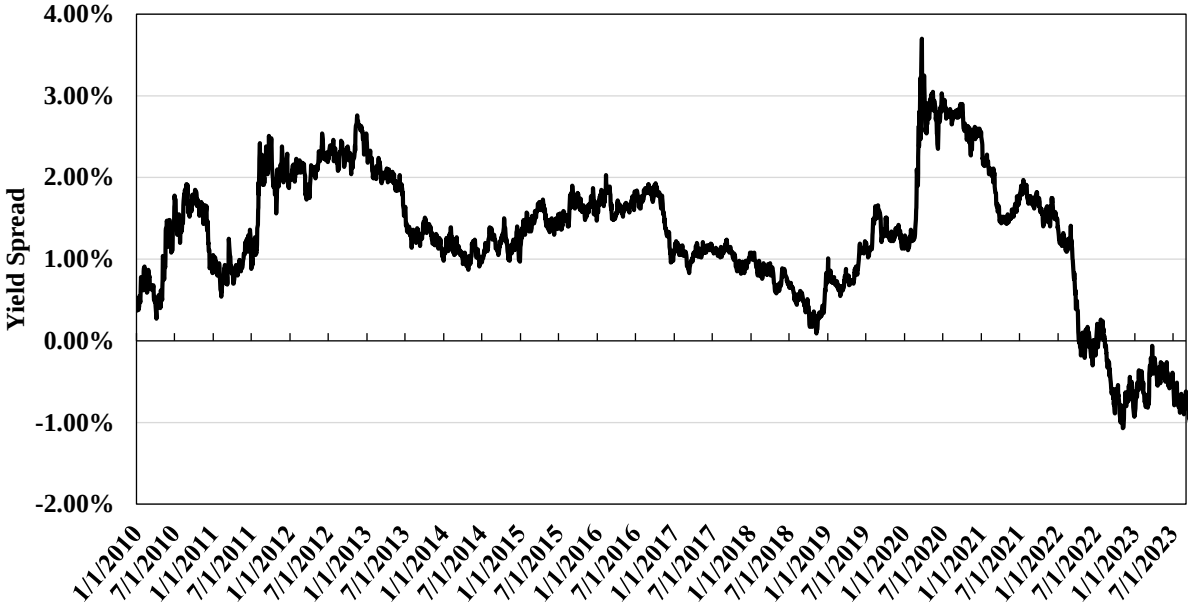
[22] Jasinski, Nicholas, Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds", October 27, 2023. https://www.barrons.com/articles/big-money-poll-stock-market-bonds-economy-outlook-375aebae?mod=hp_MAG

Q. Why do equity analysts expect the utility sector to underperform over the near-term?

A. While interest rates have increased substantially over the past year, the valuations of utilities have remained elevated and have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through October 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of October 31, 2023 was negative 1.26 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.25 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – October 2023[23]



Q. Do you have any further context as to how unlikely it is to have a negative yield spread of this magnitude?

A. Yes. For further context as to how unlikely it is to have a yield spread of negative 1.26 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of negative 1.26 percent has a z-score of -2.95, indicating that a yield spread of negative 1.26 percent is over 2 standard deviations from the mean of 1.25 percent.[24] In other words, 95 percent of the daily yield spread observations from 2010 through October 2023 fall between -0.45 percent and 2.95 percent, with the current yield spread of negative 1.26 percent being outside of that range. Thus, the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

[23] S&P Capital IQ Pro and Bloomberg Professional.

[24] The z-score is calculated as: (yield spread at October 31, 2023 minus average yield spread 2010 through October 2023)/standard deviation of yield spread from 2010 through October 2023. This equals: (-1.26 minus 1.25)/0.0085.

Q. Have regulatory commissions acknowledged that the DCF model might understate the COE given the current capital market conditions of high inflation and increasing interest rates?

A. Yes. For example, in its May 2022 decision in establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission ("PPUC") specifically concluded that the current capital market conditions of high inflation and increasing interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[25]

[25] Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc., Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

Similarly, the Massachusetts Department of Public Utilities ("MDPU") in a recent rate case for NSTAR Electric Company concluded that given the recent increase in interest rates there was "greater certainty" the results of the DCF model were understating the cost of equity for NSTAR Electric Company.[26]

E. Conclusion

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A. Investors expect long-term interest rates to remain relatively high through at least 2024, in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already substantially greater than utility stock dividend yields, the share prices of utilities will likely decline, which is the reason a number of equity analysts have classified the sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

[26] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, November 30, 2022, p. 385-386.

V. PROXY GROUP SELECTION

Q. Please provide a brief profile of Public Service.

A. Public Service is a wholly-owned subsidiary of PSEG that provides electric transmission and distribution services to approximately 2.3 million retail customers and gas distribution service to approximately 1.9 million retail customers in New Jersey, including the six largest cities.[27] For the year ended December 31, 2022, Public Service had revenue of $7.9 billion.[28] Public Service's current long-term issuer ratings are: (1) S&P A- (Outlook: Stable); and (2) Moody's Investor's Service A3 (Outlook: Stable).[29]

Q. Why have you used a group of proxy companies to estimate the cost of equity for the Company?

A. In this proceeding, I focus on estimating the cost of equity for Public Service, a rate-regulated subsidiary of PSEG. Because the cost of equity is a market-based concept and because Public Service's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if Public Service was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are

[27] Source: Public Service Enterprise Group, Inc., 2022 SEC Form 10-K, at 3.

[28] Source: Public Service Enterprise Group, Inc., 2022 SEC Form 10-K, at 66.

[29] Source: S&P Capital IQ Pro and Moody's Investor's Service (accessed November 7, 2023).

substantially comparable to the Company's, and thus provide a reasonable basis to derive and estimate the appropriate ROE for the Company.

Q. How did you select the companies included in your proxy group?

A. I began with the group of 36 publicly traded companies that Value Line classifies as Electric Utilities and applied the following screening criteria to select a group of risk-comparable companies that:

- pay consistent quarterly cash dividends that have not been reduced in the last three years, since companies that do not meet this criteria cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- derive at least 70 percent of the company's total operating income from regulated operations;
- derive at least 10 percent of the company's total regulated operating income from gas distribution operations; and
- were not party to a merger or transformative transaction during the analytical period considered.

Q. What is the composition of your proxy group?

A. The screening criteria discussed above resulted in a proxy group consisting of the companies shown in Figure 6 below.

Figure 6: Proxy Group

Company	Ticker
Ameren Corporation	AEE
Avista Corporation	AVA
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
Eversource Energy	ES
MGE Energy, Inc.	MGEE
NorthWestern Corporation	NWE
Sempra Energy	SRE
Southern Company	SO
Wisconsin Energy Corporation	WEC
Xcel Energy Inc.	XEL

Q. Do your screening criteria result in a proxy group that is risk comparable to Public Service?

A. Yes, they do. The overall purpose of developing a set of screening criteria is to select a proxy group of companies that align with the financial and operational characteristics of Public Service and that investors would view as comparable to the Company. I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size with establishing a proxy group of companies that are comparable in business and financial risk to Public Service. The Company operates as a combination electric and gas utility and is viewed by investors as a combination company. The Company raises capital as a combination company, and does not issue separate debt or equity for electric and gas operations. Thus, a proxy group consisting combination electric and gas utilities is most risk comparable to Public Service and resulted in the group of 13 companies shown in Figure 6.

VI. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return ("ROR").

A. The ROE is the cost rate applied to the equity capital in the ROR. The ROR for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (i.e. book values) in the utility's capital structure. While the costs of debt and preferred stock can be directly observed, the COE is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required COE determined?

A. The required COE is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's COE falls within the range of results produced by multiple analytical techniques. The key consideration in determining the COE is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to establish your recommended ROE in this proceeding?

A. I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, and a Bond Yield Plus Risk Premium analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Why is it important to use more than one analytical approach?

A. Because the COE is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the COE, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the COE, and I use multiple approaches to estimate the COE. As a practical matter, however, all the models available for estimating the COE are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the COE. For example, Copeland, Koller, and Murrin[30] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[31] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches**.**

Q. Do current market conditions increase the importance of using more than one analytical approach?

A. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. While the share prices of utilities have declined, the negative yield spread noted above is an indication that the share prices have not declined sufficiently to account for the recent rise in interest rates. As a result, equity analysts expect the utility sector to continue to underperform over the next year. Given the expected underperformance, it is reasonable to conclude that the DCF model is likely understating the forward-looking cost of equity because the

---

[30] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[31] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

model relies on historical share prices. The CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses offer some balance through the use of interest rates as a direct input into the models and therefore may better reflect the market conditions expected when the Company's rates are in effect. These recent changes in market conditions highlight the benefit of using multiple models since each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. Therefore, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

Q. Has the Board made similar findings regarding the reliance on multiple models?

A. Yes. It is my understanding that in its order in Docket No. ER12111052 for Jersey Central Power and Light Company, the Board noted that rate of return experts use a number of models including the DCF, CAPM, Risk Premium and Comparable Earnings to estimate the return required by investors. Specifically, the Board noted:

> In determining the cost of equity capital for a regulated utility, rate of return experts typically use a variety of financial models to simulate the returns assertedly required by investors. These include Discounted Cash Flow (DCF) models, Risk Premium models, Capital Asset Pricing Models (CAPM), Comparable Earnings models and variations thereof. However, it is widely acknowledged that these economic models constitute estimates, which, although probative, are not necessarily precise. The imprecision in the estimates provided by these models is more pronounced as a result of the current economic environment still recovering from the Great Recession, characterized by some as the worst economy since the Great Depression.[32]

In the order, the Board accepted an ROE of 9.75 percent for JCP&L which was supported by the ALJ and ultimately recommended by Staff based on a review of each of

[32] BPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

the model results presented by the witnesses in the case and recently authorized ROEs in other jurisdictions.[33] In supporting the recommendation of Staff, the ALJ concluded that the results of each model are affected by multiple factors including current market conditions. Specifically, the ALJ concluded that:

> [e]ach method has multiple factors, and the parties have offered numerous criticisms of the choices made by opposing expert witnesses. A key consideration concerns the time period used by the experts in selecting a dividend yield under the DCF model or the risk-free rate under the CAPM method due to the fact that interest rates have been at historic lows in recent years. For example, with the CAPM method, Ms. Ahern used interest rates on thirty-year Treasury bonds going as far back as 1926 producing an average of 5.32 percent, which led to a risk free rate of 4.17 percent. As Mr. Kahal points out, rates on thirty-year Treasury bonds have been closer to 3.00 percent in recent years. In contrast, Mr. Kahal based the dividend yield under his DCF analysis on results from the six months ending April 2013. Development of the dividend yield from data during a period of historically low interest rates may produce a result which is lower than will prevail when the new rates are in effect. Mr. O'Donnell's analysis in this respect is similar to that of Mr. Kahal.[34]

Thus, the Board, an ALJ, and Board Staff have all recognized the importance of considering the results of each model presented in the rate case because market conditions can have an effect on the results produced by each of the ROE estimation models.

A. CAPM Analysis

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the COE for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, systematic risk of that security. Systematic risk is the risk inherent in the entire market or market

---

[33] *Id.*, at 10.

[34] BPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Initial Decision, January 8, 2015, at 27.

segment—which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [1]$$

Where:

K_e = the required market COE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by Beta. Beta is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [2]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (i.e., Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.84 percent;[35] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2024 through the first quarter of 2025, which is 4.44 percent;[36] and (3) the average projected 30-year U.S. Treasury bond yield for 2025 through 2029, which is 3.80 percent.[37]

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown Schedule AEB-5, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported by Bloomberg were calculated using ten years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

As shown in Schedule AEB-5, I also considered an additional CAPM analysis that relies on the long-term average utility Beta coefficient for the companies in my proxy group. As shown in Schedule AEB-6, the long-term average utility Beta coefficient was calculated as an average of the Value Line Beta coefficients for the companies in my proxy group from 2013 through 2022.

Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the Market Risk Premium ("MRP") as the difference between the implied expected equity market return and the risk-free rate. As shown in Schedule AEB-7, the expected market return is calculated using the constant growth DCF model discussed below as applied to

---

[35] Bloomberg Professional as of October 31, 2023.

[36] Blue Chip Financial Forecasts, Vol. 42, No. 11, at 2 (November 1, 2023).

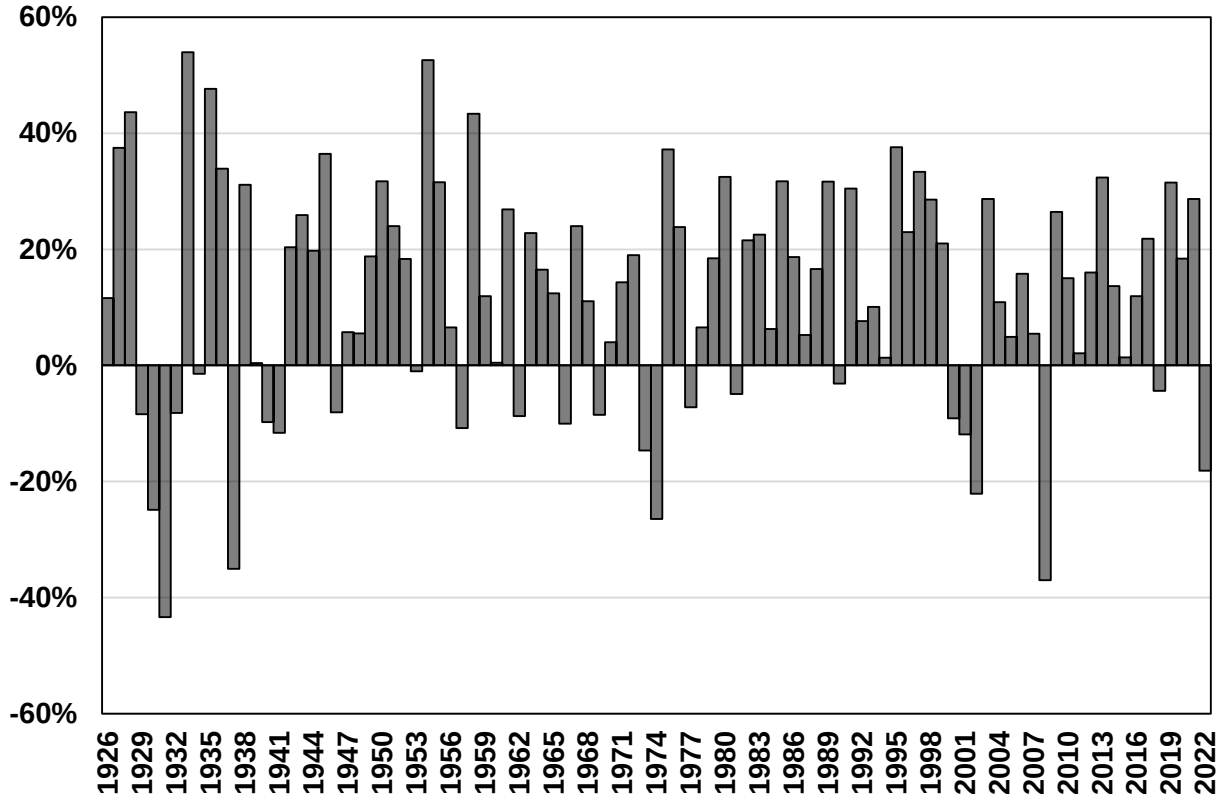
[37] Blue Chip Financial Forecasts, Vol. 41, No. 6, at 14 (June 1, 2023).

the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.88 percent and a weighted long-term growth rate of 10.51 percent, the estimated required market return for the S&P 500 Index as of October 31, 2023 is 12.49 percent.

Q. How does the current expected market return of 12.49 percent compare to observed historical market returns?

A. Given the range of annual equity returns that have been observed over the past century (shown in Figure 7), a current expected return of 12.49 percent is not unreasonable. In 50 out of the past 97 years (or roughly 52 percent of observations), the realized equity return was at least 12.49 percent or greater**.**

Figure 7: Realized U.S. equity market returns (1926-2022) [38]



[38] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook**.**

Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM or alternatively referred to as the Zero-Beta CAPM[39] in estimating the COE for Public Service. The ECAPM calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [3] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [3]$$

Where:

k_e = the required market COE;

β = Adjusted Beta coefficient of an individual security;

rf = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In essence, the Empirical form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[40]

---

[39] *See* Roger A. Morin, New Regulatory Finance at 189, Public Utilities Reports, Inc. (2006).

[40] *Id.*, at 191.

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the Bloomberg, Value Line, and long-term average Beta coefficients.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 8 (see also Schedule AEB-5), my traditional CAPM analysis produces a range of returns from 10.20 percent to 11.66 percent. The ECAPM analysis results range from 10.77 percent to 11.87 percent.

Figure 8: CAPM and ECAPM Results

	Current Risk-Free Rate (4.84%)	Q1 2024 – Q1 2025 Projected Risk-Free Rate (4.44%)	2025-2029 Projected Risk-Free Rate (3.80%)
		CAPM	
Value Line Beta	11.66%	11.62%	11.55%
Bloomberg Beta	10.84%	10.75%	10.61%
Long-term Avg. Beta	10.47%	10.37%	10.20%
		ECAPM	
Value Line Beta	11.87%	11.84%	11.79%
Bloomberg Beta	11.25%	11.18%	11.08%
Long-term Avg. Beta	10.98%	10.90%	10.77%

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [4]$$

Where P_0 represents the current stock price, $D_1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [5]$$

Equation [5] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ("P/E") ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended October 31, 2023.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three commonly referenced sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Yahoo! Finance; and (3) Value Line Investment Survey.

Q. How did you calculate the range of results for the Constant Growth DCF Models?

A. I calculated the low result for my DCF model using the minimum growth rate (*i.e.*, the lowest of the Value Line, Yahoo! Finance, and Zacks earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rate from all three sources for each proxy group company.

Q. What were the results of your Constant Growth DCF analyses?

A. Figure 9 (see also Schedule AEB-2 and 4) summarizes the results of my DCF analyses. As shown in Figure 9, the median and mean DCF results range from 9.32 percent to 9.84 percent, and the median high and mean high results are in the range of 10.05 percent to 10.55 percent. While I also summarize the low DCF results, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the COE, I do not believe it is appropriate to consider the low DCF results at this time.

Figure 9: Constant Growth Discounted Cash Flow Results

Constant Growth DCF - Mean			
	Min Growth Rate	**Mean Growth Rate**	**Max Growth Rate**
30-Day Average	8.78%	9.69%	10.55%
90-Day Average	8.57%	9.47%	10.34%
180-Day Average	8.42%	9.32%	10.19%
Constant Growth DCF - Median			
	Min Growth Rate	**Mean Growth Rate**	**Max Growth Rate**
30-Day Average	8.87%	9.84%	10.44%
90-Day Average	8.53%	9.60%	10.27%
180-Day Average	8.31%	9.48%	10.05%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the Constant Growth DCF model is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates increase, it is important to consider the results of the DCF models with caution. This means that the results of the current DCF models are below where they would otherwise be under more normal market conditions. Therefore, while I have given weight to the results of the Constant Growth DCF model, my recommendation also gives weight to the results of other COE estimation models.

C. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the COE as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utilities as the historical measure of the COE to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes, there are. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase, the equity risk premium decreases, and vice versa. Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the

relevant measure of interest rates, the risk premium simply would be the difference between those two points.[41]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes, it is. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 10 below, from 1980 through October 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

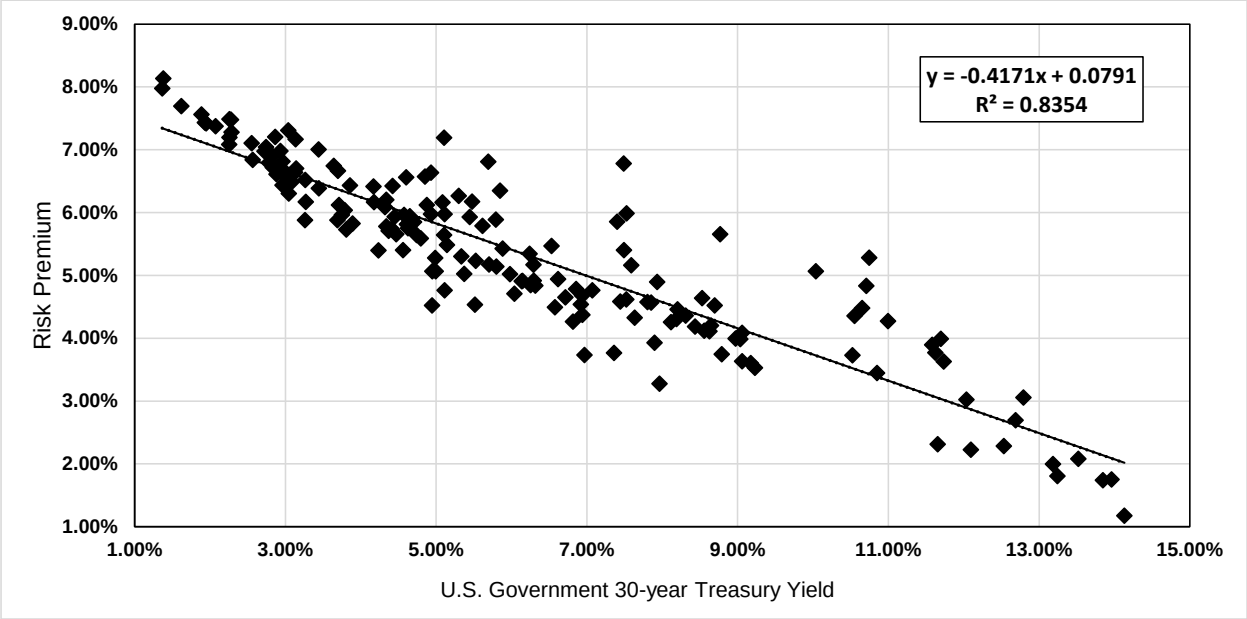
b = slope term

[41] *See* S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return at 66, Financial Management (Spring 1986).

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from all of electric utility rate cases from 1980 through October 2023 as reported by Regulatory Research Associates ("RRA").[42] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 10: Risk Premium Results



As shown in Schedule AEB-8, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 4.84 percent), the risk premium would be 5.89 percent, resulting in an estimated ROE of 10.74 percent. Based on the near-term (Q1 2024 – Q1 2025) projections of the 30-year U.S. Treasury bond yield (i.e., 4.44 percent), the risk premium would be 6.06 percent, resulting in an estimated ROE of 10.50 percent. Based on longer-term (2025 – 2029) projections of the 30-year U.S. Treasury bond yield (i.e., 3.80 percent), the risk premium would be 6.33 percent, resulting in an estimated ROE of 10.13 percent.

[42] This analysis began with a total of 2,379 cases and was screened to eliminate limited issue rider cases, transmission-only cases, and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 1,747 cases.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for the Company?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for Public Service. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VII. REGULATORY AND BUSINESS RISKS

Q. Taken alone, do the results from the COE estimation models for the proxy group provide an appropriate estimate of the COE for the Company?

A. No. These analyses provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Management Performance Recognition

Q. Why is management performance important to consider in determining the ROE of a company?

A. Regulatory commission decisions can influence the overall operations of the utilities that are under its regulation. In rate proceedings, the regulatory commissions review all costs to determine the reasonableness of the overall operating cost of the Company for the benefits of customers. In addition to the actual costs incurred, it is important that the regulatory commission consider the overall management performance and service quality that is derived from those costs. Regulation that is constructive and supportive of management's ability to achieve low costs and high overall service quality plays an important role in utility regulation and the continued success of top performing companies.

Q. Has Public Service conducted any analysis of its management performance as compared with a benchmark group?

A. Yes. The Direct Testimony of Public Service witness Mr. Adams describes in detail the performance benchmarking analysis that was undertaken and summarizes the results for Public Service as compared with national, regional, as well as a New Jersey specific regional benchmarking group and the proxy group that I relied on in setting the ROE. Mr. Adams benchmarks Public Service's performance on the basis of electric and natural gas distribution operating and administrative costs as well as reliability and customer satisfaction.

Q. Please summarize the results of that analysis.

A. Mr. Adams's analysis demonstrates that that Public Service's electric and gas operating costs are significantly lower than the peer group. In addition, Public Service's reliability and customer satisfaction ratings are consistently higher than the peer group.[43] The combination of these metrics indicates a well-managed company that is focused on controlling costs and providing high levels of reliability and customer satisfaction.

Q. Is the Company required to maintain a minimum level of reliability for its electric distribution system?

A. Yes. As discussed in the Panel Testimony of Public Service Witnesses Mr. Schmid and Mr. Fonseca, the Board sets annual reliability performance level targets for the electric utilities in New Jersey based on the average reliability level for an individual utility over the last five years. Given that Public Service's reliability ratings have been consistently higher than other electric utilities in New Jersey, Public Service's required reliability targets are also higher than the other electric utilities in New Jersey. As a result, absent the Commission's consideration of the Company's

[43] Reliability metrics measure the number and duration of interruptions. Therefore, lower metrics in these areas, as discussed by Mr. Adams, reflect stronger performance.

management performance in determining the authorized ROE in this proceeding, the Company would be held to higher reliability standard than its peers; however, the Company's ROE has historically been set at a level comparable to peers which are subject to lower reliability targets. It is therefore important that the Commission consider the Company's excellent management performance which has resulted in lower costs and higher reliability relative to its peers in determining the authorized ROE for Public Service.

Q. How does the benchmarking analysis affect your view of the authorized ROE for Public Service?

A. Based on the results of the benchmarking analysis, Public Service's electric and gas distribution customers have benefitted significantly from the Company's efficiency and cost containment efforts. In addition, while providing service at a lower cost than the peer group, Public Service's reliability metrics are stronger than the peer group average. Finally, the Company's customer service is strong and continually improving over the analytical period relied on by Mr. Adams. In my view, the benchmarking analysis demonstrates that Public Service's management performance has provided its customers with significantly lower cost and more reliable service than other similar electric and gas utilities and therefore supports an ROE that is above the mean of the proxy group results. Continued demonstrated management excellence that provides tangible benefits to customers such as lower overall costs and higher reliability metrics should be considered by the Board and supported through constructive regulation.

B. Capital Expenditures

Q. Please summarize the capital expenditure requirements for Public Service's electric and natural gas distribution operations.

A. The Company's current projections for 2023 through 2027 include approximately $17 billion in capital investments for the period.[44] Based on the Company's net utility plant of approximately $32.83 billion plus the Energy Efficiency regulatory asset of $0.4 billion as of December 31, 2022,[45] the projected capital expenditures are approximately 51.15 percent of Public Service's net utility investment balance as of December 31, 2022.

Q. How is the Company's risk profile affected by its substantial capital expenditures requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

---

[44] PSEG December 2023 Investor Update, approximate mid-point of PSE&G capital spending range 2023-2027 $16.0-$18.5B.

[45] From the PSEG 2022 10K. Net utility plant is from the PSE&G Consolidated Balance Sheet, page 68, Net Property, Plant and Equipment (December 31, 2022 balance is $32,830 million); the Energy Efficiency regulatory asset is from the Financial Statement Note 7, page 88 (Green Program Recovery Charges (GPRC), December 31, 2022 non-current asset balance is $447 million).

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[46]

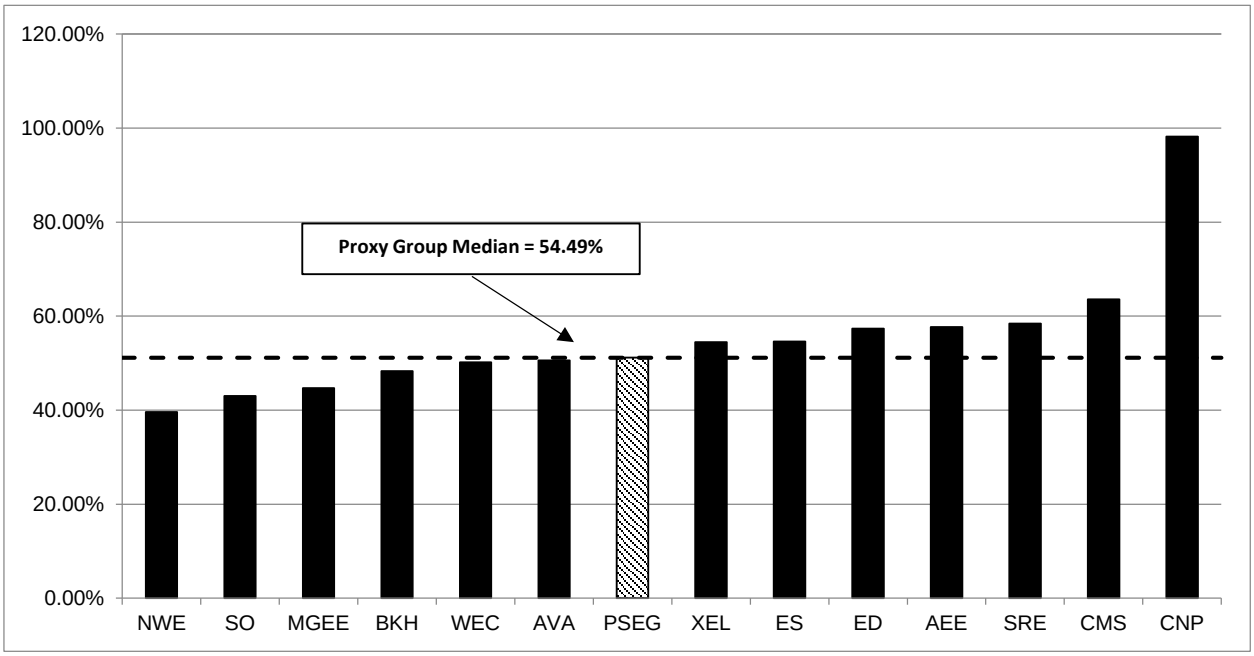
Therefore, to the extent that Public Service's rates do not permit the opportunity to earn an appropriate return and recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do Public Service's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in Schedule AEB-9, I calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024-2028 by its total net utility plant as of December 31, 2022. As shown in Schedule AEB-9 (see also Figure 11 below), the Company's ratio of capital expenditures as a percentage of net utility plant is 56.15 percent, which is similar to the median for the proxy group companies of 54.49 percent.

[46] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Figure 11: Comparison of Capital Expenditures



Q. Does Public Service have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. Partially. N.J.A.C. 14:3-2A, Infrastructure Investment Program ("IIP"), allows for a utility to obtain Board approval for the accelerated recovery of qualifying capital investments between rate cases. Public Service has periodic rate adjustments, on a lag, for a portion of its investments of specific Board-approved programs, for a portion of the Company's electric and natural gas operations. This allows Public Service to recover a portion of certain investments in the construction, installation and rehabilitation of certain non-revenue producing utility plant and facilities that meet safety, reliability or resiliency standards. For example, through the IIP, Public Service recovers a portion of the capital costs associated with the Company's Energy Strong II program, Infrastructure Advancement Program, and Gas System Modernization II Program ("GSMP"), albeit on a lag. In addition, the Company is able to recover capital costs associated with its Clean Energy Future – Energy Efficiency, other Energy Efficiency, and several solar

programs through the Green Programs Recovery Charge, which is available to both Public Service's electric and gas operations.

Q. Does the existence of these ratemaking mechanisms reduce the Company's level of risk vis a vis the companies in the proxy group?

A. No. A significant portion of the Company's future spending will require a base rate case filing for recovery. Further, the presence of these mechanisms is certainly a positive aspect of New Jersey regulation, but they have become quite commonplace in utility regulation. In fact, as shown in Schedule AEB-10 approximately 63 percent of the companies in the proxy group have implemented infrastructure replacement recovery mechanisms. In addition, approximately 48 percent of the proxy group companies set rates based on forecasted test years. Consequently the presence of the IIP mechanism and Green Programs charge, while positive regulatory mechanisms, do not reduce the Company's risk vis-à-vis that of the proxy group.

Q. What are your conclusions regarding the effect of Public Service's capital spending program on its risk profile and cost of capital?

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, similar to a number of the operating subsidiaries of the proxy group, Public Service does have capital tracking mechanisms to recover some of the Company's projected capital expenditures.

C. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory

decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors, on the other hand, require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength,

liquidity, and key financial metrics. Of these criteria, regulatory framework, and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[47]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[48] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[49]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[50] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of

---

47 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

48 Standard & Poor's Global Ratings. Ratings Direct. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 2.

49 *Id*.

50 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

rates), as well as the predictability and consistency of decision-making provided by that foundation."[51]

Q. Have you conducted any analysis of the risk associated with the regulatory framework in New Jersey relative to the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in New Jersey on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e., forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Schedule AEB-10 and are summarized as follows:

Test Year Convention: The Company uses partially forecast test year, which will be fully historical by the time a rate decision is issued in the current proceeding. However, approximately 44.30 percent of the utility operating subsidiaries of the companies in the proxy group use a fully forecasted test year, which will not be historical by the time of the rate decision.

Revenue Stabilization / Volumetric Risk: The Company does have partial protection against volumetric risk in New Jersey for its electric and natural gas operations. Public Service has a Conservation Incentive Program ("CIP") surcharge which allows for the recovery of lost sales revenue from the reduction in usage associated with energy efficiency programs and the recovery/refund of other deviations in sales due to, for example, variations in weather. As shown in Schedule AEB-10, approximately 57.0 percent of the operating companies held by the proxy group have some form of revenue stabilization either through straight fixed variable rate design, a formula rate plan, or other mechanisms.

[51] *Id*.

Capital Cost Recovery: As discussed above, the Company has capital tracking mechanisms (i.e., IIP mechanism and Green Programs charge) to recover a portion of capital investment costs between rate cases. This is consistent with the proxy group where 63.3 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

Q. Have you developed any additional analyses to evaluate the regulatory environment in New Jersey as compared to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have conducted two additional analyses to compare the regulatory framework of New Jersey to the jurisdictions in which the utility operating subsidiaries of the proxy group operate. Specifically, I considered two different rankings: (1) the Regulatory Research Associates ("RRA") ranking of regulatory jurisdictions, which is presented in Schedule AEB-11; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions, which is presented in Schedule AEB-12.

Q. Please explain how RRA evaluates the regulatory environment in each jurisdiction.

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, company and government outreach.

Q. Please explain how you used the RRA Rankings to compare the regulatory jurisdictions of the utility operating subsidiaries of the proxy group companies relative to the Company?

A. RRA assigns a ranking for each regulatory jurisdiction between "Above Average/1" to "Below Average/3," with nine total rankings between these categories. I applied a similar numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking ("1") and "Below Average/3" assigned the lowest ranking ("9"). As shown on Schedule AEB-11, the Company's jurisdictional ranking is "7" or "Below Average/1", which is below the proxy group's average numeric ranking of "4.75" from RRA, which is between "Average/1" and "Average/2."

Q. What information does RRA provide about how it determined a Below Average/1 rating for New Jersey regulation?

A. RRA states that from an investor perspective, the regulatory environment in New Jersey is restrictive and regulatory issues are highly politicized. Further, RRA notes that recently authorized ROEs are below prevailing industry averages and the use of a historical test year results and the inability to include construction work in progress in rate base impede the ability for companies to earn their authorized return. Additionally, RRA noted that New Jersey had a legislatively mandated moratorium on termination of service for non-payment of service during the pandemic that extended through March 15, 2022.[52] The deferrals resulting from this moratorium have not yet been resolved. RRA estimated the magnitude of the deferrals statewide at $710 million through the end of December 2020, however the legislatively mandated moratorium extended through March 15, 2022. The extensive lag and uncertainty of the recovery of these costs represents a significant risk factor from an investor perspective.

[52] Subsequent to RRA's report, the BPU extended the moratorium through March 15, 2023 for residential customers.

Q. How did you conduct your analysis of the S&P credit supportiveness?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Credit Supportive" to "Most Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate relative to the Company's regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking just discussed. Specifically, I assign a numerical ranking to each of S&P's categories, from Most Credit Supportive ("1") to Credit Supportive ("5"). As shown in Schedule AEB-12, the proxy group average ranking is 2.58, which would be classified between "Very Credit Supportive" and "Highly Credit Supportive," while Public Service's rank is lower at "More Credit Supportive" ("4"), which suggests that investors perceive regulation for the Company as below average relative to the proxy group.

Q. What is your conclusion regarding the regulatory framework in New Jersey as compared with the jurisdictions in which the proxy group companies operate?

A. The regulatory framework in which a regulated utility provides service is one of the most important considerations for debt and equity investors. Based on my analysis, I conclude that the regulatory risk for Public Service is higher than for the proxy group, which reflects that the New Jersey regulatory framework has somewhat greater risk than the jurisdictions in which the utility operating subsidiaries of the proxy group companies provide service. This conclusion is reflective of the proxy group generally having more timely cost recovery than the Company and the Company having an S&P credit supportive ranking and RRA ranking that is below the average for the proxy group.

VIII. CAPITAL STRUCTURE AND PROPOSED INTEREST COST RECONCILIATION DEFERRAL

A. Capital Structure

Q. Is the capital structure of a company an important consideration in the determination of the appropriate ROE?

A. Yes, it is. The equity ratio is the primary indicator of financial risk for a regulated utility such as Public Service. Assuming other factors equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q. What is Public Service's proposed capital structure?

A. As discussed in the Direct Testimony of Company Witness Mr. McFadden, the Company is proposing to establish a capital structure consisting of 55.50 percent common equity, 44.29 percent long-term debt, and 0.21 percent customer deposits.

Q. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A. Yes. I reviewed the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to

look to the average capital structure for the proxy groups to benchmark the equity ratios for the Company.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. Specifically, I calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent two years (i.e., eight quarters) for each of the companies in the proxy group at the operating subsidiary level. Schedule AEB-13 summarizes the actual capital structures of the operating subsidiaries. As shown, the two-year average equity ratios for the operating subsidiaries of the proxy group range from 47.21 percent to 66.21 percent. Public Service's proposed equity ratio of 55.5 percent is within the range established by the capital structures of the utility operating subsidiaries of the proxy group.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality.[53]

Fitch Ratings ("Fitch") also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated

[53] Moody's Investors Service, Outlook. "Outlook turns stable on low prices and credit-supportive regulation." September 7, 2023.

commodity prices, inflationary headwinds and rising interest costs," and that some offset in managing these headwinds include "higher authorized ROEs and the use of tools such as securitization of under-recovered fuel balances."[54]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[55]

The credit ratings agencies' continued concerns over the negative effects of inflation and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the industry as a whole, and Public Service in particular in the context of this proceeding.

Q. Why is this important in the consideration of the Company's capital structure?

A. The amount of debt in the capital structure decreases the financial flexibility of the company due to the fixed payment requirements of the debt service obligations. Therefore, in order to

[54] Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

[55] S&P Global Ratings. "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

maintain or improve cash flow metrics, the credit rating agencies have historically supported increasing the equity ratio, which reduces fixed payments and improves cash flow coverage ratios.

Q. What is your conclusion with regard to the Company's proposed capital structure?

A. Considering the actual capital structures of the proxy group operating companies, I believe that Public Service's proposed common equity ratio of 55.5 percent is reasonable. The proposed equity ratio is well within the range established by the capital structures of the utility operating subsidiaries of the proxy companies.

B. Interest Cost Reconciliation Deferral Mechanism

Q. Please explain the Company's proposed interest cost reconciliation deferral mechanism.

A. As discussed in the Direct Testimony of Public Service witness Mr. McFadden, the Company will need to refinance existing debt after the end of the test year; however, given that current interest rates *(i.e.,* 30-day average yield on the Moody's A-rated utility bond as of October 31,2023 was 6.20 percent)[56] exceed Public Service's embedded cost of long-term debt of 3.96 percent, the Company's interest expense will likely exceed that which can be recovered in rates during the first year that rates will go into effect. Therefore, the Company is proposing a new interest cost reconciliation deferral mechanism to defer the difference between the actual embedded cost of debt and the rate approved by the Board in this proceeding. The deferral mechanisms will only account for changes in the Company's embedded cost of debt associated with refinancing existing debt and will not reflect changes in the cost of debt associated with new issuances. The proposed deferral mechanism would be fully symmetric. Therefore, the deferral

[56] Source: Bloomberg Professional.

mechanism would ensure the Company recovers no more or less than its allowed interest expense and can be reevaluated in a future base rate case.

Q. Why is an interest cost reconciliation deferral mechanism appropriate?

A. There has been significant volatility in long-term interest rates over the past few years. For example, the 30-year Treasury yield reached a low of 0.99 percent in March 2020, but has since significantly increased as a result of the change in market conditions discussed in Section IV of my Direct Testimony. As noted above, the 30-day average yield on the 30-year Treasury bond as of October 31, 2023 was 4.84 percent, a more than four-fold increased from March 2020. The volatility in interest rates increases the likelihood that the Company's actual embedded cost of debt during the period that rates will be in effect will be either lower or higher than the embedded cost of debt approved by the Board in this proceeding. Further, the Company does not have any control over interest rates, which are set by the market and influenced by the monetary policy of the Federal Reserve. The deferral mechanism would ensure that customers only pay the actual cost of debt. Therefore, under this mechanism neither customers nor the Company is disadvantaged by changes in the market rate on the debt that is refinanced.

IX. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for the Company?

A. Based on the various quantitative analyses summarized in Figure 12 and the qualitative analyses presented in my Direct Testimony, a reasonable range of ROE results for Public Service is from 10.00 percent to 11.00 percent. Within that range, I believe that the Company's requested ROE of 10.40 percent is conservative considering the Company's excellent management performance, current conditions in capital markets including the high interest rates, and elevated

inflationary pressures, both of which increase the cost of capital as well as the relative business and financial risk of Public Service as compared to the proxy group.

Figure 12: Summary of Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.78%	9.69%	10.55%
90-Day Average	8.57%	9.47%	10.34%
180-Day Average	8.42%	9.32%	10.19%
	Median Low	Median	Median High
30-Day Average	8.87%	9.84%	10.44%
90-Day Average	8.53%	9.60%	10.27%
180-Day Average	8.31%	9.48%	10.05%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.66%	11.62%	11.55%
Bloomberg Beta	10.84%	10.75%	10.61%
Long-term Avg. Beta	10.47%	10.37%	10.20%
ECAPM			
Value Line Beta	11.87%	11.84%	11.79%
Bloomberg Beta	11.25%	11.18%	11.08%
Long-term Avg. Beta	10.98%	10.90%	10.77%
Bond Yield Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.74%	10.50%	10.13%

Q. What is your conclusion regarding Public Service's proposed capital structure?

A. My conclusion is that Public Service's proposed rate-making capital structure consisting of 55.50 percent common equity, 44.29 percent long-term debt, and customer deposits of 0.21 percent is reasonable as compared to the proxy group companies and should be used for setting rates in this case.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Ann E. Bulkley

PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas sectors, including rate of return, cost of equity, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of several hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	**Docket No. 23-_____-_____-RTS**	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-____	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

SUMMARY OF COE ANALYSES RESULTS

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.78%	9.69%	10.55%
90-Day Average	8.57%	9.47%	10.34%
180-Day Average	8.42%	9.32%	10.19%
Constant Growth Average	8.59%	9.49%	10.36%
	Median Low	Median	Median High
30-Day Average	8.87%	9.84%	10.44%
90-Day Average	8.53%	9.60%	10.27%
180-Day Average	8.31%	9.48%	10.05%
Constant Growth Average	8.57%	9.64%	10.25%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.66%	11.62%	11.55%
Bloomberg Beta	10.84%	10.75%	10.61%
Long-term Avg. Beta	10.47%	10.37%	10.20%
ECAPM			
Value Line Beta	11.87%	11.84%	11.79%
Bloomberg Beta	11.25%	11.18%	11.08%
Long-term Avg. Beta	10.98%	10.90%	10.77%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.74%	10.50%	10.13%

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Covered by More Than 1 Analyst	[4] Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	[5] % Regulated Operating Income > 70%	[6] % Regulated Gas Operating Income > 10%	[7] Announced Merger
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	100.00%	15.43%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	100.00%	26.15%	No
Black Hills Corporation	BKH	Yes	BBB+	Yes	Yes	94.70%	50.09%	No
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	Yes	101.54%	45.49%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	99.71%	34.20%	No
Consolidated Edison, Inc.	ED	Yes	A-	Yes	Yes	90.49%	27.63%	No
Eversource Energy	ES	Yes	A-	Yes	Yes	92.38%	14.65%	No
MGE Energy, Inc.	MGEE	Yes	AA-	Yes	Yes	72.55%	26.84%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	99.75%	15.51%	No
Sempra Energy	SRE	Yes	BBB+	Yes	Yes	74.47%	37.14%	No
Southern Company	SO	Yes	BBB+	Yes	Yes	94.89%	20.78%	No
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	Yes	99.53%	46.01%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	100.00%	13.53%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5]-[6] Source: Form 10-K's for 2022, 2021, and 2020
[7] Source: S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF -- PSEG PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	$2.52	$76.34	3.30%	3.41%	6.50%	6.20%	6.60%	6.43%	9.60%	9.84%	10.01%
Avista Corporation	AVA	$1.84	$32.31	5.69%	5.87%	6.00%	6.30%	6.30%	6.20%	11.86%	12.07%	12.17%
Black Hills Corporation	BKH	$2.50	$50.10	4.99%	5.08%	3.00%	5.40%	2.20%	3.53%	7.24%	8.61%	10.52%
CenterPoint Energy, Inc	CNP	$0.76	$27.31	2.78%	2.88%	6.50%	negative	7.50%	7.00%	9.37%	9.88%	10.39%
CMS Energy Corporation	CMS	$1.95	$53.82	3.62%	3.74%	6.50%	5.87%	7.50%	6.62%	9.60%	10.37%	11.26%
Consolidated Edison, Inc.	ED	$3.24	$87.47	3.70%	3.79%	6.00%	6.12%	2.00%	4.71%	5.74%	8.50%	9.94%
Eversource Energy	ES	$2.70	$56.56	4.77%	4.90%	6.50%	4.00%	5.00%	5.17%	8.87%	10.06%	11.43%
MGE Energy, Inc	MGEE	$1.71	$70.97	2.41%	2.48%	6.50%	5.40%	5.30%	5.73%	7.77%	8.21%	8.99%
NorthWestern Corporation	NWE	$2.56	$48.46	5.28%	5.39%	3.50%	4.08%	5.20%	4.26%	8.87%	9.65%	10.62%
Sempra Energy	SRE	$2.38	$69.16	3.44%	3.53%	6.50%	4.14%	5.00%	5.21%	7.65%	8.74%	10.05%
Southern Company	SO	$2.80	$66.50	4.21%	4.33%	6.50%	7.10%	4.00%	5.87%	8.29%	10.20%	11.46%
Wisconsin Energy Corporation	WEC	$3.12	$81.91	3.81%	3.92%	6.00%	5.70%	5.80%	5.83%	9.62%	9.75%	9.92%
Xcel Energy Inc.	XEL	$2.08	$58.29	3.57%	3.68%	6.00%	6.75%	6.30%	6.35%	9.68%	10.03%	10.44%
Mean				3.97%	4.08%	5.85%	5.59%	5.28%	5.61%	8.78%	9.69%	10.55%
Median				3.70%	3.79%	6.50%	5.79%	5.30%	5.83%	8.87%	9.84%	10.44%

Notes:
[1] Source: Bloomberg Professiona
[2] Source: Bloomberg Professional, equals 30-day average as of October 31, 202
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8]
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7

90-DAY CONSTANT GROWTH DCF -- PSEG PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	$2.52	$79.74	3.16%	3.26%	6.50%	6.20%	6.60%	6.43%	9.46%	9.70%	9.86%
Avista Corporation	AVA	$1.84	$34.80	5.29%	5.45%	6.00%	6.30%	6.30%	6.20%	11.45%	11.65%	11.75%
Black Hills Corporation	BKH	$2.50	$54.84	4.56%	4.64%	3.00%	5.40%	2.20%	3.53%	6.81%	8.17%	10.08%
CenterPoint Energy, Inc	CNP	$0.76	$28.39	2.68%	2.77%	6.50%	negative	7.50%	7.00%	9.26%	9.77%	10.28%
CMS Energy Corporation	CMS	$1.95	$56.74	3.44%	3.55%	6.50%	5.87%	7.50%	6.62%	9.41%	10.17%	11.07%
Consolidated Edison, Inc.	ED	$3.24	$89.75	3.61%	3.70%	6.00%	6.12%	2.00%	4.71%	5.65%	8.40%	9.84%
Eversource Energy	ES	$2.70	$63.56	4.25%	4.36%	6.50%	4.00%	5.00%	5.17%	8.33%	9.52%	10.89%
MGE Energy, Inc	MGEE	$1.71	$74.51	2.30%	2.36%	6.50%	5.40%	5.30%	5.73%	7.66%	8.09%	8.87%
NorthWestern Corporation	NWE	$2.56	$51.80	4.94%	5.05%	3.50%	4.08%	5.20%	4.26%	8.53%	9.31%	10.27%
Sempra Energy	SRE	$2.38	$70.89	3.36%	3.44%	6.50%	4.14%	5.00%	5.21%	7.57%	8.66%	9.97%
Southern Company	SO	$2.80	$68.33	4.10%	4.22%	6.50%	7.10%	4.00%	5.87%	8.18%	10.08%	11.34%
Wisconsin Energy Corporation	WEC	$3.12	$85.32	3.66%	3.76%	6.00%	5.70%	5.80%	5.83%	9.46%	9.60%	9.77%
Xcel Energy Inc.	XEL	$2.08	$59.42	3.50%	3.61%	6.00%	6.75%	6.30%	6.35%	9.61%	9.96%	10.37%
Mean				3.76%	3.86%	5.85%	5.59%	5.28%	5.61%	8.57%	9.47%	10.34%
Median				3.61%	3.70%	6.50%	5.79%	5.30%	5.83%	8.53%	9.60%	10.27%

Notes:
[1] Source: Bloomberg Professiona
[2] Source: Bloomberg Professional, equals 90-day average as of October 31, 202
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8]
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7

180-DAY CONSTANT GROWTH DCF -- PSEG PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth	[6] Yahoo! Finance EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
Ameren Corporation	AEE	$2.52	$81.85	3.08%	3.18%	6.50%	6.20%	6.60%	6.43%	9.37%	9.61%	9.78%
Avista Corporation	AVA	$1.84	$37.99	4.84%	4.99%	6.00%	6.30%	6.30%	6.20%	10.99%	11.19%	11.30%
Black Hills Corporation	BKH	$2.50	$58.37	4.28%	4.36%	3.00%	5.40%	2.20%	3.53%	6.53%	7.89%	9.80%
CenterPoint Energy, Inc	CNP	$0.76	$28.64	2.65%	2.75%	6.50%	negative	7.50%	7.00%	9.24%	9.75%	10.25%
CMS Energy Corporation	CMS	$1.95	$58.15	3.35%	3.46%	6.50%	5.87%	7.50%	6.62%	9.32%	10.09%	10.98%
Consolidated Edison, Inc.	ED	$3.24	$91.57	3.54%	3.62%	6.00%	6.12%	2.00%	4.71%	5.57%	8.33%	9.77%
Eversource Energy	ES	$2.70	$68.77	3.93%	4.03%	6.50%	4.00%	5.00%	5.17%	8.00%	9.19%	10.55%
MGE Energy, Inc	MGEE	$1.71	$74.51	2.29%	2.36%	6.50%	5.40%	5.30%	5.73%	7.66%	8.09%	8.87%
NorthWestern Corporation	NWE	$2.56	$54.16	4.73%	4.83%	3.50%	4.08%	5.20%	4.26%	8.31%	9.09%	10.05%
Sempra Energy	SRE	$2.38	$72.30	3.29%	3.38%	6.50%	4.14%	5.00%	5.21%	7.50%	8.59%	9.90%
Southern Company	SO	$2.80	$68.45	4.09%	4.21%	6.50%	7.10%	4.00%	5.87%	8.17%	10.08%	11.34%
Wisconsin Energy Corporation	WEC	$3.12	$88.14	3.54%	3.64%	6.00%	5.70%	5.80%	5.83%	9.34%	9.48%	9.65%
Xcel Energy Inc.	XEL	$2.08	$62.43	3.33%	3.44%	6.00%	6.75%	6.30%	6.35%	9.43%	9.79%	10.19%
Mean				3.61%	3.71%	5.85%	5.59%	5.28%	5.61%	8.42%	9.32%	10.19%
Median				3.54%	3.62%	6.50%	5.79%	5.30%	5.83%	8.31%	9.48%	10.05%

Notes:
[1] Source: Bloomberg Professiona
[2] Source: Bloomberg Professional, equals 180-day average as of October 31, 202
[3] Equals [1] / [2
[4] Equals [3] x (1 + 0.50 x [8]
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7]
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
Ameren Corporation	AEE	4.84%	0.85	12.49%	7.64%	11.34%	11.63%
Avista Corporation	AVA	4.84%	0.90	12.49%	7.64%	11.72%	11.91%
Black Hills Corporation	BKH	4.84%	1.00	12.49%	7.64%	12.49%	12.49%
CenterPoint Energy, Inc.	CNP	4.84%	1.10	12.49%	7.64%	13.25%	13.06%
CMS Energy Corporation	CMS	4.84%	0.80	12.49%	7.64%	10.96%	11.34%
Consolidated Edison, Inc.	ED	4.84%	0.80	12.49%	7.64%	10.96%	11.34%
Eversource Energy	ES	4.84%	0.90	12.49%	7.64%	11.72%	11.91%
MGE Energy, Inc.	MGEE	4.84%	0.75	12.49%	7.64%	10.58%	11.05%
NorthWestern Corporation	NWE	4.84%	0.95	12.49%	7.64%	12.10%	12.20%
Sempra Energy	SRE	4.84%	1.00	12.49%	7.64%	12.49%	12.49%
Southern Company	SO	4.84%	0.90	12.49%	7.64%	11.72%	11.91%
Wisconsin Energy Corporation	WEC	4.84%	0.80	12.49%	7.64%	10.96%	11.34%
Xcel Energy Inc.	XEL	4.84%	0.85	12.49%	7.64%	11.34%	11.63%
Mean						11.66%	11.87%
Median						11.72%	11.91%

Notes:
[1] Source: Bloomberg Professional, as of October 31, 2023
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
Ameren Corporation	AEE	4.44%	0.85	12.49%	8.05%	11.28%	11.58%
Avista Corporation	AVA	4.44%	0.90	12.49%	8.05%	11.68%	11.88%
Black Hills Corporation	BKH	4.44%	1.00	12.49%	8.05%	12.49%	12.49%
CenterPoint Energy, Inc.	CNP	4.44%	1.10	12.49%	8.05%	13.29%	13.09%
CMS Energy Corporation	CMS	4.44%	0.80	12.49%	8.05%	10.88%	11.28%
Consolidated Edison, Inc.	ED	4.44%	0.80	12.49%	8.05%	10.88%	11.28%
Eversource Energy	ES	4.44%	0.90	12.49%	8.05%	11.68%	11.88%
MGE Energy, Inc.	MGEE	4.44%	0.75	12.49%	8.05%	10.48%	10.98%
NorthWestern Corporation	NWE	4.44%	0.95	12.49%	8.05%	12.08%	12.19%
Sempra Energy	SRE	4.44%	1.00	12.49%	8.05%	12.49%	12.49%
Southern Company	SO	4.44%	0.90	12.49%	8.05%	11.68%	11.88%
Wisconsin Energy Corporation	WEC	4.44%	0.80	12.49%	8.05%	10.88%	11.28%
Xcel Energy Inc.	XEL	4.44%	0.85	12.49%	8.05%	11.28%	11.58%
Mean						11.62%	11.84%
Median						11.68%	11.88%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 11, November 1, 2023, at 2
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	3.80%	0.85	12.49%	8.69%	11.18%	11.51%
Avista Corporation	AVA	3.80%	0.90	12.49%	8.69%	11.62%	11.84%
Black Hills Corporation	BKH	3.80%	1.00	12.49%	8.69%	12.49%	12.49%
CenterPoint Energy, Inc.	CNP	3.80%	1.10	12.49%	8.69%	13.36%	13.14%
CMS Energy Corporation	CMS	3.80%	0.80	12.49%	8.69%	10.75%	11.18%
Consolidated Edison, Inc.	ED	3.80%	0.80	12.49%	8.69%	10.75%	11.18%
Eversource Energy	ES	3.80%	0.90	12.49%	8.69%	11.62%	11.84%
MGE Energy, Inc.	MGEE	3.80%	0.75	12.49%	8.69%	10.32%	10.86%
NorthWestern Corporation	NWE	3.80%	0.95	12.49%	8.69%	12.05%	12.16%
Sempra Energy	SRE	3.80%	1.00	12.49%	8.69%	12.49%	12.49%
Southern Company	SO	3.80%	0.90	12.49%	8.69%	11.62%	11.84%
Wisconsin Energy Corporation	WEC	3.80%	0.80	12.49%	8.69%	10.75%	11.18%
Xcel Energy Inc.	XEL	3.80%	0.85	12.49%	8.69%	11.18%	11.51%
Mean						11.55%	11.79%
Median						11.62%	11.84%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	4.84%	0.75	12.49%	7.64%	10.59%	11.06%
Avista Corporation	AVA	4.84%	0.75	12.49%	7.64%	10.59%	11.07%
Black Hills Corporation	BKH	4.84%	0.90	12.49%	7.64%	11.72%	11.91%
CenterPoint Energy, Inc.	CNP	4.84%	0.98	12.49%	7.64%	12.35%	12.38%
CMS Energy Corporation	CMS	4.84%	0.75	12.49%	7.64%	10.55%	11.03%
Consolidated Edison, Inc.	ED	4.84%	0.63	12.49%	7.64%	9.69%	10.39%
Eversource Energy	ES	4.84%	0.80	12.49%	7.64%	10.98%	11.36%
MGE Energy, Inc.	MGEE	4.84%	0.68	12.49%	7.64%	10.04%	10.65%
NorthWestern Corporation	NWE	4.84%	0.86	12.49%	7.64%	11.40%	11.67%
Sempra Energy	SRE	4.84%	0.84	12.49%	7.64%	11.30%	11.60%
Southern Company	SO	4.84%	0.77	12.49%	7.64%	10.75%	11.19%
Wisconsin Energy Corporation	WEC	4.84%	0.73	12.49%	7.64%	10.46%	10.97%
Xcel Energy Inc.	XEL	4.84%	0.74	12.49%	7.64%	10.48%	10.98%
Mean						10.84%	11.25%
Median						10.59%	11.07%

Notes:
[1] Source: Bloomberg Professional, as of October 31, 2023
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	4.44%	0.75	12.49%	8.05%	10.49%	10.99%
Avista Corporation	AVA	4.44%	0.75	12.49%	8.05%	10.49%	10.99%
Black Hills Corporation	BKH	4.44%	0.90	12.49%	8.05%	11.68%	11.88%
CenterPoint Energy, Inc.	CNP	4.44%	0.98	12.49%	8.05%	12.34%	12.38%
CMS Energy Corporation	CMS	4.44%	0.75	12.49%	8.05%	10.45%	10.96%
Consolidated Edison, Inc.	ED	4.44%	0.63	12.49%	8.05%	9.54%	10.28%
Eversource Energy	ES	4.44%	0.80	12.49%	8.05%	10.90%	11.30%
MGE Energy, Inc.	MGEE	4.44%	0.68	12.49%	8.05%	9.91%	10.55%
NorthWestern Corporation	NWE	4.44%	0.86	12.49%	8.05%	11.34%	11.63%
Sempra Energy	SRE	4.44%	0.84	12.49%	8.05%	11.24%	11.55%
Southern Company	SO	4.44%	0.77	12.49%	8.05%	10.66%	11.12%
Wisconsin Energy Corporation	WEC	4.44%	0.73	12.49%	8.05%	10.35%	10.89%
Xcel Energy Inc.	XEL	4.44%	0.74	12.49%	8.05%	10.37%	10.90%
Mean						10.75%	11.18%
Median						10.49%	10.99%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 11, November 1, 2023, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	3.80%	0.75	12.49%	8.69%	10.33%	10.87%
Avista Corporation	AVA	3.80%	0.75	12.49%	8.69%	10.33%	10.87%
Black Hills Corporation	BKH	3.80%	0.90	12.49%	8.69%	11.61%	11.83%
CenterPoint Energy, Inc.	CNP	3.80%	0.98	12.49%	8.69%	12.33%	12.37%
CMS Energy Corporation	CMS	3.80%	0.75	12.49%	8.69%	10.28%	10.83%
Consolidated Edison, Inc.	ED	3.80%	0.63	12.49%	8.69%	9.30%	10.10%
Eversource Energy	ES	3.80%	0.80	12.49%	8.69%	10.77%	11.20%
MGE Energy, Inc.	MGEE	3.80%	0.68	12.49%	8.69%	9.70%	10.40%
NorthWestern Corporation	NWE	3.80%	0.86	12.49%	8.69%	11.25%	11.56%
Sempra Energy	SRE	3.80%	0.84	12.49%	8.69%	11.14%	11.48%
Southern Company	SO	3.80%	0.77	12.49%	8.69%	10.52%	11.01%
Wisconsin Energy Corporation	WEC	3.80%	0.73	12.49%	8.69%	10.18%	10.76%
Xcel Energy Inc.	XEL	3.80%	0.74	12.49%	8.69%	10.20%	10.77%
Mean						10.61%	11.08%
Median						10.33%	10.87%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	4.84%	0.73	12.49%	7.64%	10.39%	10.91%
Avista Corporation	AVA	4.84%	0.79	12.49%	7.64%	10.84%	11.25%
Black Hills Corporation	BKH	4.84%	0.89	12.49%	7.64%	11.65%	11.86%
CenterPoint Energy, Inc.	CNP	4.84%	0.92	12.49%	7.64%	11.88%	12.03%
CMS Energy Corporation	CMS	4.84%	0.69	12.49%	7.64%	10.12%	10.71%
Consolidated Edison, Inc.	ED	4.84%	0.60	12.49%	7.64%	9.39%	10.17%
Eversource Energy	ES	4.84%	0.74	12.49%	7.64%	10.53%	11.02%
MGE Energy, Inc.	MGEE	4.84%	0.69	12.49%	7.64%	10.08%	10.68%
NorthWestern Corporation	NWE	4.84%	0.75	12.49%	7.64%	10.54%	11.03%
Sempra Energy	SRE	4.84%	0.83	12.49%	7.64%	11.15%	11.48%
Southern Company	SO	4.84%	0.66	12.49%	7.64%	9.85%	10.51%
Wisconsin Energy Corporation	WEC	4.84%	0.66	12.49%	7.64%	9.89%	10.54%
Xcel Energy Inc.	XEL	4.84%	0.66	12.49%	7.64%	9.85%	10.51%
Mean						10.47%	10.98%
Median						10.39%	10.91%

Notes:
[1] Source: Bloomberg Professional, as of October 31, 2023
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	4.44%	0.73	12.49%	8.05%	10.27%	10.83%
Avista Corporation	AVA	4.44%	0.79	12.49%	8.05%	10.76%	11.19%
Black Hills Corporation	BKH	4.44%	0.89	12.49%	8.05%	11.60%	11.82%
CenterPoint Energy, Inc.	CNP	4.44%	0.92	12.49%	8.05%	11.84%	12.00%
CMS Energy Corporation	CMS	4.44%	0.69	12.49%	8.05%	9.99%	10.62%
Consolidated Edison, Inc.	ED	4.44%	0.60	12.49%	8.05%	9.23%	10.04%
Eversource Energy	ES	4.44%	0.74	12.49%	8.05%	10.42%	10.94%
MGE Energy, Inc.	MGEE	4.44%	0.69	12.49%	8.05%	9.95%	10.59%
NorthWestern Corporation	NWE	4.44%	0.75	12.49%	8.05%	10.43%	10.95%
Sempra Energy	SRE	4.44%	0.83	12.49%	8.05%	11.08%	11.43%
Southern Company	SO	4.44%	0.66	12.49%	8.05%	9.71%	10.40%
Wisconsin Energy Corporation	WEC	4.44%	0.66	12.49%	8.05%	9.75%	10.43%
Xcel Energy Inc.	XEL	4.44%	0.66	12.49%	8.05%	9.71%	10.40%
Mean						10.37%	10.90%
Median						10.27%	10.83%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 11, November 1, 2023, at 2
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
Ameren Corporation	AEE	3.80%	0.73	12.49%	8.69%	10.10%	10.70%
Avista Corporation	AVA	3.80%	0.79	12.49%	8.69%	10.62%	11.09%
Black Hills Corporation	BKH	3.80%	0.89	12.49%	8.69%	11.53%	11.77%
CenterPoint Energy, Inc.	CNP	3.80%	0.92	12.49%	8.69%	11.79%	11.97%
CMS Energy Corporation	CMS	3.80%	0.69	12.49%	8.69%	9.79%	10.47%
Consolidated Edison, Inc.	ED	3.80%	0.60	12.49%	8.69%	8.97%	9.85%
Eversource Energy	ES	3.80%	0.74	12.49%	8.69%	10.26%	10.82%
MGE Energy, Inc.	MGEE	3.80%	0.69	12.49%	8.69%	9.75%	10.43%
NorthWestern Corporation	NWE	3.80%	0.75	12.49%	8.69%	10.27%	10.83%
Sempra Energy	SRE	3.80%	0.83	12.49%	8.69%	10.97%	11.35%
Southern Company	SO	3.80%	0.66	12.49%	8.69%	9.49%	10.24%
Wisconsin Energy Corporation	WEC	3.80%	0.66	12.49%	8.69%	9.53%	10.27%
Xcel Energy Inc.	XEL	3.80%	0.66	12.49%	8.69%	9.49%	10.24%
Mean						10.20%	10.77%
Median						10.10%	10.70%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA - 2013 - 2022

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] Average
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.73
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.79
Black Hills Corporation	BKH	0.90	0.90	0.90	0.90	0.90	0.75	0.70	1.00	1.00	0.95	0.89
CenterPoint Energy, Inc.	CNP	0.80	0.75	0.85	0.85	0.90	0.85	0.80	1.15	1.15	1.10	0.92
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.69
Consolidated Edison, Inc.	ED	0.60	0.60	0.60	0.55	0.50	0.40	0.45	0.75	0.75	0.75	0.60
Eversource Energy	ES			0.75	0.70	0.65	0.60	0.55	0.90	0.90	0.90	0.74
MGE Energy, Inc.	MGEE	0.65	0.70	0.75	0.70	0.75	0.60	0.55	0.70	0.75	0.70	0.69
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.75
Sempra Energy	SRE	0.75	0.75	0.80	0.80	0.80	0.75	0.70	1.00	0.95	0.95	0.83
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.66
Wisconsin Energy Corporation	WEC	0.65	0.65	0.70	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.66
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.66
Mean		0.71	0.71	0.74	0.69	0.70	0.60	0.58	0.89	0.89	0.87	0.74

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.88%
[2] Estimated Weighted Average Long-Term Growth Rate	10.51%
[3] S&P 500 Estimated Required Market Return	12.49%

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	324.36	90.24	29,270.43	0.11%	5.54%	0.01%	11.00%	0.01%
American Express Co	AXP	728.75	146.03	106,418.78	0.40%	1.64%	0.01%	13.94%	0.06%
Verizon Communications Inc	VZ	4,204.10	35.13	147,690.10		7.57%			
Broadcom Inc	AVGO	412.74	841.37	347,263.69	1.31%	2.19%	0.03%	12.40%	0.16%
Boeing Co/The	BA	604.98	186.82	113,021.80					
Caterpillar Inc	CAT	510.14	226.05	115,317.83	0.44%	2.30%	0.01%	20.00%	0.09%
JPMorgan Chase & Co	JPM	2,906.09	139.06	404,120.18	1.52%	3.02%	0.05%	1.00%	0.02%
Chevron Corp	CVX	1,867.25	145.73	272,113.61	1.03%	4.14%	0.04%	7.27%	0.07%
Coca-Cola Co/The	KO	4,323.41	56.49	244,229.66	0.92%	3.26%	0.03%	7.02%	0.06%
AbbVie Inc	ABBV	1,765.05	141.18	249,189.34	0.94%	4.39%	0.04%	6.50%	0.06%
Walt Disney Co/The	DIS	1,829.78	81.59	149,291.67				22.27%	
FleetCor Technologies Inc	FLT	73.96	225.17	16,652.90	0.06%			12.40%	0.01%
Extra Space Storage Inc	EXR	211.28	103.59	21,886.18	0.08%	2.36%	0.00%	0.61%	0.00%
Exxon Mobil Corp	XOM	3,962.92	105.85	419,474.87	1.58%	3.59%	0.06%	16.80%	0.27%
Phillips 66	PSX	445.29	114.07	50,794.00	0.19%	3.68%	0.01%	15.21%	0.03%
General Electric Co	GE	1,088.39	108.63	118,231.37	0.45%	0.29%	0.00%	7.00%	0.03%
HP Inc	HPQ	988.27	26.33	26,021.12	0.10%	3.99%	0.00%	0.50%	0.00%
Home Depot Inc/The	HD	1,000.07	284.69	284,708.79	1.07%	2.94%	0.03%	3.32%	0.04%
Monolithic Power Systems Inc	MPWR	47.91	441.74	21,164.21	0.08%	0.91%	0.00%	8.00%	0.01%
International Business Machines Corp	IBM	913.12	144.64	132,073.53	0.50%	4.59%	0.02%	2.77%	0.01%
Johnson & Johnson	JNJ	2,407.28	148.34	357,095.77	1.35%	3.21%	0.04%	3.86%	0.05%
Lululemon Athletica Inc	LULU	121.43	393.48	47,778.31	0.18%			16.00%	0.03%
McDonald's Corp	MCD	728.76	262.17	191,059.80	0.72%	2.55%	0.02%	9.67%	0.07%
Merck & Co Inc	MRK	2,537.52	102.70	260,603.41	0.98%	2.84%	0.03%	8.51%	0.08%
3M Co	MMM	552.32	90.95	50,233.23	0.19%	6.60%	0.01%	4.00%	0.01%
American Water Works Co Inc	AWK	194.67	117.65	22,902.81	0.09%	2.41%	0.00%	8.00%	0.01%
Bank of America Corp	BAC	7,913.73	26.34	208,447.70		3.64%			
Pfizer Inc	PFE	5,645.96	30.56	172,540.54		5.37%		50.40%	
Procter & Gamble Co/The	PG	2,356.89	150.03	353,603.61	1.33%	2.51%	0.03%	7.51%	0.10%
AT&T Inc	T	7,150.02	15.40	110,110.31	0.42%	7.21%	0.03%	2.44%	0.01%
Travelers Cos Inc/The	TRV	228.40	167.44	38,243.13	0.14%	2.39%	0.00%	15.33%	0.02%
RTX Corp	RTX	1,437.90	81.39	117,030.76	0.44%	2.90%	0.01%	8.61%	0.04%
Analog Devices Inc	ADI	498.31	157.33	78,399.74	0.30%	2.19%	0.01%	6.50%	0.02%
Walmart Inc	WMT	2,691.56	163.41	439,828.47	1.66%	1.40%	0.02%	8.00%	0.13%
Cisco Systems Inc	CSCO	4,050.54	52.13	211,154.75	0.80%	2.99%	0.02%	7.50%	0.06%
Intel Corp	INTC	4,216.00	36.50	153,884.00		1.37%		-1.82%	
General Motors Co	GM	1,369.48	28.20	38,619.36	0.15%	1.28%	0.00%	0.36%	0.00%
Microsoft Corp	MSFT	7,432.26	338.11	2,512,922.10	9.48%	0.89%	0.08%	15.72%	1.49%
Dollar General Corp	DG	219.48	119.04	26,126.42		1.98%		-2.50%	
Cigna Group/The	CI	295.98	309.20	91,517.02	0.35%	1.59%	0.01%	9.80%	0.03%
Kinder Morgan Inc	KMI	2,222.77	16.20	36,008.94	0.14%	6.98%	0.01%	2.00%	0.00%
Citigroup Inc	C	1,913.90	39.49	75,579.91		5.37%		-9.70%	
American International Group Inc	AIG	711.90	61.31	43,646.59	0.16%	2.35%	0.00%	10.00%	0.02%
Altria Group Inc	MO	1,768.65	40.17	71,046.55	0.27%	9.76%	0.03%	4.50%	0.01%
HCA Healthcare Inc	HCA	267.66	226.14	60,528.86	0.23%	1.06%	0.00%	7.56%	0.02%
International Paper Co	IP	346.02	33.73	11,671.15		5.48%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1,282.87	15.38	19,730.46	0.07%	3.12%	0.00%	3.03%	0.00%
Abbott Laboratories	ABT	1,735.36	94.55	164,078.10	0.62%	2.16%	0.01%	3.27%	0.02%
Aflac Inc	AFL	594.06	78.11	46,402.18	0.18%	2.15%	0.00%	5.98%	0.01%
Air Products and Chemicals Inc	APD	222.15	282.44	62,743.76	0.24%	2.48%	0.01%	10.86%	0.03%
Royal Caribbean Cruises Ltd	RCL	256.24	84.73	21,710.79					
Hess Corp	HES	307.06	144.40	44,339.61	0.17%	1.21%	0.00%	13.00%	0.02%
Archer-Daniels-Midland Co	ADM	533.38	71.57	38,174.08		2.52%		-7.07%	
Automatic Data Processing Inc	ADP	411.70	218.22	89,841.17	0.34%	2.29%	0.01%	16.00%	0.05%
Verisk Analytics Inc	VRSK	145.03	227.36	32,973.34	0.12%	0.60%	0.00%	10.52%	0.01%
AutoZone Inc	AZO	17.63	2,477.13	43,681.71	0.16%			13.72%	0.02%
Avery Dennison Corp	AVY	80.53	174.07	14,018.03	0.05%	1.86%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.55	79.58	10,866.73				30.50%	
MSCI Inc	MSCI	79.09	471.55	37,295.36	0.14%	1.17%	0.00%	14.41%	0.02%
Ball Corp	BALL	315.06	48.15	15,170.09	0.06%	1.66%	0.00%	10.30%	0.01%
Axon Enterprise Inc	AXON	74.76	204.49	15,287.67					
Ceridian HCM Holding Inc	CDAY	155.61	64.01	9,960.79					
Carrier Global Corp	CARR	839.05	47.66	39,988.98	0.15%	1.55%	0.00%	10.80%	0.02%
Bank of New York Mellon Corp/The	BK	769.07	42.50	32,685.60	0.12%	3.95%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	409.26	77.21	31,598.89	0.12%	1.76%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	506.41	32.43	16,422.71	0.06%	3.58%	0.00%	0.33%	0.00%
Becton Dickinson & Co	BDX	290.11	252.78	73,333.75	0.28%	1.44%	0.00%	9.20%	0.03%
Berkshire Hathaway Inc	BRK/B	1,308.07	341.33	446,483.53					
Best Buy Co Inc	BBY	217.64	66.82	14,542.57	0.05%	5.51%	0.00%	3.21%	0.00%
Boston Scientific Corp	BSX	1,464.22	51.19	74,953.58	0.28%			12.10%	0.03%
Bristol-Myers Squibb Co	BMY	2,034.76	51.53	104,851.08	0.40%	4.42%	0.02%	2.22%	0.01%
Brown-Forman Corp	BF/B	310.14	56.16	17,417.24	0.07%	1.46%	0.00%	7.04%	0.00%
Coterra Energy Inc	CTRA	755.05	27.50	20,763.77		2.91%		23.02%	
Campbell Soup Co	CPB	297.62	40.41	12,026.91	0.05%	3.66%	0.00%	3.17%	0.00%
Hilton Worldwide Holdings Inc	HLT	256.44	151.53	38,858.35	0.15%	0.40%	0.00%	17.09%	0.03%
Carnival Corp	CCL	1,119.45	11.46	12,828.84					
Qorvo Inc	QRVO	97.91	87.42	8,559.29	0.03%			2.83%	0.00%
UDR Inc	UDR	328.93	31.81	10,463.20	0.04%	5.28%	0.00%	6.08%	0.00%
Clorox Co/The	CLX	124.00	117.70	14,594.92	0.06%	4.08%	0.00%	14.82%	0.01%
Paycom Software Inc	PAYC	60.47	244.97	14,812.60		0.61%		21.43%	

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
CMS Energy Corp	CMS	291.76	53.86	15,713.24	0.06%	3.62%	0.00%	7.33%	0.00%
Colgate-Palmolive Co	CL	823.37	75.12	61,851.70	0.23%	2.56%	0.01%	7.61%	0.02%
EPAM Systems Inc	EPAM	57.96	217.57	12,610.57	0.05%			4.70%	0.00%
Comerica Inc	CMA	131.87	39.40	5,195.80	0.02%	7.21%	0.00%	10.63%	0.00%
Conagra Brands Inc	CAG	477.97	27.01	12,909.92	0.05%	5.18%	0.00%	0.84%	0.00%
Airbnb Inc	ABNB	426.36	118.29	50,434.01	0.19%			18.84%	0.04%
Consolidated Edison Inc	ED	344.92	87.79	30,280.88	0.11%	3.69%	0.00%	4.88%	0.01%
Corning Inc	GLW	853.18	26.76	22,830.96	0.09%	4.19%	0.00%	1.57%	0.00%
Cummins Inc	CMI	141.65	216.30	30,638.25	0.12%	3.11%	0.00%	11.27%	0.01%
Caesars Entertainment Inc	CZR	215.71	39.89	8,604.71					
Danaher Corp	DHR	738.93	192.02	141,888.76		0.56%		-5.34%	
Target Corp	TGT	461.61	110.79	51,141.22		3.97%		-0.10%	
Deere & Co	DE	288.00	365.36	105,224.05	0.40%	1.48%	0.01%	16.67%	0.07%
Dominion Energy Inc	D	836.77	40.32	33,738.69		6.62%		-3.05%	
Dover Corp	DOV	139.89	129.95	18,178.71	0.07%	1.57%	0.00%	10.00%	0.01%
Alliant Energy Corp	LNT	252.72	48.79	12,330.16	0.05%	3.71%	0.00%	6.26%	0.00%
Steel Dynamics Inc	STLD	165.64	106.51	17,642.74		1.60%		-16.12%	
Duke Energy Corp	DUK	771.00	88.89	68,534.19	0.26%	4.61%	0.01%	6.06%	0.02%
Regency Centers Corp	REG	171.00	60.26	10,304.64	0.04%	4.31%	0.00%	4.98%	0.00%
Eaton Corp PLC	ETN	399.30	207.91	83,018.46	0.31%	1.65%	0.01%	15.00%	0.05%
Ecolab Inc	ECL	285.03	167.74	47,811.60	0.18%	1.26%	0.00%	15.40%	0.03%
Revvity Inc	RVTY	124.14	82.85	10,284.58		0.34%		-26.69%	
Emerson Electric Co	EMR	571.50	88.97	50,846.36	0.19%	2.34%	0.00%	16.70%	0.03%
EOG Resources Inc	EOG	582.26	126.25	73,510.45	0.28%	2.61%	0.01%	11.33%	0.03%
Aon PLC	AON	200.22	309.40	61,946.83	0.23%	0.80%	0.00%	11.58%	0.03%
Entergy Corp	ETR	211.46	95.59	20,213.08	0.08%	4.73%	0.00%	6.03%	0.00%
Equifax Inc	EFX	123.22	169.57	20,893.91	0.08%	0.92%	0.00%	12.33%	0.01%
EQT Corp	EQT	411.33	42.38	17,432.25		1.49%		22.52%	
IQVIA Holdings Inc	IQV	183.12	180.83	33,113.95	0.12%			13.12%	0.02%
Gartner Inc	IT	78.83	332.04	26,173.05	0.10%			7.22%	0.01%
FedEx Corp	FDX	251.42	240.10	60,365.94	0.23%	2.10%	0.00%	14.50%	0.03%
FMC Corp	FMC	124.73	53.20	6,635.85		4.36%		-4.00%	
Brown & Brown Inc	BRO	284.60	69.42	19,756.79	0.07%	0.75%	0.00%	11.00%	0.01%
Ford Motor Co	F	3,932.10	9.75	38,337.99		6.15%		-2.52%	
NextEra Energy Inc	NEE	2,023.71	58.30	117,982.53	0.45%	3.21%	0.01%	8.76%	0.04%
Franklin Resources Inc	BEN	498.98	22.79	11,371.71		5.27%		-9.00%	
Garmin Ltd	GRMN	191.45	102.53	19,629.57	0.07%	2.85%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1,433.64	33.78	48,428.22		1.78%		-13.95%	
Dexcom Inc	DXCM	386.37	88.83	34,321.60				30.59%	
General Dynamics Corp	GD	272.90	241.31	65,852.78	0.25%	2.19%	0.01%	10.40%	0.03%
General Mills Inc	GIS	581.28	65.24	37,922.64	0.14%	3.62%	0.01%	8.00%	0.01%
Genuine Parts Co	GPC	140.20	128.86	18,065.79	0.07%	2.95%	0.00%	9.49%	0.01%
Atmos Energy Corp	ATO	148.46	107.66	15,983.42	0.06%	2.75%	0.00%	7.25%	0.00%
WW Grainger Inc	GWW	49.63	729.83	36,224.38		1.02%			
Halliburton Co	HAL	895.05	39.34	35,211.35		1.63%		24.14%	
L3Harris Technologies Inc	LHX	189.54	179.41	34,005.37	0.13%	2.54%	0.00%	3.50%	0.00%
Healthpeak Properties Inc	PEAK	547.07	15.55	8,507.00		7.72%			
Insulet Corp	PODD	69.82	132.57	9,256.17				39.24%	
Catalent Inc	CTLT	180.27	34.39	6,199.55					
Fortive Corp	FTV	351.43	65.28	22,941.61	0.09%	0.43%	0.00%	8.68%	0.01%
Hershey Co/The	HSY	149.89	187.35	28,080.95	0.11%	2.54%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	413.80	28.05	11,607.20		3.57%			
Hormel Foods Corp	HRL	546.48	32.55	17,787.96	0.07%	3.38%	0.00%	2.39%	0.00%
Arthur J Gallagher & Co	AJG	215.90	235.49	50,842.29	0.19%	0.93%	0.00%	14.49%	0.03%
Mondelez International Inc	MDLZ	1,360.42	66.21	90,073.28	0.34%	2.57%	0.01%	7.97%	0.03%
CenterPoint Energy Inc	CNP	629.43	26.88	16,919.13	0.06%	2.98%	0.00%	8.02%	0.01%
Humana Inc	HUM	123.91	523.69	64,888.86	0.24%	0.68%	0.00%	12.32%	0.03%
Willis Towers Watson PLC	WTW	103.26	235.89	24,358.00	0.09%	1.42%	0.00%	11.19%	0.01%
Illinois Tool Works Inc	ITW	300.89	224.12	67,434.57	0.25%	2.50%	0.01%	3.91%	0.01%
CDW Corp/DE	CDW	134.05	200.40	26,863.22	0.10%	1.18%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	228.40	190.31	43,466.42	0.16%	1.58%	0.00%	11.86%	0.02%
Interpublic Group of Cos Inc/The	IPG	383.00	28.40	10,877.31	0.04%	4.37%	0.00%	5.71%	0.00%
International Flavors & Fragrances Inc	IFF	255.25	68.35	17,446.54		4.74%		-10.08%	
Generac Holdings Inc	GNRC	62.24	84.07	5,232.77	0.02%			4.50%	0.00%
NXP Semiconductors NV	NXPI	257.80	172.43	44,452.80		2.35%		20.50%	
Kellanova	K	342.35	50.47	17,278.25	0.07%	4.44%	0.00%	1.94%	0.00%
Broadridge Financial Solutions Inc	BR	117.62	170.64	20,070.85		1.88%			
Kimberly-Clark Corp	KMB	337.94	119.64	40,431.26	0.15%	3.95%	0.01%	9.64%	0.01%
Kimco Realty Corp	KIM	619.89	17.94	11,120.86	0.04%	5.35%	0.00%	3.47%	0.00%
Oracle Corp	ORCL	2,739.38	103.40	283,251.48	1.07%	1.55%	0.02%	14.45%	0.15%
Kroger Co/The	KR	719.32	45.37	32,635.37	0.12%	2.56%	0.00%	4.55%	0.01%
Lennar Corp	LEN	250.15	106.68	26,686.22	0.10%	1.41%	0.00%	1.00%	0.00%
Eli Lilly & Co	LLY	949.30	553.93	525,842.98		0.82%		23.26%	
Bath & Body Works Inc	BBWI	227.38	29.65	6,741.85	0.03%	2.70%	0.00%	11.38%	0.00%
Charter Communications Inc	CHTR	147.92	402.80	59,582.18	0.22%			13.16%	0.03%
Loews Corp	L	223.25	64.01	14,290.30		0.39%			
Lowe's Cos Inc	LOW	577.12	190.57	109,980.81		2.31%		20.59%	
Hubbell Inc	HUBB	53.63	270.10	14,485.73		1.81%			
IDEX Corp	IEX	75.63	191.41	14,475.57	0.05%	1.34%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.07	189.65	93,511.10	0.35%	1.50%	0.01%	10.85%	0.04%
Masco Corp	MAS	224.50	52.09	11,694.26	0.04%	2.19%	0.00%	4.36%	0.00%
S&P Global Inc	SPGI	318.20	349.31	111,150.44	0.42%	1.03%	0.00%	13.54%	0.06%
Medtronic PLC	MDT	1,330.53	70.56	93,882.48	0.35%	3.91%	0.01%	3.17%	0.01%
Viatris Inc	VTRS	1,199.53	8.90	10,675.83		5.39%		-2.38%	
CVS Health Corp	CVS	1,284.40	69.01	88,636.37	0.33%	3.51%	0.01%	7.13%	0.02%
DuPont de Nemours Inc	DD	459.06	72.88	33,456.37	0.13%	1.98%	0.00%	12.18%	0.02%
Micron Technology Inc	MU	1,098.03	66.87	73,425.53		0.69%		-11.00%	
Motorola Solutions Inc	MSI	167.02	278.46	46,508.39	0.18%	1.26%	0.00%	12.22%	0.02%
Cboe Global Markets Inc	CBOE	105.52	163.89	17,293.18	0.07%	1.34%	0.00%	7.62%	0.00%
Laboratory Corp of America Holdings	LH	84.90	199.73	16,957.08		1.44%		-19.90%	
Newmont Corp	NEM	794.80	37.47	29,781.16	0.11%	4.27%	0.00%	12.20%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
NIKE Inc	NKE	1,224.01	102.77	125,791.82	0.47%	1.32%	0.01%	16.07%	0.08%
NiSource Inc	NI	413.26	25.16	10,397.50	0.04%	3.97%	0.00%	7.00%	0.00%
Norfolk Southern Corp	NSC	226.14	189.44	42,838.25	0.16%	2.85%	0.00%	0.73%	0.00%
Principal Financial Group Inc	PFG	241.72	67.68	16,359.27	0.06%	3.96%	0.00%	8.76%	0.01%
Eversource Energy	ES	349.09	53.79	18,777.34	0.07%	5.02%	0.00%	5.21%	0.00%
Northrop Grumman Corp	NOC	150.79	471.43	71,088.34	0.27%	1.59%	0.00%	2.53%	0.01%
Wells Fargo & Co	WFC	3,631.64	39.42	143,154.16	0.54%	3.55%	0.02%	13.41%	0.07%
Nucor Corp	NUE	248.72	147.79	36,758.62		1.38%		-11.10%	
Occidental Petroleum Corp	OXY	884.68	61.81	54,682.19		1.16%		-2.25%	
Omnicom Group Inc	OMC	197.93	74.91	14,827.24	0.06%	3.74%	0.00%	6.36%	0.00%
ONEOK Inc	OKE	582.47	65.20	37,977.24	0.14%	5.86%	0.01%	7.43%	0.01%
Raymond James Financial Inc	RJF	208.80	95.44	19,927.87		1.76%			
PG&E Corp	PCG	2,133.51	16.30	34,776.18	0.13%			9.63%	0.01%
Parker-Hannifin Corp	PH	128.51	368.91	47,408.62	0.18%	1.60%	0.00%	14.56%	0.03%
Rollins Inc	ROL	484.04	37.61	18,204.67	0.07%	1.60%	0.00%	14.86%	0.01%
PPL Corp	PPL	737.09	24.57	18,110.28	0.07%	3.91%	0.00%	5.20%	0.00%
ConocoPhillips	COP	1,197.49	118.80	142,261.93		0.51%		0.00%	
PulteGroup Inc	PHM	215.60	73.59	15,865.64	0.06%	0.87%	0.00%	2.04%	0.00%
Pinnacle West Capital Corp	PNW	113.31	74.18	8,405.48	0.03%	4.75%	0.00%	5.90%	0.00%
PNC Financial Services Group Inc/The	PNC	398.34	114.47	45,598.09	0.17%	5.42%	0.01%	12.87%	0.02%
PPG Industries Inc	PPG	235.80	122.77	28,949.17	0.11%	2.12%	0.00%	11.24%	0.01%
Progressive Corp/The	PGR	585.04	158.09	92,489.13		0.25%		38.38%	
Veralto Corp	VLTO	246.31	69.00	16,995.25					
Public Service Enterprise Group Inc	PEG	499.11	61.65	30,770.19	0.12%	3.70%	0.00%	6.23%	0.01%
Robert Half Inc	RHI	105.90	74.77	7,917.77	0.03%	2.57%	0.00%	1.26%	0.00%
Cooper Cos Inc/The	COO	49.52	311.75	15,439.11	0.06%	0.02%	0.00%	7.54%	0.00%
Edison International	EIX	383.29	63.06	24,170.20	0.09%	4.68%	0.00%	4.80%	0.00%
Schlumberger NV	SLB	1,423.42	55.66	79,227.61		1.80%		33.41%	
Charles Schwab Corp/The	SCHW	1,770.22	52.04	92,122.25	0.35%	1.92%	0.01%	3.60%	0.01%
Sherwin-Williams Co/The	SHW	255.97	238.21	60,973.66	0.23%	1.02%	0.00%	7.95%	0.02%
West Pharmaceutical Services Inc	WST	73.99	318.29	23,550.28	0.09%	0.25%	0.00%	5.80%	0.01%
J M Smucker Co/The	SJM	102.14	113.84	11,627.85	0.04%	3.72%	0.00%	6.09%	0.00%
Snap-on Inc	SNA	52.78	257.94	13,614.07	0.05%	2.51%	0.00%	4.85%	0.00%
AMETEK Inc	AME	230.80	140.77	32,489.58	0.12%	0.71%	0.00%	8.16%	0.01%
Southern Co/The	SO	1,091.52	67.30	73,458.96	0.28%	4.16%	0.01%	5.05%	0.01%
Truist Financial Corp	TFC	1,333.67	28.36	37,822.82	0.14%	7.33%	0.01%	16.00%	0.02%
Southwest Airlines Co	LUV	596.12	22.23	13,251.64	0.05%	3.24%	0.00%	10.15%	0.01%
W R Berkley Corp	WRB	258.04	67.42	17,397.33	0.07%	0.65%	0.00%	13.00%	0.01%
Stanley Black & Decker Inc	SWK	153.31	85.05	13,039.10	0.05%	3.81%	0.00%	9.00%	0.00%
Public Storage	PSA	175.83	238.71	41,972.14	0.16%	5.03%	0.01%	4.44%	0.01%
Arista Networks Inc	ANET	311.10	200.37	62,335.11				20.66%	
Sysco Corp	SYY	504.23	66.49	33,525.99	0.13%	3.01%	0.00%	13.00%	0.02%
Corteva Inc	CTVA	709.52	48.14	34,156.10	0.13%	1.33%	0.00%	17.67%	0.02%
Texas Instruments Inc	TXN	908.20	142.01	128,974.05	0.49%	3.66%	0.02%	10.00%	0.05%
Textron Inc	TXT	196.01	76.00	14,896.38	0.06%	0.11%	0.00%	11.73%	0.01%
Thermo Fisher Scientific Inc	TMO	385.95	444.77	171,658.98		0.31%		-5.00%	
TJX Cos Inc/The	TJX	1,144.08	88.07	100,759.21	0.38%	1.51%	0.01%	10.00%	0.04%
Globe Life Inc	GL	94.82	116.36	11,033.26		0.77%			
Johnson Controls International plc	JCI	680.32	49.02	33,349.29	0.13%	3.02%	0.00%	13.36%	0.02%
Ulta Beauty Inc	ULTA	49.23	381.31	18,771.51	0.07%			6.54%	0.00%
Union Pacific Corp	UNP	609.60	207.61	126,558.43	0.48%	2.50%	0.01%	6.50%	0.03%
Keysight Technologies Inc	KEYS	177.58	122.05	21,673.03	0.08%			2.52%	0.00%
UnitedHealth Group Inc	UNH	926.31	535.56	496,091.91	1.87%	1.40%	0.03%	12.79%	0.24%
Blackstone Inc	BX	718.44	92.35	66,348.21	0.25%	3.47%	0.01%	7.63%	0.02%
Marathon Oil Corp	MRO	605.69	27.31	16,541.31		1.61%		-10.00%	
Bio-Rad Laboratories Inc	BIO	24.06	275.28	6,622.96	0.02%			4.00%	0.00%
Ventas Inc	VTR	402.38	42.46	17,084.97	0.06%	4.24%	0.00%	7.81%	0.01%
VF Corp	VFC	388.87	14.73	5,728.03	0.02%	2.44%	0.00%	7.80%	0.00%
Vulcan Materials Co	VMC	132.87	196.49	26,108.22		0.88%		23.22%	
Weyerhaeuser Co	WY	730.00	28.69	20,943.73		2.65%			
Whirlpool Corp	WHR	54.85	104.56	5,735.43		6.69%		-2.33%	
Williams Cos Inc/The	WMB	1,216.42	34.40	41,844.88	0.16%	5.20%	0.01%	3.50%	0.01%
Constellation Energy Corp	CEG	321.59	112.92	36,314.17		1.00%		26.26%	
WEC Energy Group Inc	WEC	315.44	81.39	25,673.25	0.10%	3.83%	0.00%	6.47%	0.01%
Adobe Inc	ADBE	455.30	532.06	242,246.92	0.91%			17.33%	0.16%
AES Corp/The	AES	669.63	14.90	9,977.47	0.04%	4.45%	0.00%	6.37%	0.00%
Amgen Inc	AMGN	535.18	255.70	136,845.01	0.52%	3.33%	0.02%	5.33%	0.03%
Apple Inc	AAPL	15,634.23	170.77	2,669,857.80	10.07%	0.56%	0.06%	9.05%	0.91%
Autodesk Inc	ADSK	213.76	197.63	42,246.18	0.16%			13.86%	0.02%
Cintas Corp	CTAS	101.85	507.12	51,652.20	0.19%	1.06%	0.00%	11.86%	0.02%
Comcast Corp	CMCSA	4,015.64	41.29	165,805.57	0.63%	2.81%	0.02%	9.26%	0.06%
Molson Coors Beverage Co	TAP	200.96	57.77	11,609.46	0.04%	2.84%	0.00%	8.01%	0.00%
KLA Corp	KLAC	135.93	469.70	63,847.26	0.24%	1.11%	0.00%	9.93%	0.02%
Marriott International Inc/MD	MAR	298.24	188.56	56,236.13	0.21%	1.10%	0.00%	17.06%	0.04%
Fiserv Inc	FI	600.19	113.75	68,271.16	0.26%			14.08%	0.04%
McCormick & Co Inc/MD	MKC	251.29	63.90	16,057.49	0.06%	2.44%	0.00%	7.01%	0.00%
PACCAR Inc	PCAR	523.10	82.53	43,171.44	0.16%	1.31%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	442.74	551.43	244,139.78	0.92%	0.74%	0.01%	13.06%	0.12%
Stryker Corp	SYK	379.78	270.22	102,623.61	0.39%	1.11%	0.00%	7.26%	0.03%
Tyson Foods Inc	TSN	285.55	46.35	13,235.24		4.14%		-24.28%	
Lamb Weston Holdings Inc	LW	144.93	89.52	12,974.39	0.05%	1.25%	0.00%	13.32%	0.01%
Applied Materials Inc	AMAT	836.53	132.35	110,715.27	0.42%	0.97%	0.00%	3.73%	0.02%
American Airlines Group Inc	AAL	653.54	11.15	7,286.98				54.64%	
Cardinal Health Inc	CAH	246.35	91.00	22,418.21		2.20%			
Cincinnati Financial Corp	CINF	156.91	99.67	15,639.02	0.06%	3.01%	0.00%	18.21%	0.01%
Paramount Global	PARA	610.40	10.88	6,641.14		1.84%		-22.86%	
DR Horton Inc	DHI	338.30	104.40	35,318.21		0.96%		-8.43%	
Electronic Arts Inc	EA	270.91	123.79	33,536.20	0.13%	0.61%	0.00%	9.26%	0.01%
Fair Isaac Corp	FICO	24.86	845.87	21,025.79					
Expeditors International of Washington Inc	EXPD	147.90	109.25	16,157.75		1.26%			
Fastenal Co	FAST	571.41	58.34	33,336.23		2.40%			

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
M&T Bank Corp	MTB	165.97	112.75	18,713.12	0.07%	4.61%	0.00%	11.59%	0.01%
Xcel Energy Inc	XEL	551.82	59.27	32,706.13	0.12%	3.51%	0.00%	5.95%	0.01%
Fifth Third Bancorp	FITB	680.99	23.71	16,146.27		5.90%		25.00%	
Gilead Sciences Inc	GILD	1,246.01	78.54	97,861.94	0.37%	3.82%	0.01%	2.15%	0.01%
Hasbro Inc	HAS	138.74	45.15	6,264.16		6.20%		-3.49%	
Huntington Bancshares Inc/OH	HBAN	1,448.08	9.65	13,973.92		6.42%		-7.69%	
Welltower Inc	WELL	532.27	83.61	44,502.93	0.17%	2.92%	0.00%	10.19%	0.02%
Biogen Inc	BIIB	144.82	237.54	34,401.26	0.13%			0.05%	0.00%
Northern Trust Corp	NTRS	207.04	65.91	13,645.74	0.05%	4.55%	0.00%	13.00%	0.01%
Packaging Corp of America	PKG	89.92	153.05	13,761.49	0.05%	3.27%	0.00%	3.00%	0.00%
Paychex Inc	PAYX	361.23	111.05	40,114.81	0.15%	3.21%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1,116.00	108.99	121,632.84		2.94%		-1.35%	
Ross Stores Inc	ROST	338.63	115.97	39,271.15	0.15%	1.16%	0.00%	10.00%	0.01%
IDEXX Laboratories Inc	IDXX	83.01	399.47	33,160.80	0.13%			17.57%	0.02%
Starbucks Corp	SBUX	1,145.40	92.24	105,651.70		2.47%		20.53%	
KeyCorp	KEY	936.16	10.22	9,567.57	0.04%	8.02%	0.00%	7.08%	0.00%
Fox Corp	FOXA	253.68	30.39	7,709.46	0.03%	1.71%	0.00%	6.24%	0.00%
Fox Corp	FOX	235.58	27.91	6,575.07	0.02%	1.86%	0.00%	6.24%	0.00%
State Street Corp	STT	308.58	64.63	19,943.78	0.08%	4.27%	0.00%	6.92%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	425.42	13.60	5,785.77					
US Bancorp	USB	1,556.97	31.88	49,636.04	0.19%	6.02%	0.01%	7.50%	0.01%
A O Smith Corp	AOS	122.83	69.76	8,568.48		1.83%			
Gen Digital Inc	GEN	639.44	16.66	10,653.05		3.00%			
T Rowe Price Group Inc	TROW	223.47	90.50	20,224.04		5.39%		-3.90%	
Waste Management Inc	WM	402.78	164.33	66,188.02	0.25%	1.70%	0.00%	10.05%	0.03%
Constellation Brands Inc	STZ	183.66	233.26	42,841.23	0.16%	1.53%	0.00%	9.75%	0.02%
DENTSPLY SIRONA Inc	XRAY	211.72	30.41	6,438.28	0.02%	1.84%	0.00%	9.78%	0.00%
Zions Bancorp NA	ZION	148.15	30.85	4,570.30		5.32%		-9.73%	
Alaska Air Group Inc	ALK	127.12	31.63	4,020.81	0.02%			3.56%	0.00%
Invesco Ltd	IVZ	449.55	12.97	5,830.72		6.17%		-4.35%	
Intuit Inc	INTU	280.26	494.95	138,714.19	0.52%	0.73%	0.00%	18.84%	0.10%
Morgan Stanley	MS	1,656.97	70.82	117,346.40	0.44%	4.80%	0.02%	3.64%	0.02%
Microchip Technology Inc	MCHP	544.33	71.29	38,805.57	0.15%	2.30%	0.00%	12.06%	0.02%
Chubb Ltd	CB	407.98	214.62	87,561.53	0.33%	1.60%	0.01%	15.50%	0.05%
Hologic Inc	HOLX	244.94	66.17	16,207.81				-16.00%	
Citizens Financial Group Inc	CFG	466.22	23.43	10,923.58		7.17%		-10.63%	
O'Reilly Automotive Inc	ORLY	59.62	930.44	55,473.76	0.21%			11.39%	0.02%
Allstate Corp/The	ALL	261.57	128.13	33,515.48		2.78%		-3.00%	
Equity Residential	EQR	379.03	55.33	20,971.84	0.08%	4.79%	0.00%	5.17%	0.00%
BorgWarner Inc	BWA	235.06	36.90	8,673.82	0.03%	1.19%	0.00%	5.16%	0.00%
Keurig Dr Pepper Inc	KDP	1,398.34	30.33	42,411.53	0.16%	2.84%	0.00%	6.85%	0.01%
Host Hotels & Resorts Inc	HST	711.61	15.48	11,015.65		4.65%			
Incyte Corp	INCY	224.11	53.93	12,086.20				36.36%	
Simon Property Group Inc	SPG	326.25	109.89	35,851.28	0.14%	6.92%	0.01%	1.71%	0.00%
Eastman Chemical Co	EMN	118.56	74.73	8,860.29	0.03%	4.23%	0.00%	4.75%	0.00%
AvalonBay Communities Inc	AVB	142.02	165.74	23,537.73	0.09%	3.98%	0.00%	10.62%	0.01%
Prudential Financial Inc	PRU	363.00	91.44	33,192.72	0.13%	5.47%	0.01%	10.60%	0.01%
United Parcel Service Inc	UPS	723.28	141.25	102,162.74	0.39%	4.59%	0.02%	1.64%	0.01%
Walgreens Boots Alliance Inc	WBA	863.92	21.08	18,211.33	0.07%	9.11%	0.01%	0.25%	0.00%
STERIS PLC	STE	98.78	209.98	20,742.03		0.99%			
McKesson Corp	MCK	134.90	455.36	61,428.97	0.23%	0.54%	0.00%	10.03%	0.02%
Lockheed Martin Corp	LMT	248.10	454.64	112,795.73	0.43%	2.77%	0.01%	7.04%	0.03%
Cencora Inc	COR	202.18	185.15	37,432.70	0.14%	1.05%	0.00%	9.44%	0.01%
Capital One Financial Corp	COF	381.00	101.29	38,591.49		2.37%		-6.32%	
Waters Corp	WAT	59.10	238.53	14,097.84	0.05%			5.37%	0.00%
Nordson Corp	NDSN	57.01	212.59	12,120.61		1.28%			
Dollar Tree Inc	DLTR	220.01	111.09	24,440.47	0.09%			7.37%	0.01%
Darden Restaurants Inc	DRI	120.32	145.53	17,509.44	0.07%	3.60%	0.00%	10.45%	0.01%
Evergy Inc	EVRG	229.58	49.14	11,281.71	0.04%	4.99%	0.00%	4.82%	0.00%
Match Group Inc	MTCH	278.09	34.60	9,621.81				48.68%	
Domino's Pizza Inc	DPZ	34.88	338.99	11,824.31	0.04%	1.43%	0.00%	13.97%	0.01%
NVR Inc	NVR	3.21	5,412.62	17,374.51				-4.57%	
NetApp Inc	NTAP	208.79	72.78	15,195.81	0.06%	2.75%	0.00%	7.40%	0.00%
Old Dominion Freight Line Inc	ODFL	109.27	376.66	41,156.88	0.16%	0.42%	0.00%	5.83%	0.01%
DaVita Inc	DVA	91.30	77.23	7,051.10	0.03%			15.78%	0.00%
Hartford Financial Services Group Inc/The	HIG	300.77	73.45	22,091.56	0.08%	2.56%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.85	59.07	17,239.70	0.07%	4.40%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	232.30	128.87	29,936.11		2.05%		22.00%	
Cadence Design Systems Inc	CDNS	272.06	239.85	65,254.07	0.25%			18.56%	0.05%
Tyler Technologies Inc	TYL	42.08	372.90	15,690.89					
Universal Health Services Inc	UHS	62.14	125.89	7,822.80	0.03%	0.64%	0.00%	9.41%	0.00%
Skyworks Solutions Inc	SWKS	159.39	86.74	13,825.75	0.05%	3.14%	0.00%	4.99%	0.00%
Quest Diagnostics Inc	DGX	112.44	130.10	14,627.79		2.18%		-1.27%	
Rockwell Automation Inc	ROK	114.86	262.81	30,186.36	0.11%	1.90%	0.00%	15.47%	0.02%
Kraft Heinz Co/The	KHC	1,228.30	31.46	38,642.16	0.15%	5.09%	0.01%	3.92%	0.01%
American Tower Corp	AMT	466.17	178.19	83,065.94	0.31%	3.64%	0.01%	13.67%	0.04%
Regeneron Pharmaceuticals Inc	REGN	106.74	779.89	83,246.24	0.31%			3.33%	0.01%
Amazon.com Inc	AMZN	10,334.03	133.09	1,375,356.19				52.33%	
Jack Henry & Associates Inc	JKHY	72.80	140.99	10,264.21	0.04%	1.48%	0.00%	7.52%	0.00%
Ralph Lauren Corp	RL	40.39	112.53	4,544.86	0.02%	2.67%	0.00%	10.82%	0.00%
Boston Properties Inc	BXP	156.87	53.57	8,403.26	0.03%	7.32%	0.00%	3.79%	0.00%
Amphenol Corp	APH	598.31	80.55	48,193.87	0.18%	1.09%	0.00%	4.04%	0.01%
Howmet Aerospace Inc	HWM	412.21	44.10	18,178.37	0.07%	0.45%	0.00%	19.27%	0.01%
Pioneer Natural Resources Co	PXD	233.31	239.00	55,760.85		3.08%		-3.00%	
Valero Energy Corp	VLO	340.45	127.00	43,237.53		3.21%		35.66%	
Synopsys Inc	SNPS	152.08	469.44	71,394.31	0.27%			16.27%	0.04%
Etsy Inc	ETSY	123.01	62.30	7,663.77	0.03%			7.02%	0.00%
CH Robinson Worldwide Inc	CHRW	116.44	81.83	9,528.20	0.04%	2.98%	0.00%	5.00%	0.00%
Accenture PLC	ACN	664.79	297.09	197,501.57	0.75%	1.74%	0.01%	10.00%	0.07%
TransDigm Group Inc	TDG	55.18	828.09	45,696.49				26.65%	
Yum! Brands Inc	YUM	280.21	120.86	33,866.30	0.13%	2.00%	0.00%	12.91%	0.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Prologis Inc	PLD	923.86	100.75	93,079.10	0.35%	3.45%	0.01%	8.04%	0.03%
FirstEnergy Corp	FE	573.82	35.60	20,427.81		4.61%		-0.83%	
VeriSign Inc	VRSN	102.10	199.66	20,385.29	0.08%			11.50%	0.01%
Quanta Services Inc	PWR	145.20	167.12	24,265.66	0.09%	0.19%	0.00%	8.00%	0.01%
Henry Schein Inc	HSIC	130.59	64.98	8,485.41	0.03%			5.16%	0.00%
Ameren Corp	AEE	262.48	75.71	19,871.98	0.07%	3.33%	0.00%	6.21%	0.00%
ANSYS Inc	ANSS	86.79	278.26	24,150.46	0.09%			11.14%	0.01%
FactSet Research Systems Inc	FDS	37.99	431.89	16,406.64	0.06%	0.91%	0.00%	10.45%	0.01%
NVIDIA Corp	NVDA	2,470.00	407.80	1,007,266.00		0.04%		56.84%	
Sealed Air Corp	SEE	144.41	30.79	4,446.38	0.02%	2.60%	0.00%	0.93%	0.00%
Cognizant Technology Solutions Corp	CTSH	505.04	64.47	32,559.99	0.12%	1.80%	0.00%	12.00%	0.01%
Intuitive Surgical Inc	ISRG	352.07	262.22	92,320.32	0.35%			11.57%	0.04%
Take-Two Interactive Software Inc	TTWO	169.83	133.75	22,714.90				54.11%	
Republic Services Inc	RSG	314.64	148.49	46,720.45	0.18%	1.44%	0.00%	9.93%	0.02%
eBay Inc	EBAY	532.16	39.23	20,876.52	0.08%	2.55%	0.00%	9.50%	0.01%
Goldman Sachs Group Inc/The	GS	329.67	303.61	100,091.41	0.38%	3.62%	0.01%	7.71%	0.03%
SBA Communications Corp	SBAC	108.38	208.63	22,611.95	0.09%	1.63%	0.00%	8.00%	0.01%
Sempra	SRE	629.31	70.03	44,070.37	0.17%	3.40%	0.01%	5.49%	0.01%
Moody's Corp	MCO	183.00	308.00	56,364.00	0.21%	1.00%	0.00%	14.08%	0.03%
ON Semiconductor Corp	ON	430.70	62.64	26,978.92	0.10%			5.81%	0.01%
Booking Holdings Inc	BKNG	35.69	2,789.56	99,564.98	0.38%			17.50%	0.07%
F5 Inc	FFIV	59.21	151.59	8,975.19	0.03%			5.45%	0.00%
Akamai Technologies Inc	AKAM	151.71	103.33	15,676.50	0.06%			10.72%	0.01%
Charles River Laboratories International Inc	CRL	51.27	168.36	8,631.99	0.03%			11.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.91	213.75	8,102.19		1.35%			
Devon Energy Corp	DVN	640.70	46.57	29,837.40		4.21%		-4.00%	
Bio-Techne Corp	TECH	158.24	54.63	8,644.65	0.03%	0.59%	0.00%	5.00%	0.00%
Alphabet Inc	GOOGL	5,918.00	124.08	734,305.44	2.77%			16.65%	0.46%
Teleflex Inc	TFX	46.99	184.75	8,681.77	0.03%	0.74%	0.00%	7.03%	0.00%
Bunge Ltd	6369743D	145.29	105.98	15,397.62		2.50%			
Netflix Inc	NFLX	437.68	411.69	180,188.48				30.96%	
Allegion plc	ALLE	87.79	98.36	8,634.83	0.03%	1.83%	0.00%	5.93%	0.00%
Agilent Technologies Inc	A	292.59	103.37	30,244.72	0.11%	0.87%	0.00%	11.00%	0.01%
Warner Bros Discovery Inc	WBD	2,437.38	9.94	24,227.60				71.32%	
Elevance Health Inc	ELV	234.96	450.09	105,752.70	0.40%	1.32%	0.01%	10.85%	0.04%
Trimble Inc	TRMB	248.32	47.13	11,703.42					
CME Group Inc	CME	359.75	213.46	76,791.38	0.29%	2.06%	0.01%	11.10%	0.03%
Juniper Networks Inc	JNPR	318.87	26.92	8,583.93	0.03%	3.27%	0.00%	7.96%	0.00%
BlackRock Inc	BLK	149.30	612.28	91,415.24	0.34%	3.27%	0.01%	6.72%	0.02%
DTE Energy Co	DTE	206.11	96.38	19,864.79	0.07%	3.95%	0.00%	6.00%	0.00%
Nasdaq Inc	NDAQ	491.32	49.60	24,369.27	0.09%	1.77%	0.00%	2.68%	0.00%
Celanese Corp	CE	108.85	114.51	12,464.64	0.05%	2.45%	0.00%	3.27%	0.00%
Philip Morris International Inc	PM	1,552.41	89.16	138,412.52	0.52%	5.83%	0.03%	9.19%	0.05%
Salesforce Inc	CRM	973.00	200.83	195,407.59				21.67%	
Ingersoll Rand Inc	IR	404.40	60.68	24,538.93		0.13%			
Roper Technologies Inc	ROP	106.71	488.57	52,135.79		0.56%		-1.00%	
Huntington Ingalls Industries Inc	HII	39.87	219.82	8,763.78		2.26%		40.00%	
MetLife Inc	MET	752.02	60.01	45,128.84	0.17%	3.47%	0.01%	12.89%	0.02%
Tapestry Inc	TPR	227.44	27.56	6,268.22	0.02%	5.08%	0.00%	15.00%	0.00%
CSX Corp	CSX	1,976.13	29.85	58,987.51	0.22%	1.47%	0.00%	6.39%	0.01%
Edwards Lifesciences Corp	EW	606.50	63.72	38,646.18	0.15%			8.45%	0.01%
Ameriprise Financial Inc	AMP	102.63	314.57	32,283.06	0.12%	1.72%	0.00%	15.82%	0.02%
Zebra Technologies Corp	ZBRA	51.36	209.43	10,756.32					
Zimmer Biomet Holdings Inc	ZBH	208.96	104.41	21,817.93	0.08%	0.92%	0.00%	9.48%	0.01%
CBRE Group Inc	CBRE	304.79	69.34	21,134.35					
Camden Property Trust	CPT	106.77	84.88	9,062.72	0.03%	4.71%	0.00%	6.77%	0.00%
Mastercard Inc	MA	930.44	376.35	350,170.34	1.32%	0.61%	0.01%	17.85%	0.24%
CarMax Inc	KMX	158.67	61.09	9,693.03	0.04%			16.34%	0.01%
Intercontinental Exchange Inc	ICE	594.94	107.44	63,919.92	0.24%	1.56%	0.00%	9.87%	0.02%
Fidelity National Information Services Inc	FIS	592.47	49.11	29,095.96	0.11%	4.24%	0.00%	2.68%	0.00%
Chipotle Mexican Grill Inc	CMG	27.45	1,942.20	53,303.68				25.41%	
Wynn Resorts Ltd	WYNN	113.94	87.78	10,001.30		1.14%			
Live Nation Entertainment Inc	LYV	230.15	80.02	18,416.68					
Assurant Inc	AIZ	53.02	148.90	7,895.12	0.03%	1.88%	0.00%	14.70%	0.00%
NRG Energy Inc	NRG	229.12	42.38	9,709.98	0.04%	3.56%	0.00%	10.26%	0.00%
Regions Financial Corp	RF	938.38	14.53	13,634.62	0.05%	6.61%	0.00%	0.99%	0.00%
Monster Beverage Corp	MNST	1,047.52	51.10	53,528.17	0.20%			15.56%	0.03%
Mosaic Co/The	MOS	332.28	32.48	10,792.45		2.46%		22.93%	
Baker Hughes Co	BKR	1,006.23	34.42	34,634.57	0.13%	2.32%	0.00%	16.00%	0.02%
Expedia Group Inc	EXPE	137.84	95.29	13,134.87	0.05%			17.50%	0.01%
CF Industries Holdings Inc	CF	192.95	79.78	15,393.39		2.01%		44.50%	
Leidos Holdings Inc	LDOS	137.51	99.12	13,629.59	0.05%	1.53%	0.00%	6.45%	0.00%
APA Corp	APA	307.27	39.72	12,204.57		2.52%		-2.68%	
Alphabet Inc	GOOG	5,725.00	125.30	717,342.50	2.71%			16.65%	0.45%
First Solar Inc	FSLR	106.84	142.45	15,219.93	0.06%			19.80%	0.01%
TE Connectivity Ltd	TEL	313.94	117.85	36,997.71	0.14%	2.00%	0.00%	3.10%	0.00%
Discover Financial Services	DFS	250.06	82.08	20,524.76		3.41%		56.16%	
Linde PLC	LIN	484.89	382.16	185,305.56	0.70%	1.33%	0.01%	12.47%	0.09%
Visa Inc	V	1,594.00	235.10	374,749.40	1.41%	0.88%	0.01%	14.73%	0.21%
Mid-America Apartment Communities Inc	MAA	116.68	118.15	13,785.39	0.05%	4.74%	0.00%	2.36%	0.00%
Xylem Inc/NY	XYL	241.08	93.54	22,550.44	0.09%	1.41%	0.00%	12.00%	0.01%
Marathon Petroleum Corp	MPC	379.70	151.25	57,429.17		2.18%		83.00%	
Tractor Supply Co	TSCO	108.81	192.56	20,952.07	0.08%	2.14%	0.00%	3.81%	0.00%
Advanced Micro Devices Inc	AMD	1,615.67	98.50	159,143.59				27.10%	
ResMed Inc	RMD	147.09	141.22	20,772.33	0.08%	1.36%	0.00%	7.00%	0.01%
Mettler-Toledo International Inc	MTD	21.87	985.20	21,541.40	0.08%			8.29%	0.01%
Jacobs Solutions Inc	J	125.92	133.30	16,784.87	0.06%	0.78%	0.00%	9.26%	0.01%
Copart Inc	CPRT	960.18	43.52	41,787.16					
VICI Properties Inc	VICI	1,034.53	27.90	28,863.44	0.11%	5.95%	0.01%	11.05%	0.01%
Albemarle Corp	ALB	117.35	126.78	14,877.25		1.26%		25.23%	
Fortinet Inc	FTNT	785.34	57.17	44,897.72	0.17%			18.00%	0.03%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Moderna Inc	MRNA	380.59	75.96	28,909.84				-42.47%	
Essex Property Trust Inc	ESS	64.18	213.92	13,730.03	0.05%	4.32%	0.00%	9.46%	0.00%
CoStar Group Inc	CSGP	408.36	73.41	29,977.93	0.11%			20.00%	0.02%
Realty Income Corp	O	723.91	47.38	34,298.95		6.48%			
Westrock Co	WRK	256.40	35.93	9,212.56		3.37%		-6.74%	
Westinghouse Air Brake Technologies Corp	WAB	179.16	106.02	18,994.44	0.07%	0.64%	0.00%	12.86%	0.01%
Pool Corp	POOL	38.68	315.77	12,213.67		1.39%		-5.49%	
Western Digital Corp	WDC	324.15	40.15	13,014.42				-10.00%	
PepsiCo Inc	PEP	1,374.86	163.28	224,487.79	0.85%	3.10%	0.03%	8.70%	0.07%
Diamondback Energy Inc	FANG	178.82	160.32	28,668.10	0.11%	2.10%	0.00%	8.97%	0.01%
Palo Alto Networks Inc	PANW	310.82	243.02	75,534.50				20.50%	
ServiceNow Inc	NOW	205.00	581.85	119,279.25					
Church & Dwight Co Inc	CHD	246.05	90.94	22,375.51	0.08%	1.20%	0.00%	5.85%	0.00%
Federal Realty Investment Trust	FRT	81.52	91.19	7,434.08	0.03%	4.78%	0.00%	6.53%	0.00%
MGM Resorts International	MGM	350.89	34.92	12,253.04					
American Electric Power Co Inc	AEP	515.18	75.54	38,916.40	0.15%	4.66%	0.01%	4.83%	0.01%
SolarEdge Technologies Inc	SEDG	56.56	75.95	4,295.58	0.02%			19.59%	0.00%
Invitation Homes Inc	INVH	611.96	29.69	18,169.03	0.07%	3.50%	0.00%	4.51%	0.00%
PTC Inc	PTC	118.83	140.42	16,686.53	0.06%			16.99%	0.01%
JB Hunt Transport Services Inc	JBHT	103.14	171.87	17,727.19		0.98%		27.00%	
Lam Research Corp	LRCX	131.79	588.22	77,522.69	0.29%	1.36%	0.00%	5.44%	0.02%
Mohawk Industries Inc	MHK	63.68	80.38	5,118.76				-3.08%	
GE HealthCare Technologies Inc	GEHC	455.24	66.57	30,305.53	0.11%	0.18%	0.00%	12.70%	0.01%
Pentair PLC	PNR	165.30	58.12	9,607.18	0.04%	1.51%	0.00%	6.22%	0.00%
Vertex Pharmaceuticals Inc	VRTX	258.10	362.11	93,458.78	0.35%			13.55%	0.05%
Amcor PLC	AMCR	1,446.44	8.89	12,858.82	0.05%	5.62%	0.00%	1.33%	0.00%
Meta Platforms Inc	META	2,219.61	301.27	668,701.00				24.05%	
T-Mobile US Inc	TMUS	1,156.48	143.86	166,370.49		1.81%		38.46%	
United Rentals Inc	URI	67.78	406.27	27,537.39	0.10%	1.46%	0.00%	17.87%	0.02%
Honeywell International Inc	HON	659.25	183.26	120,814.34	0.46%	2.36%	0.01%	7.69%	0.04%
Alexandria Real Estate Equities Inc	ARE	173.78	93.13	16,183.67	0.06%	5.33%	0.00%	5.53%	0.00%
Delta Air Lines Inc	DAL	643.46	31.25	20,108.22		1.28%		30.85%	
Seagate Technology Holdings PLC	STX	209.18	68.25	14,276.81	0.05%	4.10%	0.00%	6.11%	0.00%
United Airlines Holdings Inc	UAL	326.73	35.01	11,438.78				46.54%	
News Corp	NWS	191.84	21.44	4,112.99	0.02%	0.93%	0.00%	8.00%	0.00%
Centene Corp	CNC	534.20	68.98	36,849.18	0.14%			4.72%	0.01%
Martin Marietta Materials Inc	MLM	61.80	408.94	25,274.13	0.10%	0.72%	0.00%	19.03%	0.02%
Teradyne Inc	TER	154.01	83.27	12,824.75	0.05%	0.53%	0.00%	7.82%	0.00%
PayPal Holdings Inc	PYPL	1,098.04	51.80	56,878.32	0.21%			15.96%	0.03%
Tesla Inc	TSLA	3,178.92	200.84	638,454.49				32.00%	
Arch Capital Group Ltd	ACGL	373.10	86.68	32,340.31	0.12%			14.50%	0.02%
Dow Inc	DOW	703.08	48.34	33,986.65	0.13%	5.79%	0.01%	0.93%	0.00%
Everest Group Ltd	EG	43.40	395.62	17,169.91		1.77%		35.22%	
Teledyne Technologies Inc	TDY	47.19	374.59	17,675.03	0.07%			6.36%	0.00%
News Corp	NWSA	379.59	20.68	7,849.82	0.03%	0.97%	0.00%	8.00%	0.00%
Exelon Corp	EXC	994.30	38.94	38,718.00	0.15%	3.70%	0.01%	4.00%	0.01%
Global Payments Inc	GPN	260.39	106.22	27,658.52	0.10%	0.94%	0.00%	13.33%	0.01%
Crown Castle Inc	CCI	434.00	92.98	40,353.32	0.15%	6.73%	0.01%	7.00%	0.01%
Aptiv PLC	APTV	282.82	87.20	24,662.25	0.09%			12.44%	0.01%
Align Technology Inc	ALGN	76.53	184.59	14,127.41					
Illumina Inc	ILMN	158.30	109.42	17,321.19					
Kenvue Inc	KVUE	1,914.89	18.60	35,617.03		4.30%			
Targa Resources Corp	TRGP	223.71	83.61	18,704.56	0.07%	2.39%	0.00%	15.00%	0.01%
LKQ Corp	LKQ	267.60	43.92	11,752.90		2.73%			
Zoetis Inc	ZTS	460.32	157.00	72,269.77	0.27%	0.96%	0.00%	10.91%	0.03%
Equinix Inc	EQIX	93.88	729.64	68,500.79	0.26%	2.34%	0.01%	15.33%	0.04%
Digital Realty Trust Inc	DLR	302.85	124.36	37,661.93	0.14%	3.92%	0.01%	6.80%	0.01%
Molina Healthcare Inc	MOH	58.30	332.95	19,410.99	0.07%			11.24%	0.01%
Las Vegas Sands Corp	LVS	764.49	47.46	36,282.74		1.69%			

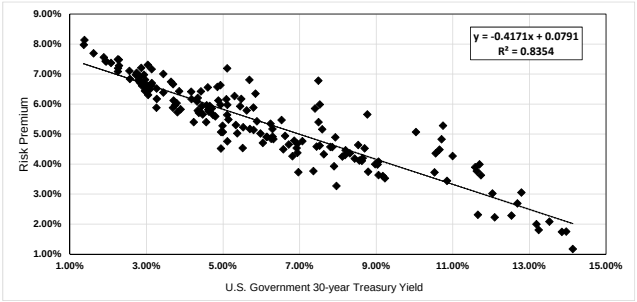
Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of October 31, 2023
[5] Source: Bloomberg Professional as of October 31, 2023
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and≤20%
[8] Source: Bloomberg Professional, as of October 31, 2023
[9] Equals [7] x [8]
[10] Source: Bloomberg Professional, as of October 31, 2023
[11] Equals [7] x [10]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.91%	10.55%	4.36%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%

Quarter	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	10.88%	5.70%	5.17%
2001.3	10.76%	5.53%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.25%	5.09%	6.16%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.85%	6.57%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	10.91%	4.93%	5.98%
2005.1	10.56%	4.71%	5.85%
2005.2	10.13%	4.47%	5.65%
2005.3	10.85%	4.42%	6.42%
2005.4	10.59%	4.65%	5.94%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	5.00%	5.07%
2006.4	10.39%	4.74%	5.64%
2007.1	10.39%	4.80%	5.59%

	[1]	[2]	[3]
Quarter	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.74%
2008.2	10.54%	4.57%	5.96%
2008.3	10.38%	4.45%	5.93%
2008.4	10.39%	3.64%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.41%
2009.3	10.41%	4.32%	6.09%
2009.4	10.54%	4.34%	6.20%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.37%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.70%	6.66%
2011.4	10.34%	3.04%	7.31%
2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.94%	6.98%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.27%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.05%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.57%	3.09%	6.49%
2018.3	9.66%	3.06%	6.60%
2018.4	9.44%	3.27%	6.17%
2019.1	9.57%	3.01%	6.55%
2019.2	9.58%	2.78%	6.79%
2019.3	9.57%	2.29%	7.28%
2019.4	9.74%	2.26%	7.49%
2020.1	9.45%	1.89%	7.56%
2020.2	9.52%	1.38%	8.14%
2020.3	9.34%	1.37%	7.98%
2020.4	9.32%	1.62%	7.69%
2021.1	9.45%	2.07%	7.38%
2021.2	9.46%	2.26%	7.20%
2021.3	9.37%	1.93%	7.43%
2021.4	9.37%	1.95%	7.42%
2022.1	9.34%	2.25%	7.08%
2022.2	9.35%	3.05%	6.30%
2022.3	9.14%	3.26%	5.88%
2022.4	9.72%	3.89%	5.83%
2023.1	9.71%	3.75%	5.96%
2023.2	9.54%	3.81%	5.73%
2023.3	9.63%	4.23%	5.40%
2023.4	9.47%	4.95%	4.52%
AVERAGE	11.46%	6.09%	5.37%
MEDIAN	11.00%	5.35%	5.62%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9139992
R Square	0.8353945
Adjusted R Square	0.8344484
Standard Error	0.0057010
Observations	176

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.02870	0.02870	883.07251	0.00000
Residual	174	0.00566	0.00003		
Total	175	0.03436			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0791	0.00	82.74	0.0000	0.0772	0.0810	0.0772	0.0810
U.S. Govt. 30-year Treasury	(0.4171)	0.01	(29.72)	0.0000	(0.4448)	(0.3894)	(0.4448)	(0.3894)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.84%	5.89%	10.74%
Blue Chip Near-Term Projected Forecast (Q1 2024 - Q1 2025) [5]	4.44%	6.06%	10.50%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.33%	10.13%
AVERAGE			10.46%

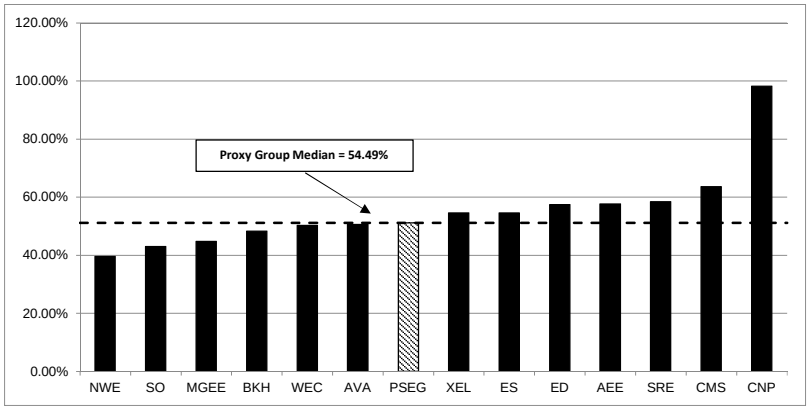
Notes:
[1] Source: Regulatory Research Associates, rate cases through October 31, 2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of October 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 11, November 1, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[7] See notes [4], [5] & [6]
[8] Equals 0.079130 + (-0.417135 x Column [7])
[9] Equals Column [7] + Column [8]

2024-2028 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2024	2025	2026	2027	2028	2024-28 Cap. Ex. / 2022 Net Plant
Ameren Corporation	AEE							
Capital Spending per Share			$12.55	$12.78	$13.00	$13.00	$13.00	
Common Shares Outstanding			269.00	277.00	285.00	285.00	285.00	
Capital Expenditures			$3,376.0	$3,538.7	$3,705.0	$3,705.0	$3,705.0	57.67%
Net Plant		$31,262.0						
Avista Corporation	AVA							
Capital Spending per Share			$6.35	$6.55	$6.75	$6.75	$6.75	
Common Shares Outstanding			78.50	81.75	85.00	85.00	85.00	
Capital Expenditures			$498.5	$535.5	$573.8	$573.8	$573.8	50.60%
Net Plant		$5,444.7						
Black Hills Corporation	BKH							
Capital Spending per Share			$9.50	$9.38	$9.25	$9.25	$9.25	
Common Shares Outstanding			69.00	70.00	71.00	71.00	71.00	
Capital Expenditures			$655.5	$656.3	$656.8	$656.8	$656.8	48.28%
Net Plant		$6,797.9						
CenterPoint Energy, Inc.	CNP							
Capital Spending per Share			$7.05	$8.03	$9.00	$9.00	$9.00	
Common Shares Outstanding			632.00	633.00	634.00	634.00	634.00	
Capital Expenditures			$4,455.6	$5,079.8	$5,706.0	$5,706.0	$5,706.0	98.20%
Net Plant		$27,143.0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$9.50	$9.63	$9.75	$9.75	$9.75	
Common Shares Outstanding			295.00	297.50	300.00	300.00	300.00	
Capital Expenditures			$2,802.5	$2,863.4	$2,925.0	$2,925.0	$2,925.0	63.58%
Net Plant		$22,713.0						
Consolidated Edison, Inc.	ED							
Capital Spending per Share			$14.50	$15.25	$16.00	$16.00	$16.00	
Common Shares Outstanding			345.00	345.00	345.00	345.00	345.00	
Capital Expenditures			$5,002.5	$5,261.3	$5,520.0	$5,520.0	$5,520.0	57.36%
Net Plant		$46,766.0						
Eversource Energy	ES							
Capital Spending per Share			$11.00	$11.00	$11.00	$11.00	$11.00	
Common Shares Outstanding			355.00	357.50	360.00	360.00	360.00	
Capital Expenditures			$3,905.0	$3,932.5	$3,960.0	$3,960.0	$3,960.0	54.60%
Net Plant		$36,113.0						
MGE Energy, Inc.	MGEE							
Capital Spending per Share			$4.00	$4.63	$5.25	$5.25	$5.25	
Common Shares Outstanding			36.16	36.16	36.16	36.16	36.16	
Capital Expenditures			$144.6	$167.2	$189.8	$189.8	$189.8	44.72%
Net Plant		$1,971.1						
NorthWestern Corporation	NWE							
Capital Spending per Share			$7.75	$7.38	$7.00	$7.00	$7.00	
Common Shares Outstanding			62.00	62.00	62.00	62.00	62.00	
Capital Expenditures			$480.5	$457.3	$434.0	$434.0	$434.0	39.59%
Net Plant		$5,657.5						
Sempra Energy	SRE							
Capital Spending per Share			$8.55	$8.78	$9.00	$9.00	$9.00	
Common Shares Outstanding			630.00	630.00	630.00	630.00	630.00	
Capital Expenditures			$5,386.5	$5,528.3	$5,670.0	$5,670.0	$5,670.0	58.44%
Net Plant		$47,782.0						
Southern Company	SO							
Capital Spending per Share			$7.85	$7.68	$7.50	$7.50	$7.50	
Common Shares Outstanding			1070.00	1070.00	1070.00	1070.00	1070.00	
Capital Expenditures			$8,399.5	$8,212.3	$8,025.0	$8,025.0	$8,025.0	43.02%
Net Plant		$94,570.0						
Wisconsin Energy Corporation	WEC							
Capital Spending per Share			$9.30	$9.28	$9.25	$9.25	$9.25	
Common Shares Outstanding			315.43	315.43	315.43	315.43	315.43	
Capital Expenditures			$2,933.5	$2,925.6	$2,917.7	$2,917.7	$2,917.7	50.19%
Net Plant		$29,114.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$9.25	$9.38	$9.50	$9.50	$9.50	
Common Shares Outstanding			553.00	556.50	560.00	560.00	560.00	
Capital Expenditures			$5,115.3	$5,217.2	$5,320.0	$5,320.0	$5,320.0	54.49%
Net Plant		$48,253.0						
Public Service Electric and Gas Company	PSEG							
Capital Expenditures [8]								51.16%
Net Plant [9]		$33,230.0						
PSEG CapEx Total (2023 - 2027)								$17,000.0
PSEG CapEx Annual Average								
Proxy Group Median								54.49%
PSEG as % Proxy Group Median								0.94

Notes:
[1] - [6] Source: Value Line, dated October 20, 2023, September 8 2023, and August 11, 2023.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Source: PSEG December 2023 Investor Update, approximate mid-point of PSE&G capital spending range 2023-2027 $16.0-$18.5B.
[9] Source: From the PSEG 2022 10K. Net utility plant is from the PSE&G Consolidated Balance Sheet, page 68, Net Property, Plant and Equipment (December 31, 2022 balance is $32,830 million); the Energy Efficiency regulatory asset is from the Financial Statement Note 7, page 88 (Green Program Recovery Charges (GPRC), December 31, 2022 non-current asset balance is $447 million).

2024-2028 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT



Projected CAPEX / 2022 Net Plant

Rank	Company		2024-2028
1	NorthWestern Corporation	NWE	39.59%
2	Southern Company	SO	43.02%
3	MGE Energy, Inc.	MGEE	44.72%
4	Black Hills Corporation	BKH	48.28%
5	Wisconsin Energy Corporation	WEC	50.19%
6	Avista Corporation	AVA	50.60%
7	Public Service Electric and Gas Company	PSEG	51.16%
8	Xcel Energy Inc.	XEL	54.49%
9	Eversource Energy	ES	54.60%
10	Consolidated Edison, Inc.	ED	57.36%
11	Ameren Corporation	AEE	57.67%
12	Sempra Energy	SRE	58.44%
13	CMS Energy Corporation	CMS	63.58%
14	CenterPoint Energy, Inc.	CNP	98.20%
	Proxy Group Median		51.16%
	PSEG/Proxy Group		0.94

Notes:
Source: Exhibit AEB-9, page 1 col. [7]

REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Revenue Stabilization				Capital Cost Recovery				
Company	Operating Subsidiary	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Revenue Stabilization	Traditional Generation	Renewable/ Non-Traditional Generation	Delivery Infrastructure	Environmental Compliance	Overall Capital Cost Recovery
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Historical	Yes	Yes	No	Yes	No	Yes	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	Yes	No	Yes	No	No	Yes	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	No	Yes	Yes	No	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	No	No	No	No	No
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	No	No	No	No	No
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	No	No	No	No	No
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	No	No	No	No	No
Black Hills Corporation	Black Hills Energy Arkansas Inc.	Arkansas	Gas	Historical	Yes	Yes	No	Yes	No	No	Yes	No	Yes
	Black Hills Colorado Electric Inc.	Colorado	Electric	Historical	No	No	No	No	Yes	Yes	No	No	Yes
	Black Hills Gas Distribution LLC	Colorado	Gas	Historical	No	No	No	No	No	No	Yes	No	Yes
	Black Hills Iowa Gas Utility Co.	Iowa	Gas	Historical	No	No	No	No	No	No	Yes	No	Yes
	Black Hills/Kansas Gas Utility Co.	Kansas	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Black Hills Nebraska Gas LLC	Nebraska	Gas	Historical	No	No	No	No	No	No	Yes	No	Yes
	Black Hills Power Inc.	South Dakota	Electric	Historical	No	No	No	No	No	No	No	Yes	Yes
	Black Hills Wyoming Gas LLC	Wyoming	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Cheyenne Light Fuel & Power Co.	Wyoming	Electric	Historical	Yes	No	No	Yes	No	No	No	No	No
CenterPoint Energy, Inc.	Indiana Gas Co.	Indiana	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Southern Indiana Gas & Electric Co.	Indiana	Electric	Historical	Yes	No	No	Yes	No	No	Yes	Yes	Yes
	Southern Indiana Gas & Electric Co.	Indiana	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	CenterPoint Energy Arkla	Louisiana (PSC)	Gas	Historical	Yes	Yes	Yes	Yes	No	No	No	No	No
	CenterPoint Energy Resources Corp.	Minnesota	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
	Vectren Energy Delivery of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	No	No	No	No	Yes	No	Yes
	CenterPoint Energy Houston Electric LLC	Texas (PUC)	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes
	CenterPoint Energy Resources Corp.	Texas (RRC)	Gas	Historical	No	No	No	No	No	No	Yes	No	Yes
CMS	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
Consolidated Edison, Inc.	Rockland Electric Co.	New Jersey	Electric	Partially Forecast	Yes	No	No	Yes	No	No	No	Yes	Yes
	Consolidated Edison Co. of New York Inc.	New York	Electric	Fully Forecast	Yes	No	No	Yes	No	Yes	Yes	No	Yes
	Consolidated Edison Co. of New York Inc.	New York	Gas	Fully Forecast	Yes	No	No	Yes	No	No	Yes	No	Yes
	Orange & Rockland Utilities Inc.	New York	Electric	Fully Forecast	Yes	No	No	Yes	No	Yes	No	No	Yes
	Orange & Rockland Utilities Inc.	New York	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
Eversource Energy	Connecticut Light and Power Co.	Connecticut	Electric	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Yankee Gas Services Co.	Connecticut	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Eversource Gas Co. of Massachusetts	Massachusetts	Gas	Historical	Yes	No	No	Yes	No	No	Yes	Yes	Yes
	NSTAR Electric Co.	Massachusetts	Electric	Historical	Yes	No	No	Yes	No	Yes	Yes	No	Yes
	NSTAR Gas Co.	Massachusetts	Gas	Historical	Yes	No	No	Yes	No	No	Yes	Yes	Yes
	Public Service Co. of New Hampshire	New Hampshire	Electric	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
MGE Energy, Inc.	Madison Gas & Electric Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes
	Madison Gas & Electric Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	No	No	No	No	No	No	No	No	No
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No	No	No	No	No	No
Sempra Energy	San Diego Gas & Electric Co.	California	Electric	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
	San Diego Gas & Electric Co.	California	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
	Southern California Gas Co.	California	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No	No	No
	Oncor Electric Delivery Co.	Texas (PUC)	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Historical	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes
	Atlanta Gas Light Co.	Georgia	Gas	Fully Forecast	No	No	No	No	No	No	Yes	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	No	No	No	Yes	No	No	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	Yes	No	Yes	No	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	No	No	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	No	No	Yes	No	No	No	No	No
	Virginia Natural Gas Inc.	Virginia	Gas	Fully Forecast	Yes	No	No	Yes	No	No	Yes	No	Yes
Wisconsin Energy Corporation	North Shore Gas Co.	Illinois	Gas	Fully Forecast	Yes	Yes	No	Yes	No	No	Yes	Yes	Yes
	Peoples Gas Light & Coke Co.	Illinois	Gas	Fully Forecast	Yes	Yes	No	Yes	No	No	Yes	Yes	Yes
	Michigan Gas Utilities Corp.	Michigan	Gas	Fully Forecast	No	No	No	No	No	No	Yes	No	Yes
	Upper Michigan Energy Resources Corp.	Michigan	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes
	Minnesota Energy Resources Corp.	Minnesota	Gas	Fully Forecast	Yes	No	No	Yes	No	No	Yes	No	Yes
	Wisconsin Electric Power Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes
	Wisconsin Electric Power Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
	Wisconsin Gas LLC	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
	Wisconsin Public Service Corp.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	No	No	No	No
	Wisconsin Public Service Corp.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Partially Forecast	Yes	No	No	Yes	No	Yes	No	No	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	No	No	Yes	No	Yes
	Northern States Power Co. - Minnesota	Minnesota	Electric	Fully Forecast	Yes	No	No	Yes	No	Yes	No	Yes	Yes
	Northern States Power Co. - Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No	No	No	Yes	No	Yes

REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Decoupling	[3] Formula-Based Rates	[4] Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Traditional Generation	[7] Renewable/ Non-Traditional Generation	[8] Delivery Infrastructure	[9] Environmental Compliance	[10] Overall Capital Cost Recovery
					Revenue Stabilization				Capital Cost Recovery				
	Southwestern Public Service Co.	New Mexico	Electric	Historical	No	No	No	No	No	Yes	No	No	Yes
	Northern States Power Co. - Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes	No	Yes
	Northern States Power Co. - Minnesota	North Dakota	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
	Northern States Power Co. - Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes	No	Yes	Yes	Yes
	Southwestern Public Service Co.	Texas (PUC)	Electric	Historical	No	No	No	No	No	No	No	No	No
	Northern States Power Co. - Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	No	No	No	No
	Northern States Power Co. - Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No
Proxy Group Average			Fully Forecast	35				Yes	45			Yes	50
			Partially Forecast	3				No	34			No	29
			Historical	41									
			Forecast	48.10%	44.30%			% Yes	57.0%			% Yes	63.3%
Public Service Electric and Gas Co.	[11]	New Jersey	Electric	Partially Forecast	Yes	No	No	Yes	No	No	Yes	Yes	Yes
Public Service Electric and Gas Co.	[11]	New Jersey	Gas	Partially Forecast	Yes	No	No	Yes	No	No	Yes	Yes	Yes

Notes:
[1] Regulatory Research Associates, effective as of October 31, 2023
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[3] - [4] Form 10-K; company tariffs; S&P Global Market Intelligence
[5] If either [2], [3], or [4] equals "Yes", then "Yes"; if not, then "No"
[6] - [9] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[10] If [6] or [7] or [8] or [9] equals "Yes", then "Yes"; if not, then "No"
[11] Data provided by the Company

COMPARISON OF PSEG AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

Ultimate Parent Company	Jurisdiction	[1] RRA Rank	[2] RRA Numeric Rank
Ameren Corporation	Illinois	Average/2	5
	Missouri	Average/3	6
Avista Corporation	Alaska	Below Average/1	7
	Idaho	Average/2	5
	Oregon	Average/2	5
	Washington	Average/3	6
Black Hills Corporation	Arkansas	Average/1	4
	Colorado	Average/1	4
	Iowa	Above Average/3	3
	Kansas	Below Average/1	7
	Nebraska	Average/1	4
	South Dakota	Average/2	5
	Wyoming	Average/2	5
CenterPoint Energy, Inc.	Indiana	Average/1	4
	Louisiana (PSC)	Average/2	5
	Minnesota	Average/2	5
	Ohio	Average/3	6
	Texas (PUC)	Average/3	6
	Texas (RRC)	Average/1	4
CMS	Michigan	Above Average/3	3
Consolidated Edison, Inc.	New Jersey	Below Average/1	7
	New York	Average/2	5
Eversource Energy	Connecticut	Below Average/2	8
	Massachusetts	Average/2	5
	New Hampshire	Average/2	5
MGE Energy, Inc.	Wisconsin	Above Average/3	3
NorthWestern Corporation	Montana	Below Average/1	7
	Nebraska	Average/1	4
	South Dakota	Average/2	5
Sempra Energy	California	Average/1	4
	Texas (PUC)	Average/3	6
Southern Company	Alabama	Above Average/1	1
	Georgia	Above Average/2	2
	Illinois	Average/2	5
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Virginia	Average/2	5
Wisconsin Energy Corporation	Illinois	Average/2	5
	Michigan	Above Average/3	3
	Minnesota	Average/2	5
	Wisconsin	Above Average/3	3
Xcel Energy Inc.	Colorado	Average/1	4
	Minnesota	Average/2	5
	New Mexico	Below Average/2	8
	North Dakota	Average/1	4
	South Dakota	Average/2	5
	Texas (PUC)	Average/3	6
	Wisconsin	Above Average/3	3
Proxy Group Average		Average/1 to Average/2	4.75
Public Service Electric and Gas Co.	New Jersey	Below Average/1	7

Notes
[1] Source: State Regulatory Evaluations, Regulatory Research Associates, as of August 23, 2023.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

COMPARISON OF PSEG AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

Ultimate Parent Company	Jurisdiction	[1] S&P Rank	[2] Numeric Rank
Ameren Corporation	Illinois	Very credit supportive	3
	Missouri	Very credit supportive	3
Avista Corporation	Alaska	More credit supportive	4
	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
Black Hills Corporation	Arkansas	Highly credit supportive	2
	Colorado	Very credit supportive	3
	Iowa	Most credit supportive	1
	Kansas	Highly credit supportive	2
	Nebraska	Very credit supportive	3
	South Dakota	Very credit supportive	3
	Wyoming	Very credit supportive	3
CenterPoint Energy, Inc.	Indiana	Highly credit supportive	2
	Louisiana (PSC)	Highly credit supportive	2
	Minnesota	Highly credit supportive	2
	Ohio	Very credit supportive	3
	Texas (PUC)	Very credit supportive	3
	Texas (RRC)	Highly credit supportive	2
CMS	Michigan	Most credit supportive	1
Consolidated Edison, Inc.	New Jersey	More credit supportive	4
	New York	Very credit supportive	3
Eversource Energy	Connecticut	More credit supportive	4
	Massachusetts	Highly credit supportive	2
	New Hampshire	Highly credit supportive	2
MGE Energy, Inc.	Wisconsin	Most credit supportive	1
NorthWestern Corporation	Montana	More credit supportive	4
	Nebraska	Very credit supportive	3
	South Dakota	Very credit supportive	3
Sempra Energy	California	More credit supportive	4
	Texas (PUC)	Very credit supportive	3
Southern Company	Alabama	Most credit supportive	1
	Georgia	Highly credit supportive	2
	Illinois	Very credit supportive	3
	Mississippi	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Wisconsin Energy Corporation	Illinois	Very credit supportive	3
	Michigan	Most credit supportive	1
	Minnesota	Highly credit supportive	2
	Wisconsin	Most credit supportive	1
Xcel Energy Inc.	Colorado	Very credit supportive	3
	Minnesota	Highly credit supportive	2
	New Mexico	Credit supportive	5
	North Dakota	Highly credit supportive	2
	South Dakota	Very credit supportive	3
	Texas (PUC)	Very credit supportive	3
	Wisconsin	Most credit supportive	1
Proxy Group Average		Very Credit Supportive to Highly Credit Supportive	2.58
Public Service Electric and Gas Co.	New Jersey	More credit supportive	4

Notes
[1] S&P Global Ratings, "North American Utility Regulatory Jurisdictions Update: No Revised Assessments, But Notable Developments," July 10, 2023.
[2] Most Credit Supp. = 1, Highly Credit Supp. = 2, Very Credit Supp. = 3, More Credit Supp. = 4, Credit Supp. = 5

CAPITAL STRUCTURE ANALYSIS

Proxy Group Company	Ticker	Most Recent 8 Quarters (2021Q3 - 2023Q2) Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Total Capitalization
Ameren Corporation	AEE	53.17%	46.26%	0.57%	100%
Avista Corporation	AVA	49.76%	50.24%	0.00%	100%
Black Hills Corporation	BKH	66.21%	33.79%	0.00%	100%
CenterPoint Energy, Inc.	CNP	47.21%	52.79%	0.00%	100%
CMS Energy Corporation	CMS	51.59%	48.21%	0.19%	100%
Consolidated Edison, Inc.	ED	48.18%	51.82%	0.00%	100%
Eversource Energy	ES	54.62%	44.69%	0.69%	100%
MGE Energy, Inc.	MGEE	60.59%	39.41%	0.00%	100%
NorthWestern Corporation	NWE	49.29%	50.71%	0.00%	100%
Sempra Energy	SRE	55.16%	44.79%	0.04%	100%
Southern Company	SO	55.56%	44.20%	0.24%	100%
Wisconsin Energy Corporation	WEC	57.26%	42.58%	0.16%	100%
Xcel Energy Inc.	XEL	54.44%	45.56%	0.00%	100%
Average		54.08%	45.77%	0.15%	
Median		54.44%	45.56%	0.00%	
Maximum		66.21%	52.79%	0.69%	
Minimum		47.21%	33.79%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of the operating subsidiaries.
[2] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
MICHAEL J. ADAMS

Submitted on Behalf of PUBLIC SERVICE ELECTRIC AND GAS COMPANY

December 29, 2023

P-6

TABLE OF CONTENTS

I. INTRODUCTION ..... - 1 -

II. SOURCE DATA ..... - 5 -

III. ELECTRIC BENCHMARKING ANALYSES ..... - 8 -

IV. GAS BENCHMARKING ANALYSES ..... - 18 -

V. RELIABILITY ..... - 25 -

VI. CUSTOMER SATISFACTION ..... - 28 -

VII. SUMMARY AND CONCLUSIONS ..... - 30 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL J. ADAMS
SENIOR VICE PRESIDENT, CONCENTRIC ENERGY ADVISORS, INC.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael J. Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom are you employed?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe your educational background and experience.

A. A summary of my educational background and experience is set forth in Appendix A to my testimony.

Q. On whose behalf are you appearing in this proceeding?

A. I am submitting this direct testimony on behalf of Public Service Electric and Gas Company ("PSE&G" or "the Company").

Q. What is the purpose of your direct testimony?

A. I was retained by the Company to prepare benchmarking analyses evaluating the financial and operational performance of PSE&G's electric and gas business operations.

Q. Please describe the nature of the analyses that you performed to assess PSE&G's performance.

A. I benchmarked PSE&G's electric business performance related to cost control, reliability and customer satisfaction against four peer groups to assess the Company's performance. Similarly, PSE&G's gas business performance related to cost control and customer satisfaction was benchmarked against four peer groups of comparable companies. The peer group analyses evaluated PSE&G's performance against national, regional, and New Jersey regulated utilities, as well as the operating companies included in Company witness Bulkley's return on equity peer group.

Q. Please generally summarize your findings and conclusions based upon the results of the benchmarking analyses.

A. Overall, I found that both PSE&G's electric and gas businesses performed very well when compared to its peer groups, which indicates a well-managed company that is effectively focused on controlling costs while providing high levels of reliability and customer satisfaction.

Q. How are you proposing that the results of your benchmarking analyses be used in this rate proceeding?

A. I believe it is reasonable for the Board of Public Utilities (the "Board" or the "BPU") to consider the Company's performance in areas such as fiscal responsibility, operational performance, service quality and customer satisfaction when establishing the authorized rate of return for the Company. Given PSE&G's strong performance in each of these areas, in my opinion, it is appropriate for the BPU to set PSE&G's ROE at the upper end of the range of

return on equity in recognition of the Company's consistently strong cost control, operational performance, service quality and customer satisfaction.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring PSE&G Schedules MJA-B-1 through MJA-B-25 which are identified below and discussed in my testimony.

Schedules	Description
MJA-B-1	Electric Peer Group Composition
MJA-B-2	Gas Peer Group Composition
MJA-B-3	Distribution Operations and Maintenance ("O&M") expense per electric customer
MJA-B-4	Distribution O&M per MWh sold
MJA-B-5	Administrative and General ("A&G") expense per electric customer
MJA-B-6	A&G expense per MWh sold
MJA-B-7	Salaries, Wages, Pensions, and Benefits expense per employee
MJA-B-8	Total O&M (excluding transmission and production) expense per electric customer
MJA-B-9	Total O&M (excluding transmission and production) expense per MWh sold
MJA-B-10	Distribution O&M expense per gas customer
MJA-B-11	Distribution O&M per Mcf sold
MJA-B-12	A&G expense per gas customer
MJA-B-13	A&G expense per Mcf sold
MJA-B-14	Total Non-Production O&M expense per gas customer
MJA-B-15	Total Non-Production O&M expense per Mcf sold
MJA-B-16	SAIDI – NJ Companies
MJA-B-17	SAIFI – NJ Companies
MJA-B-18	CAIDI – NJ Companies
MJA-B-19	SAIFI – IEEE
MJA-B-20	CAIDI – IEEE
MJA-B-21	SAIDI – IEEE
MJA-B-22	J.D. Power - Residential Electric Customers
MJA-B-23	J.D. Power - Business Electric Customers
MJA-B-24	J.D. Power - Residential Gas Customers
MJA-B-25	J.D. Power - Business Gas Customers

II. SOURCE DATA

Q. What years were included in the benchmarking analyses?

A. I used the most current publicly available information for PSE&G and the peer companies at the time the analyses were prepared in the second half of 2023. For both the electric and gas businesses, information for the calendar years 2013 through 2022 was used for the benchmarking analyses.

Q. Against what peer groups did you benchmark PSE&G's electric business operations?

A. PSE&G was benchmarked against four separate peer groups. The "Electric Group" included all operating companies classified by S&P Capital IQ Pro as "Electric Utility" or "Diversified Utility" which owned no regulated generation, and had a customer count of more than 500,000. The "Electric Group" included 25 companies in each year of the analyses.[1]

The "Regional Group" included all companies in the "Electric Group" having electric distribution operations in Connecticut, Delaware, Maryland, New Jersey, New York, or Pennsylvania. The "Regional Group" included 16 companies for each year of the analyses.

The "New Jersey Group" included all companies with electric distribution operations in New Jersey. The "New Jersey Group" included four companies for each year of the analyses.

The Return on Equity ("ROE") proxy group included all operating companies classified by S&P Capital IQ Pro as "Electric Utility" or "Diversified Utility" which owned no regulated

[1] The number of companies benchmarked in the Salaries, Wages, Pensions, and Benefits expense per employee analysis is slightly lower for each proxy group due to lack of available data.

generation and were owned by the holding companies in the proxy group included in Company witness Bulkley's cost of capital recommendation. The "ROE Proxy Group" included 11 companies for each year of the analyses.

The companies included in each electric peer group are set forth on Schedule MJA-B-1.

Q. What companies were included in the benchmarking of PSE&G's gas business?

A. PSE&G's gas business was benchmarked against four separate peer groups. The "LDC Group" included all natural gas distribution companies with a customer count of more than 500,000. The LDC Group included 41 companies.[2]

The "Regional Group" included all companies in the "LDC Group" having natural gas distribution operations in Connecticut, Delaware, Maryland, New Jersey, New York, or Pennsylvania. There were 11 companies in the Regional Group.

The "New Jersey Group" included all companies with natural gas distribution operations in New Jersey. The "New Jersey Group" included four companies for each year of the analyses.

The Return on Equity ("ROE") proxy group included all natural gas distribution companies that were owned by the holding companies in the proxy group included in Company witness Bulkley's cost of capital recommendation. The "ROE Proxy Group" included 44 companies.[3]

[2] The number of companies included in the analysis varied between 34 to 41 due to data availability for certain metrics in certain years.

[3] The number of companies included in the analysis varied between 25 to 44 due to data availability for certain metrics in certain years.

The companies included in the gas company peer groups are set forth in Schedule MJA-B-2.

Q. Is the information that you used to benchmark PSE&G's electric and gas operations publicly available?

A. Yes. All of the information that was used in the benchmarking analyses was obtained from publicly available sources. The data relied upon for my analyses was obtained from the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA"), the Institute of Electrical and Electronics Engineers ("IEEE"), and JD Power.

Q. What modifications were made to the data contained in the publicly available information to complete the benchmarking analyses?

A. No modifications were made to the data obtained from the referenced sources.[4] To ensure that the data was comparable across companies, each metric was compared on a cost per customer basis (i.e., the reported expense level was divided by the reported total number of customers) or a per unit sold basis (i.e., per mega-watt hour ("MWh") sold for the electric business or per million cubic feet ("Mcf") sold for the gas business).

[4] The A&G benchmarking analysis excluded amounts booked to FERC Account 926 (Employee Pensions and Benefits) because of the volatile nature of this account and the balances reported oscillating between positive and negative values. In light of PSE&G's pension and OPEB income in recent years, this adjustment is conservative.

III. ELECTRIC BENCHMARKING ANALYSES

Q. What metrics did you use to evaluate PSE&G's operational performance against that of the peer companies?

A. The following metrics were used to evaluate PSE&G's electric business cost performance against that of its peer companies:

1. Distribution Operations and Maintenance ("O&M") expense per electric customer;
2. Distribution O&M per MWh sold;
3. Administrative and General ("A&G") expense per electric customer;
4. A&G expense per MWh sold;
5. Salaries, Wages, Pensions, and Benefits expense per employee;
6. Total O&M (excluding transmission and production) expense per electric customer;[5] and
7. Total O&M (excluding transmission and production) expense per MWh sold.

Q. Please explain why it is appropriate to evaluate PSE&G's performance based upon the metrics set forth above.

A. The items that most directly impact customers' perceptions and experiences with their utility company revolve around costs (which are a driver of rates), service reliability, and how well the utility responds when the customer has an issue pertaining to their service. For that reason, I chose the metrics that I believe best illustrate PSE&G's performance in each of the above areas. The cost metrics were evaluated both on a cost per customer basis and a cost per

[5] Total O&M equals Distribution O&M plus A&G expense.

unit sold basis (i.e., per MWh for the electric business and per Mcf for the gas business). The service reliability and customer satisfaction metrics are discussed later in my testimony.

Q. How did PSE&G perform when compared to its peer companies on a distribution O&M expense per electric customer basis?

A. As shown on Schedule MJA-B-3, PSE&G's distribution O&M per customer ranged from a low of $73.70 in 2013 to a high of $87.26 in 2018. The Electric Group mean ranged from a low of $111.41 in 2013 to a high of $172.26 in 2022. The Regional Group mean ranged from a low of $115.83 in 2013 to a high of $186.82 in 2022. The New Jersey Group mean ranged from a low of $120.08 in 2013 to a high of $233.52 in 2020. The ROE Proxy Group mean ranged from a low of $151.90 in 2013 to a high of $185.36 in 2022. Therefore, PSE&G's electric distribution O&M expense per customer was consistently below (i.e., performed better than) the group means for each of the four comparison groups.

The cumulative average growth rate ("CAGR") of PSE&G's electric distribution O&M expenses per customer over the 10-year period examined was 0.32 percent. The Electric Group's CAGR over the same period was 4.96 percent, while the Regional Group's was 5.46 percent. The New Jersey Group's CAGR was 6.72 percent, while the ROE Proxy Group's was 2.24 percent. Therefore, in each comparison, PSE&G's electric distribution O&M expenses increased at a significantly lower rate over the period examined than those of the peer groups.

In 2022, PSE&G's electric distribution O&M expense per customer of $75.86 was approximately 56 percent lower than the Electric Group mean; 59 percent lower than the Regional Group mean; 65 percent lower than the New Jersey Group mean; and 59 percent lower than the ROE Proxy Group mean.

Q. How did PSE&G perform when compared to the peer companies on a distribution expense per MWh basis?

A. As shown on Schedule MJA-B-4, PSE&G's electric distribution O&M expense per MWh sold ranged from a low of $3.92 in 2013 to a high of $4.78 in 2020 over the ten-year period. The Electric Group mean ranged from a low of $5.76 in 2013 to a high of $11.04 in 2022 over the same period. The Regional Group mean ranged from a low of $5.93 in 2013 to a high of $10.71 in 2022 over the ten-year period. The New Jersey Group mean ranged from a low of $6.10 in 2013 to a high of $13.38 in 2020. The ROE Proxy Group mean ranged from a low of $7.09 in 2013 to a high of $12.77 in 2021. Therefore, PSE&G's electric distribution O&M expense per megawatt-hour sold was consistently below (i.e., performed better than) the group means for each of the four comparison groups.

The CAGR of PSE&G's electric distribution O&M expenses per MWh sold over the 10-year period examined was 1.20 percent. The Electric Group's CAGR over the same period was 7.50 percent, while the Regional Group's was 6.82 percent. The New Jersey Group's CAGR was 6.79 percent, while the ROE Proxy Group's was 6.63 percent. Therefore, PSE&G's electric distribution expense per MWh sold increased at a significantly lower rate over the years examined than that of the peer groups.

In 2022, PSE&G's distribution O&M expense per MWh sold of $4.36 was approximately 60 percent lower than the Electric Group mean; 59 percent lower than the Regional Group mean; 63 percent lower than the New Jersey Group mean; and 66 percent lower than the ROE Proxy Group mean.

Q. Did you compare PSE&G's A&G expense per customer to those of the peer group means?

A. Yes. As shown on Schedule MJA-B-5, PSE&G's A&G expense per customer was well below the group means for each of the four comparison groups, for the time period examined.

PSE&G's A&G expense per customer ranged from a low of $49.12 in 2014 to a high of $71.69 in 2022. The Electric Group mean ranged from a low of $99.62 in 2013 to a high of $130.43 in 2022. The Regional Group mean ranged from a low of $108.05 in 2013 to a high of $129.92 in 2022. The New Jersey Group mean ranged from a low of $95.99 in 2013 to a high of $155.25 in 2022. The ROE Proxy Group mean ranged from a low of $133.23 in 2018 to a high of $167.66 in 2013. Therefore, PSE&G's A&G expense per customer was consistently below (i.e., performed better than) the group means for each of the four comparison groups.

The CAGR of PSE&G's A&G expense per customer over the 10-year period examined was 3.64 percent. The Electric Group's CAGR over the same period was 3.04 percent, while the Regional Group's was 2.07 percent. The New Jersey Group's CAGR was 5.49 percent, while the ROE Proxy Group's was negative 1.38 percent. Therefore, PSE&G's A&G expense per customer increased at a rate higher than those of the Electric, Regional, and ROE groups, and lower than that of the New Jersey group.

In 2022, PSE&G's A&G expense per customer of $71.69 was approximately 45 percent lower than the Electric Group mean; 45 percent lower than the Regional Group mean; 54 percent lower than the New Jersey Group mean; and 52 percent lower than the ROE proxy group mean.

Q. How did PSE&G perform when compared to the peer companies on an A&G expense per MWh basis?

A. As shown on Schedule MJA-B-6, PSE&G's electric A&G expense per MWh sold ranged from a low of $2.65 in 2014 to a high of $4.12 in 2022. The Electric Group mean ranged from a low of $5.35 in 2013 to a high of $8.62 in 2022. The Regional Group mean ranged from a low of $5.68 in 2013 to a high of $7.32 in 2022. The New Jersey Group mean ranged from a low of $4.83 in 2013 to a high of $8.65 in 2022. The ROE Proxy Group mean ranged from a low of $7.04 in 2017 to a high of $9.62 in 2022. Therefore, PSE&G's A&G expense per MWh sold was consistently below (i.e., performed better than) the group means for each of the four comparison groups.

The CAGR of PSE&G's A&G expense per MWh sold over the 10-year period examined was 4.55 percent. The Electric Group's CAGR over the same period was 5.45 percent, while the Regional Group's was 2.87 percent. The New Jersey Group's CAGR was 6.69 percent, while the ROE Proxy Group's was 2.63 percent. PSE&G's A&G expense per MWh sold increased at a rate higher than that of the Regional and ROE Proxy Groups, and lower than those of the Electric and New Jersey groups.

In 2022, PSE&G's A&G expense per MWh sold of $4.12 was approximately 52 percent lower than the Electric Group mean; 44 percent lower than the Regional Group mean; 52 percent lower than the New Jersey Group mean; and 57 percent lower than the ROE Proxy Group mean.

Q. Did you compare PSE&G's salaries, wages, pensions, and benefits expenses on a per employee basis to those of the peer companies?

A. Yes. As shown on Schedule MJA-B-7, PSE&G's salaries, wages, pensions, and benefits expense per employee ranged from a low of $117.95 in 2019 to a high of $129.04 in 2018. The Electric Group mean ranged from a low of $109.34 in 2013 to a high of $154.64 in 2020. The Regional Group mean ranged from a low of $107.60 in 2013 to a high of $150.04 in 2020. The New Jersey Group mean ranged from a low of $80.79 in 2021 to a high of $156.76 in 2014. The ROE Proxy Group mean ranged from a low of $138.21 in 2014 to a high of $200.90 in 2021.

The CAGR of PSE&G's salaries, wages, pensions and benefits expense per employee over the 10-year period examined was negative 0.08 percent. The Electric Group's CAGR over the same period was 3.17 percent, while the Regional Group's was 2.60 percent. The New Jersey Group's CAGR was 1.75 percent, while the ROE Proxy Group's was 3.54 percent. Therefore, PSE&G's salaries, wages, pensions and benefits expense per employee decreased, while those of the Electric, Regional, New Jersey, and ROE groups increased over the years examined.

In 2022, PSE&G's salaries, wages, pensions, and benefits expense per employee of $119.24 was approximately 18 percent lower than the Electric Group mean; 12 percent lower than the Regional Group mean; 8 percent lower than the New Jersey Group mean; and 39 percent lower than the ROE Proxy Group mean.

Q. Is it a notable accomplishment that PSE&G's salaries, wages, pensions, and benefits expenses, on a per employee basis is less than those of its peer companies?

A. Yes. Given that the Northeast traditionally has higher wages than most other parts of the country, I believe it is a notable accomplishment that PSE&G's salaries, wages, pensions, and benefits expenses per employee are below not only that of the Regional and New Jersey group means, but also that of the Electric Group, which includes companies across the country.

Q. How can you support the statement that wages in New Jersey are typically higher than those in most other regions of the country?

A. The Consumer Price Index ("CPI") for Urban Wage Earners and Clerical Workers, as reported by the United States Bureau of Labor Statistics ("BLS") sets forth statistics for the Northeast, Midwest, South and West. The following table presents the reported information as of December 31, 2022 by region:

Region	CPI-Urban Wage Earners and Clerical Workers	Ratio to Northeast
Northeast	305.734	1.000
Midwest	270.656	0.885
South	283.431	0.927
West	306.762	1.003

Q. Did you also compare PSE&G's total electric O&M expense to that of the peer groups?

A. Yes. Given that this is a distribution-only rate proceeding, for comparison purposes, I excluded both production and transmission O&M from the total O&M of each of the companies in the analyses.

Q. How did PSE&G's total O&M (excluding transmission and production expenses) per customer compare to that of the peer companies?

A. As shown on Schedule MJA-B-8, PSE&G's total O&M expense (excluding transmission and production) per customer ranged from a low of $300.34 in 2020 to a high of $397.25 in 2013. The Electric Group mean ranged from a low of $353.77 in 2013 to a high of $454.89 in 2022. The Regional Group mean ranged from a low of $376.45 in 2013 to a high of $473.73 in 2022. The New Jersey Group mean ranged from a low of $449.11 in 2013 to a high of $613.51 in 2020. The ROE Proxy Group mean ranged from a low of $488.76 in 2018 to a high of $548.69 in 2015. Therefore, total O&M expense (excluding transmission and production) per customer was consistently below (i.e., performed better than) the group means for each of the four comparison groups in all years except for 2013.

The CAGR of PSE&G's total O&M expense (excluding transmission and production) per customer over the 10-year period examined was a negative 2.01 percent. The Electric Group's CAGR over the same period was 2.83 percent, while the Regional Group's was 2.59 percent. The New Jersey Group's CAGR was 2.83 percent, while the ROE Proxy Group's was negative 0.48 percent. Therefore, PSE&G's total O&M expense (excluding transmission and production) per customer decreased more than the ROE group's did, while those of the Electric, Regional, and New Jersey groups increased over the years examined.

In 2022, PSE&G's total electric O&M (excluding transmission and production) per customer of $330.89 was approximately 30 percent lower than the Electric Group mean; 27 percent lower than the Regional Group mean; 43 percent lower than the New Jersey Group mean; and 36 percent lower than the ROE Proxy Group mean.

Q. Did the comparison of PSE&G's total O&M expenses (excluding transmission and production) per MWh sold basis produce similar results?

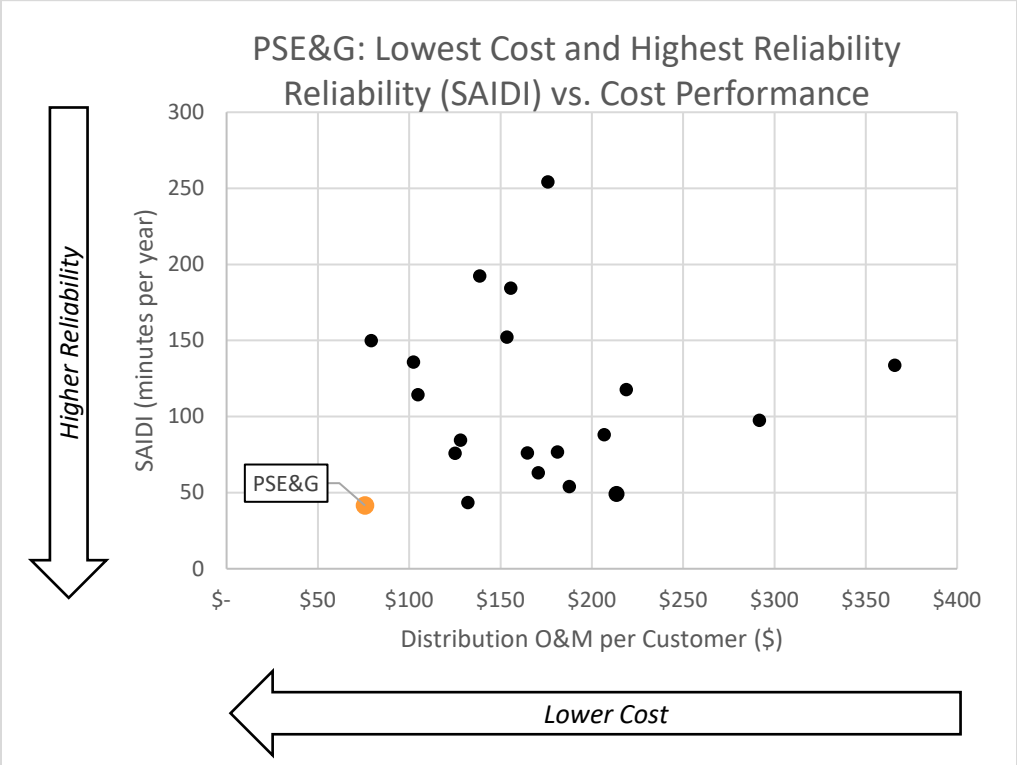
A. Yes. As shown on Schedule MJA-B-9, PSE&G's total electric O&M expenses (excluding transmission and production) per MWh sold ranged from a low of $17.33 in 2019 to a high of $21.11 in 2013. The Electric Group mean ranged from a low of $19.14 in 2013 to a high of $30.42 in 2022. The Regional Group mean ranged from a low of $19.86 in 2013 to a high of $27.63 in 2020. The New Jersey Group mean ranged from a low of $22.50 in 2013 to a high of $35.04 in 2020. The ROE Proxy Group mean ranged from a low of $25.94 in 2016 to a high of $34.67 in 2021. Therefore, PSE&G's total O&M expense (excluding transmission and production) per MWh sold was consistently below (i.e., performed better than) the group means for each of the four comparison groups in all years except for 2013.

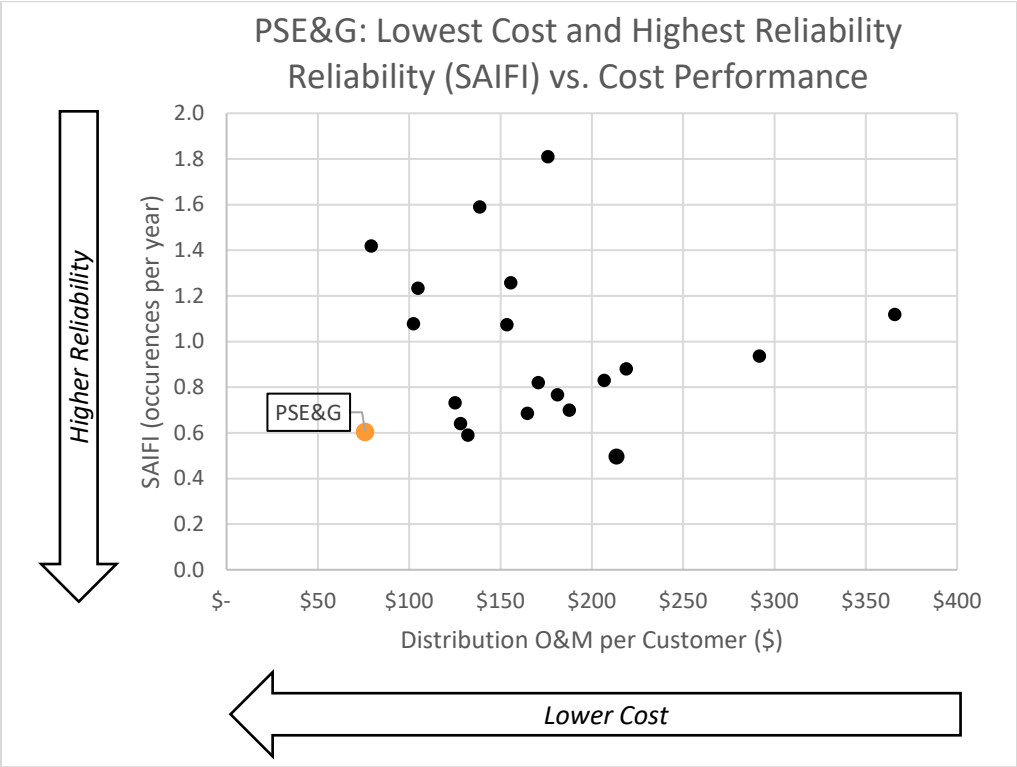
The CAGR of PSE&G's total electric O&M expenses (excluding transmission and production) per MWh over the 10-year period examined was negative 1.15 percent. The Electric Group's CAGR over the same period was 5.28 percent, while the Regional Group's was 3.65 percent. The New Jersey Group's CAGR was 4.03 percent, while the ROE Proxy Group's was 3.03 percent. Therefore, PSE&G's total O&M expense (excluding transmission and production) per MWh decreased, while those of the Electric, Regional, New Jersey, and ROE groups increased over the years examined.

In 2022, PSE&G's total electric O&M expenses (excluding transmission and production) per MWh sold of $19.02 was 37 percent lower than the Electric Group mean; 31 percent lower than the Regional Group mean; 41 percent lower than the New Jersey Group mean; and 44 percent lower than the ROE Proxy Group mean.

Q. Has the Company's reliability performance been negatively impacted as a result of the Company's cost control?

A. No, the Company has been able to manage its cost extremely well without compromising the system reliability. The charts below demonstrate that the Company is able to manage its costs while maintaining high levels of reliability compared to its peers. The reliability benchmarking is discussed in more detail later in my testimony.





IV. GAS BENCHMARKING ANALYSES

Q. Have you also benchmarked the performance of PSE&G's gas operations?

A. Yes, I have.

Q. What metrics did you use to evaluate the operational performance of PSE&G's gas business against that of its peer companies?

A. The following metrics were used to evaluate PSE&G's gas business performance against that of the peer groups:

1. Distribution O&M expense per gas customer;
2. Distribution O&M per Mcf sold;
3. A&G expense per gas customer;

4. A&G expense per Mcf sold;

5. Total Non-Production O&M expense per gas customer; and

6. Total Non-Production O&M expense per Mcf Sold.

Q. Prior to discussing the specific analyses that were prepared, can you discuss how PSE&G's gas business performed when benchmarked against its peer companies?

A. PSE&G's gas business was benchmarked against an LDC Group, a Regional Group, a New Jersey Group, and an ROE Proxy Group. PSE&G and the peer groups were evaluated based upon their respective performance over the most recent 10-year period for which data was publicly available. As will be discussed below, PSE&G's gas business performed well against each of the peer groups.

Q. For what years have you benchmarked PSE&G's gas business performance?

A. PSE&G's gas business performance was benchmarked against its peer companies for the years 2013 through 2022.

Q. How did PSE&G's gas business perform when compared to its peer companies on a distribution O&M expense per customer basis?

A. As shown on Schedule MJA-B-10, PSE&G's gas distribution O&M expense per customer was below (i.e., better than) the group mean for the LDC Group, Regional Group, and the ROE Proxy Group, in each year of the analysis. PSE&G's gas distribution O&M expense per customer was lower than the New Jersey Group mean for all but two years (2018 and 2019) of the ten years examined. PSE&G's gas distribution O&M per gas customer ranged from a low of $43.12 in 2013 to a high of $66.77 in 2018. The LDC Group mean ranged from a low of $74.13 in 2013 to a high of $99.88 in 2018. The Regional Group mean ranged from

a low of $85.68 in 2013 to a high of $129.18 in 2018. The New Jersey Group mean for the gas companies ranged from a low of $48.86 in 2013 to a high of $69.87 in 2021. The ROE Proxy Group mean for the gas companies ranged from a low of $75.32 in 2013 to a high of $89.12 in 2022.

The CAGR of PSE&G's gas distribution O&M expenses per customer over the 10-year period examined was 2.59 percent. The LDC Group's CAGR over the same period was 3.03 percent, while the Regional Group's was 4.35 percent. The New Jersey Group's CAGR was 2.84 percent, while the ROE Proxy Group's was 1.89 percent. Therefore, PSE&G's gas distribution O&M expense per customer increased at a lower rate over the years examined than that of the LDC, Regional, and New Jersey peer groups, and higher than that of the ROE group.

In 2022, PSE&G's gas distribution O&M expense per customer of $54.29 was approximately 44 percent lower than the LDC Group mean; 57 percent lower than the Regional Group mean; 14 percent lower than the New Jersey Group mean; and 39 percent lower than the ROE Proxy Group mean.

Q. How did PSE&G perform when compared to the peer groups on a gas distribution expense per Mcf sold basis?

A. As shown on Schedule MJA-B-11, PSE&G's gas distribution O&M expense per Mcf sold was below (i.e., better than) the mean of each of the four comparison groups in every year of the analysis. PSE&G's gas distribution O&M expense per Mcf sold ranged from a low of $0.25 in 2014 to a high of $0.42 in 2019. The LDC Group mean ranged from a low of $0.48 in 2013 to a high of $0.64 in 2018. The Regional Group mean ranged from a low of $0.56 in 2013 to a high of $0.88 in 2021. The New Jersey Group mean ranged from a low of $0.35 in

2013 to a high of $0.62 in 2020. The ROE Proxy Group mean ranged from a low of $0.45 in 2013 to a high of $0.54 in 2016.

The CAGR of PSE&G's total gas distribution O&M expenses per Mcf sold over the 10-year period examined was 4.53 percent. The LDC Group's CAGR over the same period was 2.98 percent, while the Regional Group's was 4.71 percent. The New Jersey Group's CAGR was 4.67 percent, while the ROE Proxy Group's was 0.53 percent. Therefore, PSE&G's gas distribution O&M expense per Mcf increased at a higher rate than that of the LDC and ROE groups, and at a lower rate than that of the Regional and New Jersey groups.

In 2022, PSE&G's gas distribution O&M expense per Mcf sold of $0.38 was approximately 39 percent lower than the LDC Group mean; 55 percent lower than the Regional Group mean; 28 percent lower than the New Jersey Group mean; and 19 percent lower than the ROE Proxy Group mean.

Q. Did PSE&G compare well on an A&G expense per gas customer basis when compared to the peer groups?

A. Yes. As shown on Schedule MJA-B-12, PSE&G's A&G expense per gas customer was below (i.e., better than) the group mean for each of the four comparison groups in every year of the analysis. PSE&G's A&G expense per gas customer ranged from a low of $31.96 in 2014 to a high of $51.72 in 2022. The LDC Group mean ranged from a low of $63.50 in 2015 to a high of $91.48 in 2022. The Regional Group mean ranged from a low of $82.07 in 2015 to a high of $112.53 in 2022. The New Jersey Group mean ranged from a low of $93.94 in 2020 to a high of $146.50 in 2022. The ROE Proxy Group mean ranged from a low of $75.83 in 2015 to a high of $99.26 in 2022.

The CAGR of PSE&G's A&G expenses per customer over the 10-year period examined was 3.93 percent. The LDC Group's CAGR over the same period was 3.89 percent, while the Regional Group's was 3.55 percent. The New Jersey Group's CAGR was 4.98 percent, while the ROE Proxy Group's was 2.95 percent. Therefore, PSE&G's A&G expense per gas customer increased at a rate lower than that of the New Jersey group, and higher than that of the LDC, Regional, and ROE groups. In 2022, PSE&G's A&G expense per gas customer of $51.72 was approximately 43 percent lower than the LDC Group mean; 54 percent lower than the Regional Group mean; 65 percent lower than the New Jersey Group mean; and 48 percent lower than the ROE Proxy Group mean.

Q. How did PSE&G rank in the comparison of gas A&G expense per Mcf sold?

A. As shown on Schedule MJA-B-13, PSE&G's A&G expense per Mcf sold was below (i.e., better than) the group mean for each of the four comparison groups in every year of the analysis. PSE&G's A&G expense per Mcf sold ranged from a low of $0.17 in 2014 to a high of $0.37 in 2020. The LDC Group mean ranged from a low of $0.43 in 2013 to a high of $0.59 in 2020. The Regional Group mean ranged from a low of $0.52 in 2015 to a high of $0.76 in 2022. The New Jersey Group mean ranged from a low of $0.65 in 2014 to a high of $1.22 in 2022. The ROE Proxy Group mean ranged from $0.45 in 2013 to a high of $0.62 in 2020.

The CAGR of PSE&G's A&G expenses per Mcf sold over the 10-year period examined was 5.89 percent. The LDC Group's CAGR over the same period was 3.68 percent, while the Regional Group's was 4.00 percent. The New Jersey Group's CAGR was 7.21 percent, while the ROE Proxy Group's was 1.98 percent. Therefore, PSE&G's A&G expense per Mcf sold

increased at a rate lower than that of the New Jersey group, and higher than that of the LDC, Regional, and ROE groups.

In 2022, PSE&G's A&G expense per Mcf sold of $0.37 was approximately 38 percent lower than the LDC Group mean; 52 percent lower than the Regional Group mean; 70 percent lower than the New Jersey Group mean; and 32 percent lower than the ROE Proxy Group mean.

Q. How did PSE&G's total non-production O&M per gas customer compare to that of the peer companies?

A. As shown on Schedule MJA-B-14, PSE&G's total non-production O&M expense per gas customer ranged from a low of $181.89 in 2021 to a high of $277.07 in 2013. The LDC Group mean ranged from a low of $261.55 in 2013 to a high of $305.59 in 2022. The Regional Group mean ranged from a low of $325.59 in 2013 to a high of $385.67 in 2022. The New Jersey Group mean ranged from a low of $290.71 in 2018 to a high of $379.27 in 2022. The ROE Proxy Group mean ranged from a low of $251.75 in 2018 to a high of $278.15 in 2022.

The CAGR of PSE&G's total non-production gas O&M expense per customer over the 10-year period examined was negative 3.48 percent. The LDC Group's CAGR over the same period was 1.74 percent, while the Regional Group's was 1.90 percent. The New Jersey Group's CAGR was 2.49 percent, while the ROE Proxy Group's was 0.84 percent. Therefore, PSE&G's total non-production gas O&M expense per customer decreased over the years examined while the CAGR of each of the peer groups increased.

In 2022, PSE&G's total non-production O&M per gas customer of $201.47 was approximately 34 percent lower than LDC Group mean; 48 percent lower than the Regional

Group mean; 47 percent lower than the New Jersey Group mean; and 28 percent lower than the ROE Proxy Group mean.

Q. Did the comparison of PSE&G's total non-production O&M expenses per Mcf sold bases produce similar results?

A. Yes. As shown on Schedule MJA-B-15, PSE&G's total non-production O&M expenses per Mcf sold ranged from a low of $1.29 in 2021 to a high of $1.65 in 2013. The LDC Group mean ranged from a low of $1.74 in 2013 to a high of $2.05 in 2020. The Regional Group mean ranged from a low of $2.17 in 2013 to a high of $2.69 in 2020. The New Jersey Group mean ranged from a low of $2.13 in 2013 to a high of $3.17 in 2022. The ROE Proxy Group mean ranged from a low of $1.47 in 2022 to a high of $1.81 in 2020.

The CAGR of PSE&G's total non-production O&M expenses per Mcf over the 10-year period examined was negative 1.65 percent. The LDC Group's CAGR over the same period was 1.66 percent, while the Regional Group's was 2.16 percent. The New Jersey Group's CAGR was 4.53 percent, while the ROE Proxy Group's was negative 0.84 percent. Therefore, PSE&G's total non-production O&M expenses per Mcf decreased over the years examined. This decrease was greater than the ROE group decrease, while the CAGR for the LDC, Regional and New Jersey groups increased.

In 2022, PSE&G's total non-production O&M expenses per Mcf sold of $1.42 was approximately 29 percent lower than the LDC Group mean; 46 percent lower than the Regional Group mean; 55 percent lower than the New Jersey Group mean; and 3 percent lower than the ROE Proxy Group mean.

V. RELIABILITY

Q. Beyond PSE&G's financial performance, did you compare PSE&G's operational performance to that of other electric companies?

A. Yes. I reviewed PSE&G's reported System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") to those of the other New Jersey electric companies as reported to the EIA via Form 861 and reported to the IEEE via IEEE's annual benchmarking survey.

Q. What does the SAIDI metric represent?

A. SAIDI is the system average duration of interruptions that a customer would experience during a period, which in the case of the New Jersey data, reflects a calendar year.

Q. How did PSE&G's SAIDI performance compare to that of the other New Jersey electric companies?

A. As shown on Schedule MJA-B-16, for the years 2013 through 2022, PSE&G's reported SAIDI was consistently below (better than) that of the other New Jersey electric companies that reported comparable metrics. PSE&G's SAIDI ranged from 33.94 in 2022 to 55.10 in 2018. Atlantic City Electric Company's ("ACE") SAIDI ranged from 51.00 in 2022 to 135.00 in 2013 and Jersey Central Power & Light Company's ("JCP&L") SAIDI ranged from 101.70 in 2015 to 192.36 in 2021. Therefore, PSE&G's electric customers, on average, experienced interruptions of service of shorter durations than did the customers of the other New Jersey utilities.

Q. What does the SAIFI metric represent?

A. SAIFI is the average number of interruptions (i.e. frequency) that a customer would experience during a period, which in the case of the New Jersey data, reflects a calendar year.

Q. How did PSE&G's SAIFI performance compare to that of the other New Jersey electric companies?

A. As shown on Schedule MJA-B-17, for the years 2013 through 2022, PSE&G's reported SAIFI was consistently below (i.e., better than) that of the other New Jersey electric companies that reported comparable metrics. PSE&G's SAIFI ranged from 0.55 in 2022 to 0.79 in 2018. ACE's SAIFI ranged from 0.65 in 2022 to 1.45 in 2013 and JCP&L's SAIFI ranged from 1.09 in 2015 to 1.69 in 2020. Therefore, PSE&G's electric customers, on average, experienced interruptions of service less frequently than did the customers of the other New Jersey utilities.

Q. What does the CAIDI metric represent?

A. CAIDI measures the average restoration time during an outage for only customers who actually experienced an interruption and is most often reported in minutes.

Q. How did PSE&G's CAIDI performance compare to that of the other New Jersey electric companies?

A. As shown on Schedule MJA-B-18, for the years 2013 through 2022, PSE&G's reported CAIDI ranged from 60.39 in 2015 to 72.13 in 2020. ACE's CAIDI ranged from 75.69 in 2017 to 102.50 in 2014 and JCP&L's CAIDI ranged from 93.30 in 2015 to 122.12 in 2022. Based upon the reported figures, not only did PSE&G's customers experience fewer interruptions; if interruptions were experienced, PSE&G's customers' power was restored more quickly than the power of other companies' customers.

Q. Does the IEEE also collect and report data for SAIDI, SAIFI, and CAIDI of electric utilities in the United States?

A. Yes. The IEEE initiated a benchmarking study in 2003 and the study is conducted annually. Participants are anonymous and are identified by key identifier only, to retain anonymity. While the participation list is not revealed, each participant can choose to share its results.

Q. Have you compared PSE&G's performance to the IEEE's 2022 study results?

A. Yes.

Q. Please describe how PSE&G's SAIFI performance for the years 2013 to 2022 compared to data reported by the IEEE.

A. As shown on Schedule MJA-B-19, PSE&G's reported SAIFI was in the first quartile of all utilities' SAIFI reported to the IEEE during each of the years 2013 to 2022, indicating that, at the very least, PSE&G was in the top 25% of all utilities surveyed. PSE&G's SAIFI ranged from 0.55 in 2022 to 0.78 in 2018.

Q. Why are PSE&G's SAIFI figures reported in the IEEE study different than those reported to the EIA, as you discussed previously?

A. It is my understanding that the EIA and IEEE have different definitions regarding major events and how they are established and as a result, the SAIFI figures are different.

Q. Does the IEEE also report CAIDI figures?

A. Yes. As shown on Schedule MJA-B-20, PSE&G's reported CAIDI was again solidly in the first quartile when compared to the companies participating in the IEEE study. PSE&G's CAIDI ranged from 60.53 in 2015 to 72.06 in 2020.

Q. Does the IEEE study also benchmark utilities' System Average Interruption Duration Index ("SAIDI")?

A. Yes, it does.

Q. What is the difference between CAIDI and SAIDI?

A. CAIDI reports duration on a customer basis, SAIDI reports duration on a system-wide basis.

Q. How did PSE&G's SAIDI compare to the IEEE study participants?

A. As shown on Schedule MJA-B-21, PSE&G's SAIDI was also in the first quartile of metrics reported in the IEEE study for all years examined. PSE&G's SAIDI ranged from 33.94 in 2022 to 53.51 in 2018.

VI. CUSTOMER SATISFACTION

Q. What customer satisfaction information did you review?

A. J.D. Power conducts and reports the results of annual customer satisfaction surveys. PSE&G is included in J.D. Power's Customer Satisfaction Studies in the "Large Utility East" segment. J.D. Power conducts customer satisfaction surveys of (1) electric residential customers; (2) electric business customers; (3) gas residential customers; and (4) gas business customers.

Q. Based upon J.D. Power's reported results for the years 2013 through 2022, where did PSE&G rank, based upon the feedback from electric residential customers?

A. As shown on Schedule MJA-B-22, PSE&G was ranked in the first quartile in every year of the analysis, except for 2013 and 2014, where it ranked in the second quartile. In the

most recent results released by J.D. Power for the calendar year 2022, electric residential customers ranked PSEG in the first quartile (and first overall) with a rating of 767.

Q. How did PSE&G rank based upon J.D. Power's survey of its electric business customers during the years 2012 through 2022?

A. As shown on Schedule MJA-B-23, PSE&G was ranked in the first or second quartile by its electric business customers during each of the years 2013 through 2022. PSE&G was ranked in the first quartile (and second overall) by its electric business customers in the most recent survey, i.e., 2022.

Q. Based upon J.D. Power's reported results for the years 2013 through 2022, where did PSE&G rank based upon the feedback from its gas residential customers?

A. As shown on Schedule MJA-B-24, PSE&G was ranked in the first or second quartile by its gas residential customers in each of the years 2013 through 2022. It should also be noted that PSE&G's gas residential customer satisfaction rating improved year-over-year for nine straight years, from 2014 to 2022. In the most recent results released by J.D. Power for the calendar year 2022, gas residential customers ranked PSEG in the first quartile (and first overall) with a rating of 770.

Q. How did PSE&G rank based upon J.D. Power's survey of its gas business customers during the years 2013 through 2022?

A. As shown on Schedule MJA-B-25, PSE&G's gas business customer satisfaction rating improved year-over-year each year from 2019 to 2021, and was ranked in the first quartile (and third overall) in 2022.

VII. SUMMARY AND CONCLUSIONS

Q. What are your conclusions based upon the analyses that you prepared?

A. PSE&G's O&M costs of the gas and electric businesses compare favorably to those of peer group averages. PSEG's ability to control costs, with some cost items having a negative CAGR over the period examined, is remarkable. Similarly, PSE&G's reliability and customer satisfaction scores indicate strong performance and a focus on improvement.

Given PSE&G's strong performance, as set forth in my testimony, I am recommending that the results of the benchmarking analyses be considered by Company witness Ann Bulkley when establishing her recommended range of return on equity values for PSE&G's electric and gas businesses. In my opinion, it is appropriate for the BPU to set PSE&G's ROE at the upper end of Ms. Bulkley's range of return on equity in recognition of the Company's consistently strong cost control, operational performance, service quality and customer satisfaction performance. Therefore, I recommend that PSE&G's authorized return on equity be established at a level that reflects PSE&G's strong performance and cost management in an operating environment where costs tend to be higher.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MICHAEL J. ADAMS
SENIOR VICE PRESIDENT

Mr. Adams has over thirty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry.

While employed by Illinois Power Company, Mr. Adams monitored project expenditures associated with gas and electric distribution, transmission, and generation capital projects.

While employed by the Illinois Commerce Commission, Mr. Adams initially evaluated the rate filings of regulated utilities and provided expert testimony regarding the reasonableness of the requests. Mr. Adams was subsequently charged with developing and managing a management and operations audit program to evaluate company management policies, procedures, and performance, as well as operational efficiency and effectiveness. Mr. Adams served as the Deputy Executive Director of the agency at the time of his departure. As a consultant, Mr. Adams has provided consulting services to regulatory agencies and regulated utilities on an array of operational and financial issues since 1995.

Prior to joining Concentric, Mr. Adams was a Managing Director of Navigant Consulting, Inc. Mr. Adams is a Certified Public Accountant, a graduate of Illinois College and holds an M.B.A. from the University of Illinois, Springfield.

Mr. Adams provides financial, regulatory, strategic, operational and litigation support to his energy clients. He has assisted clients with regulatory/legislative initiatives related to the approval and implementation of alternative regulation plans as well as the preparation and support of regulatory filings under alternative rate plans. Mr. Adams also provides advisory services in the areas of mergers and acquisitions. As a consultant, Mr. Adams has provided expert testimony or reports before State and Federal regulatory agencies.

REPRESENTATIVE PROJECT EXPERIENCE

Audits/Special Studies

- Management audits
- Regulatory reviews/audits

- Project performance monitoring/reviews
- Prudence reviews
- Commission ordered studies
- Audit prep and support
- Project controls and assessments

Affiliate Transactions

- Code of Conduct
- Shared Services reviews
- Cost controls

Benchmarking

- O&M costs
- Capital expenditures
- Shared Services
- Operational performance
- Customer service
- Reliability

Due Diligence/Litigation/Special Projects

- Assessment of cost controls
- Financial outlook
- Historical/future performance assessment
- Merger Synergies
- Regulatory environment/assessment

Expert Witness

- Regulatory proceedings
- Civil litigation

Litigation Support

- Data review and analyses
- Position development and review
- Research
- Expert testimony and reports

Regulatory Proceedings

- Revenue Requirement
- Cash working capital
- Benchmarking
  - O&M
  - Capital
  - Shared Services
- Case development/management
- Multi-year rate plans
- Research
- Performance based regulation

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2007 – Present)
Senior Vice President
Vice President

Navigant Consulting, Inc. (1999 – 2007)
Managing Director

L.E. Burgess Consultants, Inc. (1995 – 1999)

Illinois Commerce Commission (1983 – 1995)
Accounting/Rate Case Staff
Director, Management Audit/Studies
Deputy Executive Director

Illinois Power Company (1981 – 1983)
Accounting/Auditing Department

EDUCATION

University of Illinois at Springfield
M.B.A., Finance

Illinois College
B.S., Accounting

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant
American Institute of Public Accountants
Illinois Society of Certified Public Accountants

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Liberty Utilities (Entrada Del Oro Sewer Company and Gold Canyon Sewer Company	2022	Liberty Utilities	SW-02519A-0235, SW-0362+A-21-0236, SW-04316A-21-0359	Indirect Overhead/Capitalization Rates
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2002	Arkansas Oklahoma Gas Corporation	02-024-U	Reasonableness of ratemaking Adjustments
CenterPoint Energy Arkla	2005	CenterPoint Energy Arkla	04-121-U	Cash Working Capital
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas	2013	Connecticut Natural Gas	13-06-08	Cash Working Capital
United Illuminating Company	2022	United Illuminating Company	22-08-08	Cash Working Capital
Federal Energy Regulatory Commission				
Granite State Gas Transmission	2010	Granite State Gas Transmission	RP10-896	Revenue Requirement
Georgia Public Service Commission				
Atlanta Gas Light Company	2019	Granite State Gas Transmission	42315	Cash Working Capital
Hawaii Public Utilities Commission				
Hawaii Electric Light Company, Inc.	2005	Hawaii Electric Light Company, Inc.	05-0315	Allowance for Funds Used During Construction
Idaho Public Utilities Commission				
Intermountain Gas Company	2016	Intermountain Gas Company	INT-G-16-2	Cash working capital, prepared/supported benchmarking for client

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Commerce Commission				
Illinois Power Company	1999	Illinois Power Company	99-0120/99-0134 (Cons.)	Functionalization/Unbundling of General and Intangible Assets and Administrative and General expenses.
Illinois Power Company	2004	Illinois Power Company	04-0476	Cash working capital and asset separation
Ameren Illinois Utilities	2006	Ameren Illinois Utilities	06-0070/06-0071/06-0072 (Cons.)	Functionalization of Assets, Cash Working Capital, Shared Services Costs, Benchmarking
Ameren Illinois Utilities	2007	Ameren Illinois Utilities	07-0585/07-0586/07-0587/ 07-0588/07-0589/07-0590 (Cons.)	Shared Services Costs, Asset Separation, Cash Working Capital
The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	2007	The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	07-0241/07-0242 (Cons.)	Cash working capital
Northern Illinois Gas Company	2008	Northern Illinois Gas Company	08-0363	Cash working capital
Ameren Illinois	2015	Ameren Illinois	16-0262	Benchmarking of Utility Performance
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0645	Rider ZEA Reconciliation
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0103	Rider PE Reconciliation
Nicor Gas	2023	Nicor Gas		Cash working capital
Commonwealth Edison Company	2023	Commonwealth Edison Company	TBD	Cash working capital
Ameren Illinois	2023	Ameren Illinois	TBD	Assessment of MYRP
Kentucky Public Service Commission				
Kentucky Power Company	2023	Kentucky Power Company	2023-00159	Cash working capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maine Public Utilities Commission				
Emera Maine	2017	Emera Maine	Docket No. 2017-00198	Cash working capital
Versant Power	2020	Versant Power	Docket No. 2020-00316	Cash working capital
Versant Power	2022	Versant Power	Docket No. 2022-00255	Cash working capital
Maryland Public Service Commission				
Constellation Energy	2009	Constellation Energy	Case No. 9173, Phase II	Shared Services, Benchmarking
Massachusetts Department of Public Utilities				
Massachusetts Distribution Companies	2002	Massachusetts Distribution Companies	DTE-99-84	Reliability standards and the appropriateness of utilizing data for benchmarking purposes
Missouri Public Service Commission				
AmerenUE (Union Electric Company)	2002	AmerenUE (Union Electric Company)	EC-2002-001	Cash working capital
AmerenUE	2003	AmerenUE	GR-2003-0517	Cash working capital
AmerenUE	2007	AmerenUE	ER-2007-0002	Cash working capital
AmerenUE	2008	AmerenUE	ER-2008-0318	Cash working capital
Missouri Gas Energy	2006	Missouri Gas Energy	GR-2006-0422	Cash working capital
Ameren Missouri Gas	2010	Ameren Missouri Gas	GR-2010-0363	Cash working capital
Ameren Missouri Electric	2010	Ameren Missouri Electric	ER-2011-0028	Cash working capital
Ameren Missouri	2012	Ameren Missouri	ER-2012-0166	Cash working capital
Ameren Missouri	2014	Ameren Missouri	ER-2014-0258	Affiliate transactions, Benchmarking

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Evergy Metro, Inc.	2022	Evergy Metro, Inc.	ER-2022-0129	Cash working capital, Property Tax Tracker
Evergy Missouri West, Inc.	2022	Evergy Missouri West, Inc.	ER-2022-0130	Cash working capital, Property Tax Tracker
Montana Public Service Commission				
Montana-Dakota Utilities	2022	Montana-Dakota Utilities	2022.11.XXXX	Cash working capital
New Hampshire Public Utilities Commission				
National Grid Energy North	2010	National Grid Energy North	DG 10-017	Revenue Requirement
New Mexico Public Regulation Commission				
New Mexico Gas Company	2019	New Mexico Gas Company	No. 19-00317-UT	Future Test Year Model / Revenue Requirement
State of New Jersey Board of Public Utilities				
PSEG	2018	PSEG	ER18010029 & GR18010030	Benchmarking
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	2003	Arkansas Oklahoma Gas Corporation	PUD200300088	Cash working capital
Ontario Energy Board				
Hydro One Distribution Business	2005	Hydro One Distribution Business	-	Cash working capital
Hydro One Transmission Business	2006	Hydro One Transmission Business	-	Cash working capital
Toronto Hydro	2006	Toronto Hydro	-	Cash working capital
Pennsylvania Public Utility Commission				
Allegheny Power	2004	Allegheny Power	M-00991220	Reliability data and reasonableness of established Standards
T.W. Phillips Gas and Oil Company, Inc.	2006	T.W. Phillips Gas and Oil Company, Inc.	R-00051178	Cash working capital
Tennessee Public Utility Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash working capital
Texas Public Utility Commission				
Texas-New Mexico Power Company	2008	Texas-New Mexico Power Company	36025	Revenue Requirement
El Paso Electric Company	2012	El Paso Electric Company	40094	O&M Benchmarking
El Paso Electric Company	2014	El Paso Electric Company	-	Benchmarking of New Generation Costs
El Paso Electric Company	2015	El Paso Electric Company	44941	Benchmarking of costs of new generation units
Virginia State Corporation Commission				
Virginia Natural Gas	2012	Virginia Natural Gas	PUE-2010-00142	Cash Working Capital
Virginia Natural Gas	2017	Virginia Natural Gas		Shared Services Review, Benchmarking, Cash Working Capital
Virginia Natural Gas	2022	Virginia Natural Gas	PUR-2022-00052	Cash working capital
West Virginia Public Service Commission				
Appalachian Power Company	2018	Appalachian Power Company	18-0646-E-42T	Cash working capital

Companies Included in Electric Comparisons

Operating Company	Electric Distribution	[1] Electric Group	[2] Regional Group	[3] New Jersey Group	[4] ROE Proxy Group	[5] ROE Proxy Company Parent Ticker
Ameren Illinois Company	IL	✓			✓	AEE
Atlantic City Electric Company	NJ	✓	✓	✓		
Baltimore Gas and Electric Company	MD	✓	✓			
Black Hills Colorado Electric, Inc.	CO				✓	BKH
CenterPoint Energy Houston Electric, LLC	TX	✓			✓	CNP
Commonwealth Edison Company	IL	✓				
Consolidated Edison Company of New York, Inc.	NY	✓	✓		✓	ED
Delmarva Power & Light Company	DE	✓	✓			
Duquesne Light Company	PA	✓	✓			
Jersey Central Power & Light Company	NJ	✓	✓	✓		
Massachusetts Electric Company	MA	✓				
Metropolitan Edison Company	PA	✓	✓			
New York State Electric & Gas Corporation	NY	✓	✓			
Niagara Mohawk Power Corporation	NY	✓	✓			
NSTAR Electric Company	MA	✓			✓	ES
Ohio Edison Company	OH	✓				
Oncor Electric Delivery Company LLC	TX	✓				
Orange and Rockland Utilities, Inc.	NJ				✓	ED
PECO Energy Company	PA	✓	✓			
Pennsylvania Electric Company	NY	✓	✓			
Potomac Electric Power Company	MD	✓	✓			
PPL Electric Utilities Corporation	PA	✓	✓			
Public Service Company of New Hampshire	NH	✓			✓	ES
Public Service Electric and Gas Company	NJ	✓	✓	✓	✓	PEG
Rockland Electric Company	NJ			✓	✓	ED
Sharyland Utilities, L.L.C.	TX				✓	SRE
The Cleveland Electric Illuminating Company	OH	✓				
The Connecticut Light and Power Company	CT	✓	✓		✓	ES
West Penn Power Company	PA	✓	✓			

[1] Electric Group includes all operating companies classified by SNL as "Electric Utility" or "Diversified Utility" which owned no regulated generation, and had a customer count of more than 500,000.

[2] Regional Group includes all companies in the "Electric Group" having electric distribution operations in Connecticut, Delaware, Maryland, New Jersey, New York, or Pennsylvania.

[3] New Jersey Group includes all companies with electric distribution operations in New Jersey.

[4] ROE Proxy Group includes all operating companies classified by SNL as "Electric Utility" or "Diversified Utility" which owned no regulated generation and are owned by the holding companies included in Company witness Bulkley's cost of capital recommendation.

Companies Included in Gas Comparisons

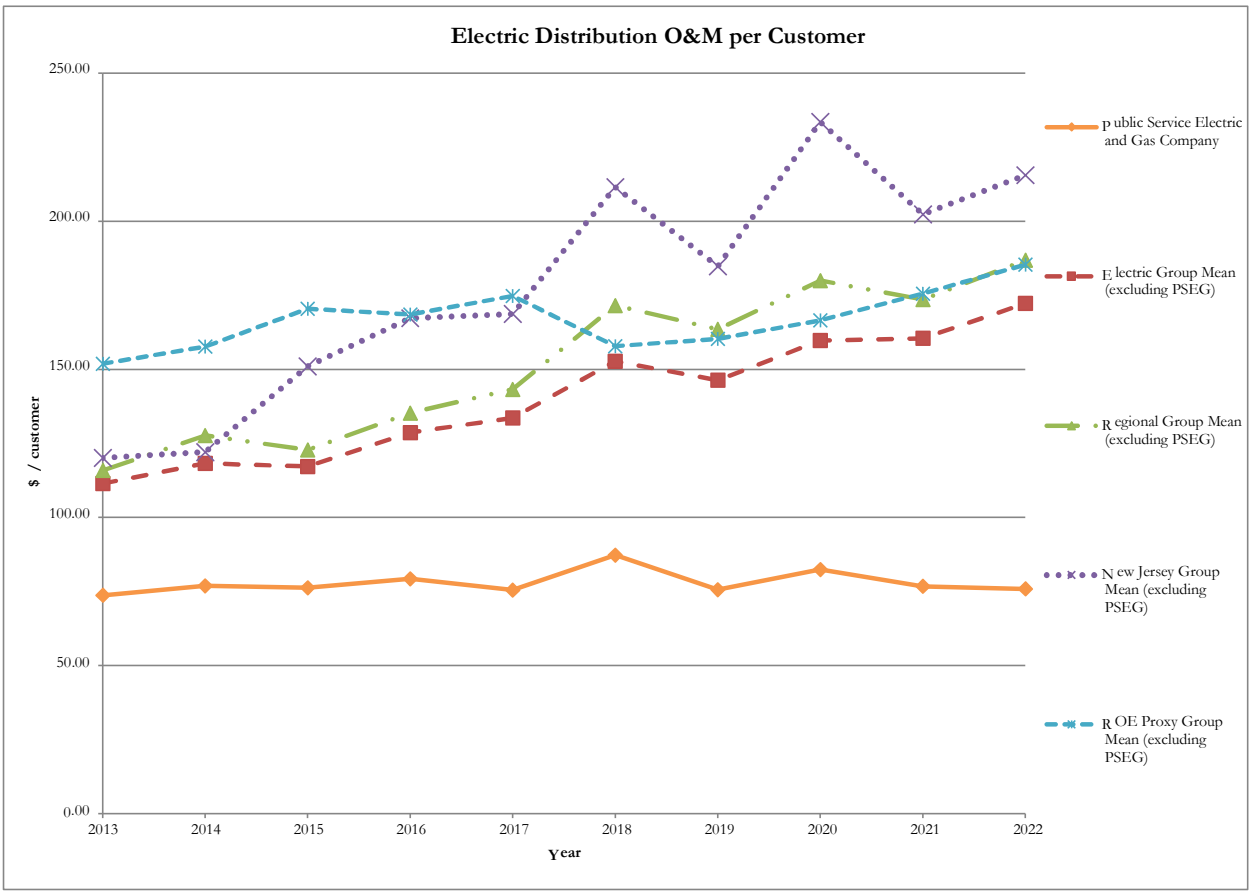
	[1]	[2]	[3]	[4]	[5]
Company	**LDC Group**	**Regional Group**	**New Jersey Group**	**ROE Proxy Group**	**ROE Proxy Company Parent Ticker**
Ameren Illinois Company - IL	✓			✓	AEE
Atlanta Gas Light Company - GA	✓			✓	SO
Avista Corporation - ID				✓	AVA
Avista Corporation - OR				✓	AVA
Avista Corporation - WA				✓	AVA
Baltimore Gas and Electric Company - MD	✓	✓			
Black Hills Colorado Gas, Inc. - CO				✓	BKH
Black Hills Energy Arkansas, Inc. - AR				✓	BKH
Black Hills Gas Distribution LLC - WY				✓	BKH
Black Hills Iowa Gas Utility Company, LLC - IA				✓	BKH
Black Hills Kansas Gas Utility Company, LLC - KS				✓	BKH
Black Hills Nebraska Gas, LLC - NE				✓	BKH
Boston Gas Company - MA	✓				
Brooklyn Union Gas Company - NY	✓	✓			
CenterPoint Energy Resources Corp. - TX	✓			✓	CNP
CenterPoint Energy Resources Corp. - MN	✓			✓	CNP
CenterPoint Energy Resources Corp. - AR				✓	CNP
CenterPoint Energy Resources Corp. - LA				✓	CNP
CenterPoint Energy Resources Corp. - OK				✓	CNP
CenterPoint Energy Resources Corp. - TX				✓	CNP
CenterPoint Energy Resources Corp. - LA				✓	CNP
CenterPoint Energy Resources Corp. - MS				✓	CNP
Chattanooga Gas Company - TN				✓	SO
Cheyenne Light, Fuel and Power Company - WY				✓	BKH
Columbia Gas of Ohio, Inc. - OH	✓				
Consolidated Edison Company of New York, Inc. - NY	✓	✓		✓	ED
Consumers Energy Company - MI	✓			✓	CMS
Dominion Energy, Inc. - UT	✓				
DTE Gas Company - MI	✓				
Elizabethtown Gas Company - NJ			✓		
Eversource Gas Company of Massachusetts - MA				✓	ES
Indiana Gas Company, Inc. - IN	✓			✓	CNP
Kansas Gas Service Company, Inc. - KS	✓				
KeySpan Gas East Corporation - NY	✓	✓			
Madison Gas and Electric Company - WI				✓	MGEE
Michigan Gas Utilities Corporation - MI				✓	WEC
MidAmerican Energy Company - IA	✓				
Minnesota Energy Resources Corporation - MN				✓	WEC
National Fuel Gas Distribution Corporation - NY	✓	✓			
New Jersey Natural Gas Company - NJ	✓	✓	✓		
New Mexico Gas Company, Inc. - NM	✓				
Niagara Mohawk Power Corporation - NY	✓	✓			
North Shore Gas Company - IL				✓	WEC
Northern Illinois Gas Company - IL	✓			✓	SO
Philadelphia Gas Works Co. - PA	✓	✓			
Piedmont Natural Gas Company, Inc. - NC	✓				
Public Service Company of Colorado - CO	✓			✓	XEL
Public Service Company of North Carolina, Incorporated - NC	✓				
Public Service Electric and Gas Company - NJ	✓	✓	✓		
Puget Sound Energy, Inc. - WA	✓				
San Diego Gas & Electric Company - CA	✓			✓	SRE
South Jersey Gas Company - NJ			✓		
Southern California Gas Company - CA	✓			✓	SRE
Southern Indiana Gas and Electric Company - IN				✓	CNP
Southwest Gas Corporation - NV	✓				
Spire Missouri Inc. - MO	✓				
Texas Gas Service Company, Inc. - TX	✓				
The East Ohio Gas Company - OH	✓				
The Peoples Gas Light and Coke Company - IL	✓			✓	WEC
UGI Utilities, Inc. - PA	✓	✓			
Vectren Energy Delivery of Ohio, Inc. - OH				✓	CNP
Virginia Natural Gas, Inc. - VA				✓	SO
Wisconsin Electric Power Company - WI	✓			✓	WEC
Wisconsin Gas LLC - WI	✓			✓	WEC
Yankee Gas Services Company - CT				✓	ES

[1] LDC Group includes all natural gas distribution companies with a customer count of more than 500,000.

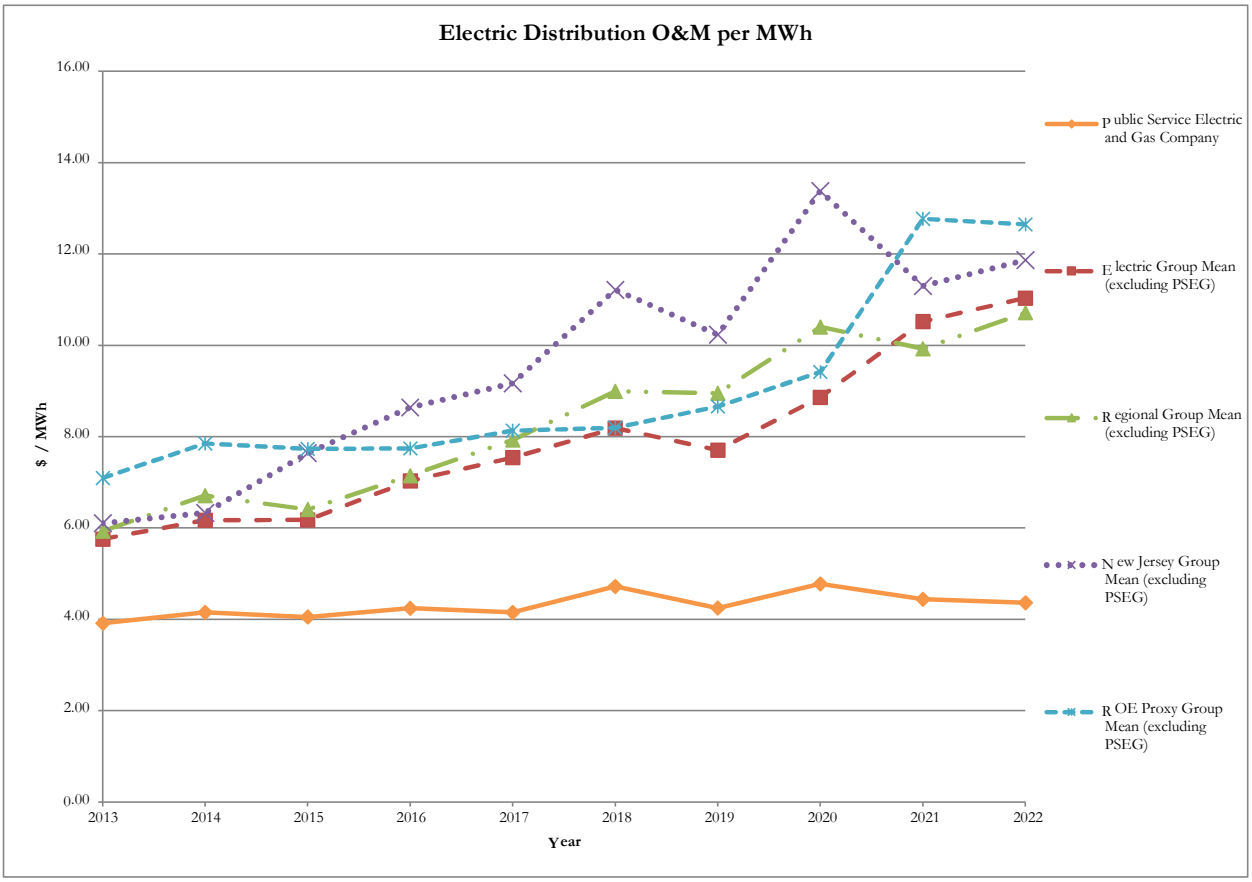
[2] Regional Group includes all companies in the "LDC Group" having natural gas distribution operations in Connecticut, Delaware, Maryland, New Jersey, New York, or Pennsylvania.

[3] New Jersey Group includes all companies with natural gas distribution operations in New Jersey.

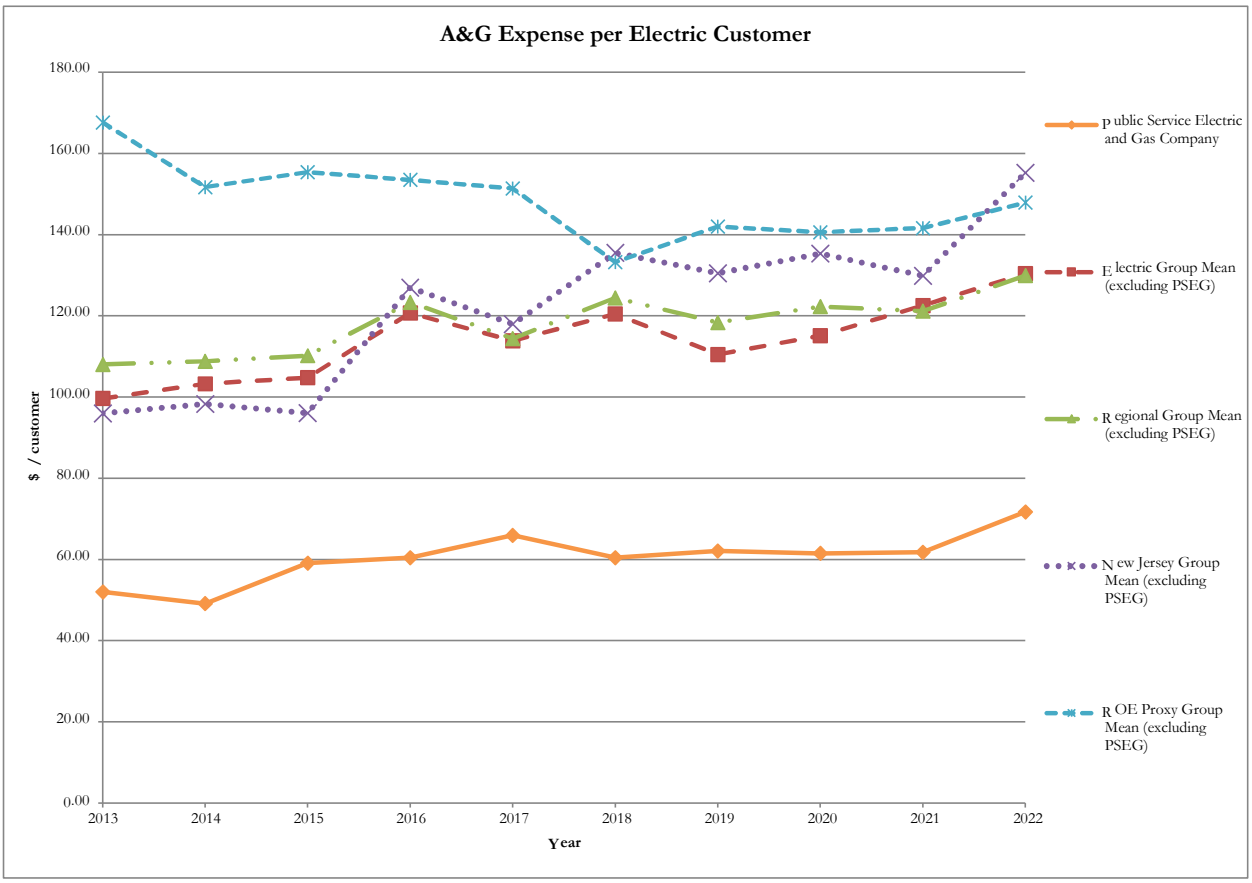
[4] ROE Proxy Group includes all natural gas distribution companies that are owned by the holding companies included in Company witness Bulkley's cost of capital recommendation.



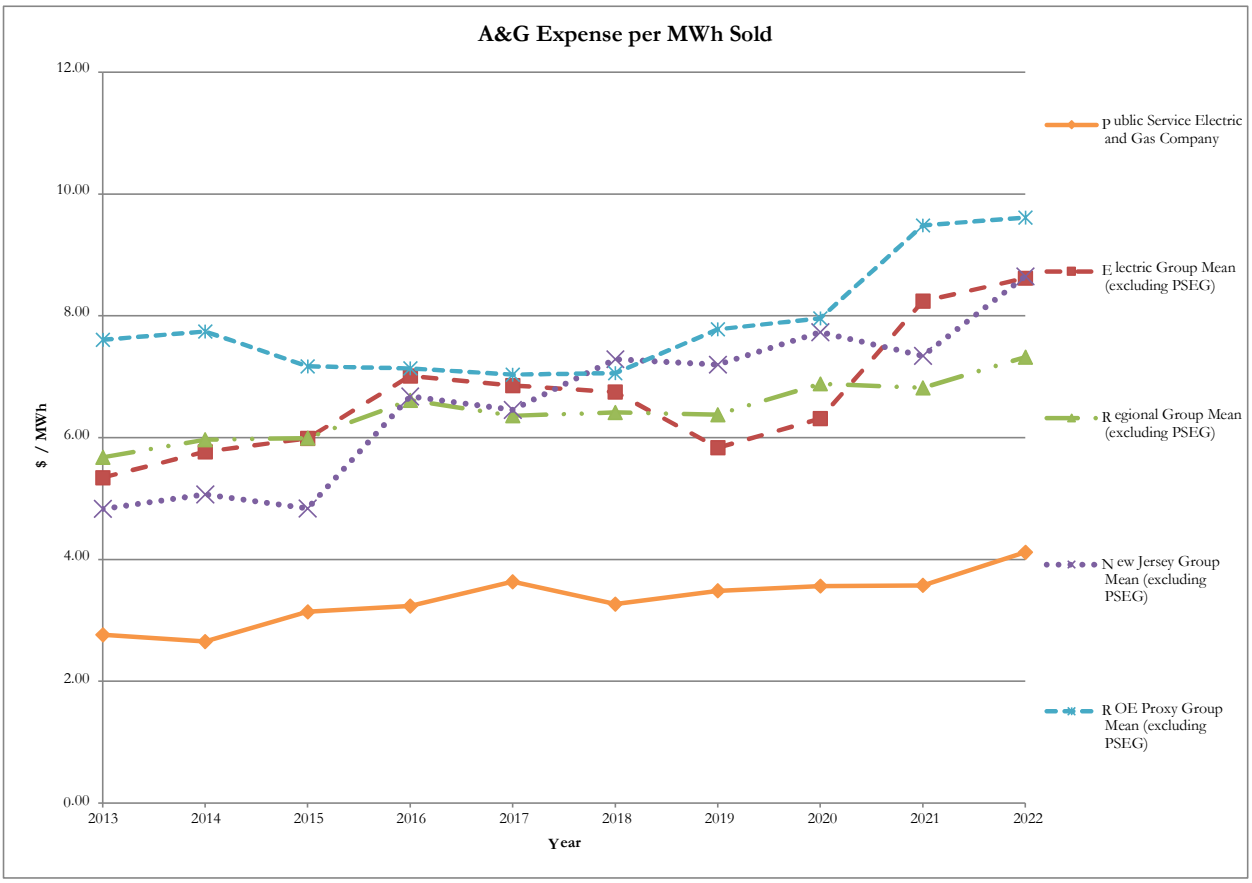
Electric Distribution O&M per Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	73.70	76.89	76.25	79.27	75.47	87.26	75.59	82.40	76.76	75.86
Electric Group Mean (excluding PSEG)	111.41	118.21	117.23	128.62	133.59	152.70	146.33	159.77	160.49	172.26
Regional Group Mean (excluding PSEG)	115.83	127.67	122.79	135.29	143.23	171.54	163.53	179.97	173.59	186.82
New Jersey Group Mean (excluding PSEG)	120.08	122.08	151.05	167.24	168.73	211.53	184.79	233.52	202.33	215.55
ROE Proxy Group Mean (excluding PSEG)	151.90	157.63	170.47	168.58	174.74	157.86	160.29	166.52	175.54	185.36



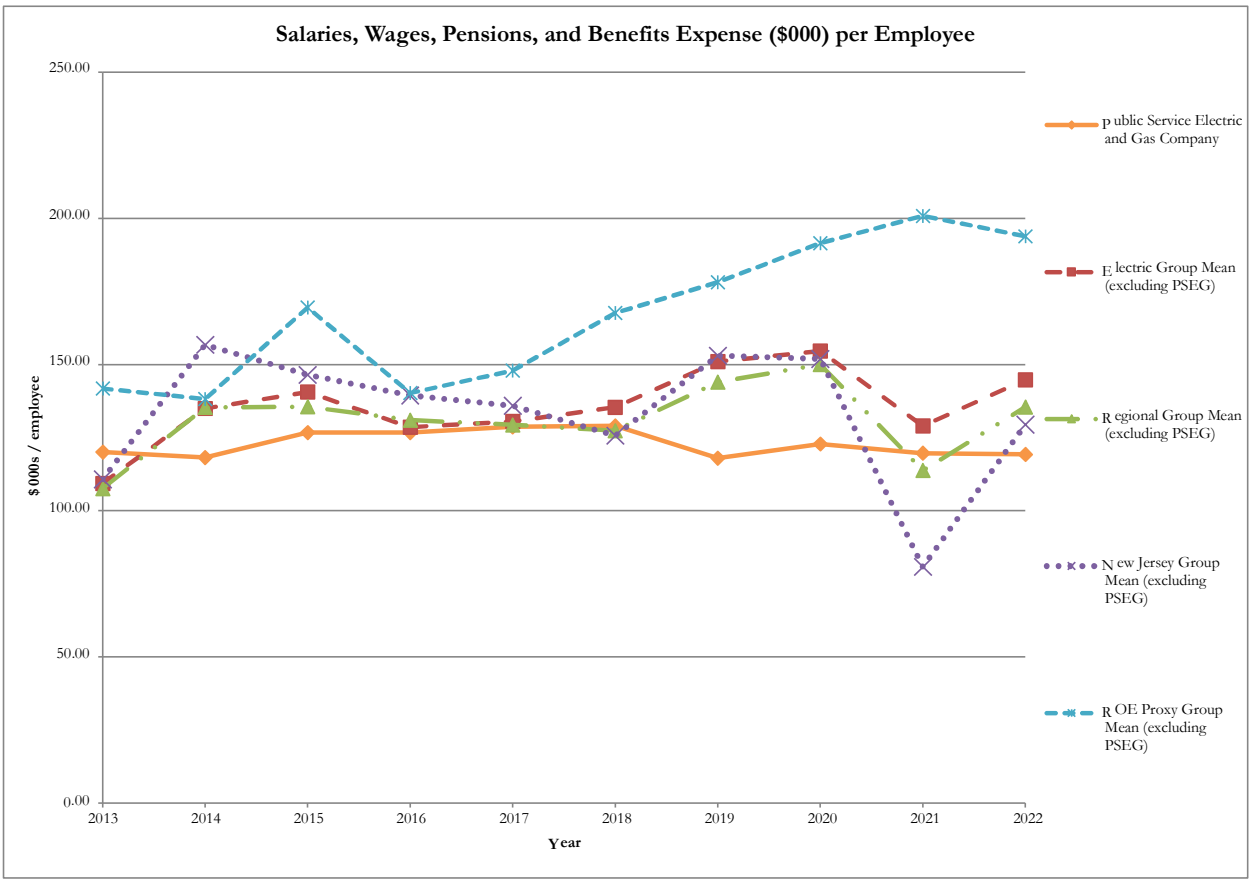
Electric Distribution O&M per MWh										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	3.92	4.15	4.05	4.24	4.16	4.72	4.25	4.78	4.44	4.36
Electric Group Mean (excluding PSEG)	5.76	6.17	6.18	7.03	7.54	8.19	7.71	8.86	10.52	11.04
Regional Group Mean (excluding PSEG)	5.93	6.71	6.41	7.14	7.93	8.99	8.95	10.40	9.93	10.71
New Jersey Group Mean (excluding PSEG)	6.10	6.33	7.64	8.64	9.17	11.22	10.23	13.38	11.30	11.86
ROE Proxy Group Mean (excluding PSEG)	7.09	7.85	7.73	7.74	8.13	8.19	8.66	9.42	12.77	12.65



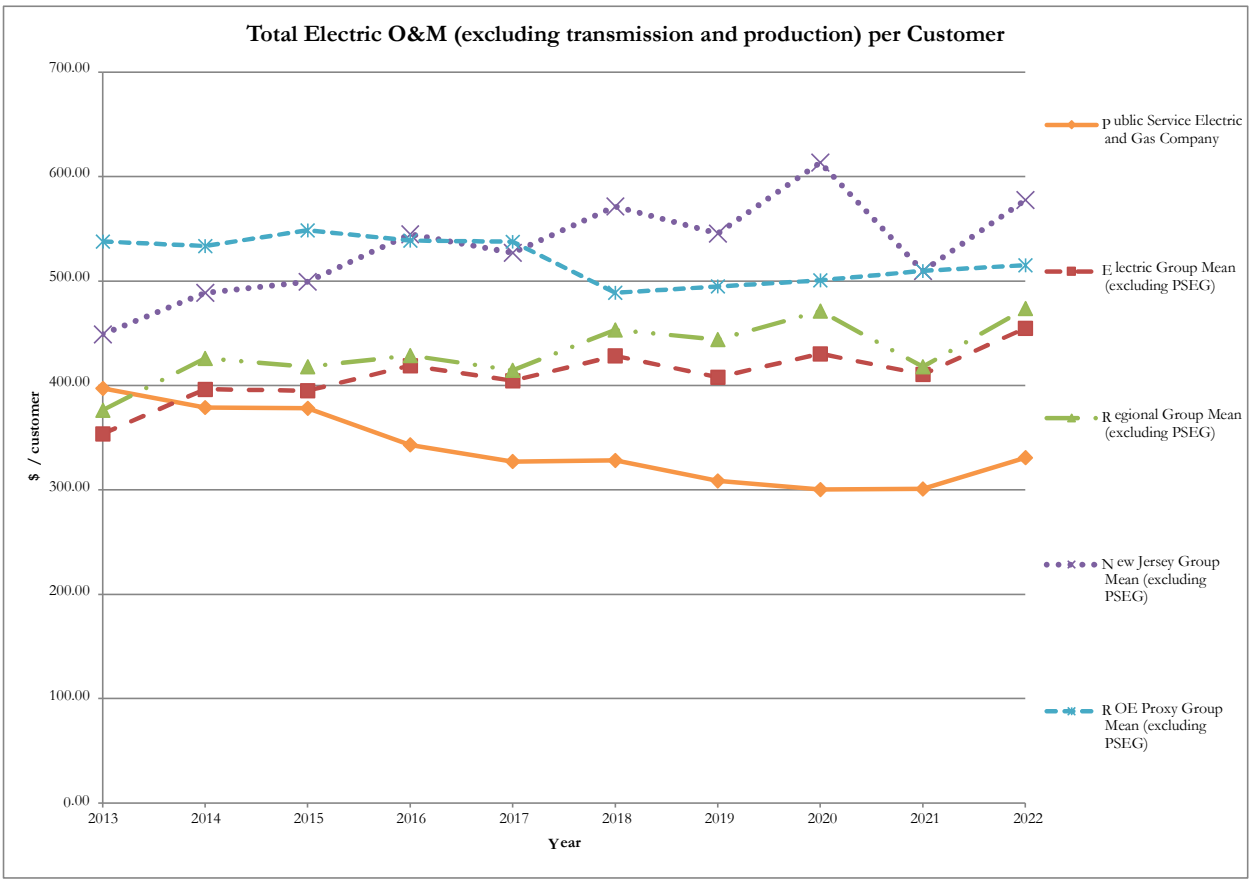
A&G Expense per Electric Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	51.96	49.12	59.11	60.45	65.95	60.43	62.07	61.50	61.76	71.69
Electric Group Mean (excluding PSEG)	99.62	103.25	104.79	120.69	113.89	120.46	110.52	115.11	122.57	130.43
Regional Group Mean (excluding PSEG)	108.05	108.80	110.19	123.33	114.40	124.44	118.38	122.29	121.15	129.92
New Jersey Group Mean (excluding PSEG)	95.99	98.32	96.02	126.96	117.99	135.53	130.50	135.37	129.84	155.25
ROE Proxy Group Mean (excluding PSEG)	167.66	151.74	155.44	153.47	151.40	133.23	141.99	140.60	141.65	147.90



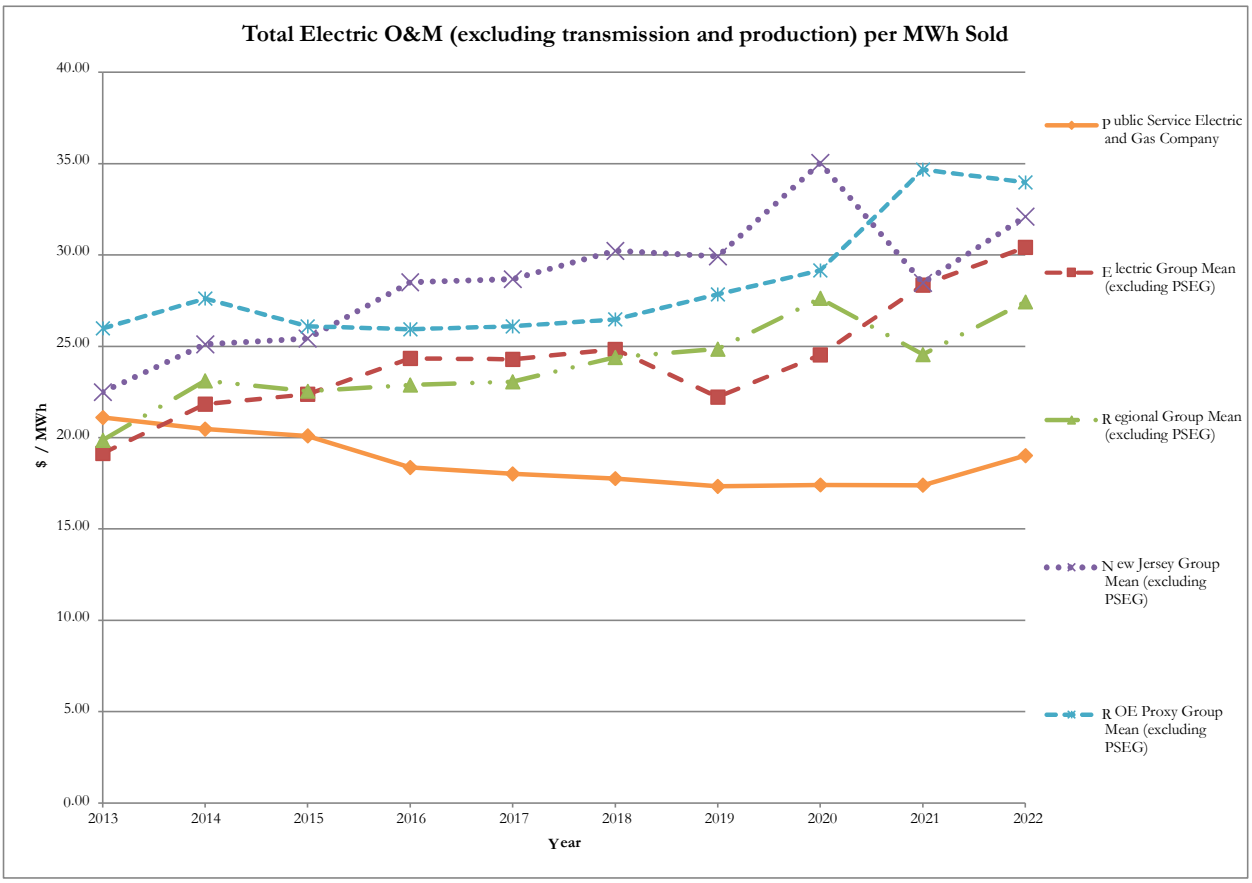
A&G Expense per MWh Sold										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	2.76	2.65	3.14	3.24	3.63	3.27	3.49	3.56	3.57	4.12
Electric Group Mean (excluding PSEG)	5.35	5.77	5.99	7.01	6.86	6.75	5.83	6.31	8.24	8.62
Regional Group Mean (excluding PSEG)	5.68	5.97	5.99	6.61	6.36	6.41	6.38	6.88	6.82	7.32
New Jersey Group Mean (excluding PSEG)	4.83	5.07	4.84	6.68	6.46	7.29	7.20	7.73	7.34	8.65
ROE Proxy Group Mean (excluding PSEG)	7.61	7.74	7.17	7.14	7.04	7.06	7.78	7.96	9.49	9.62



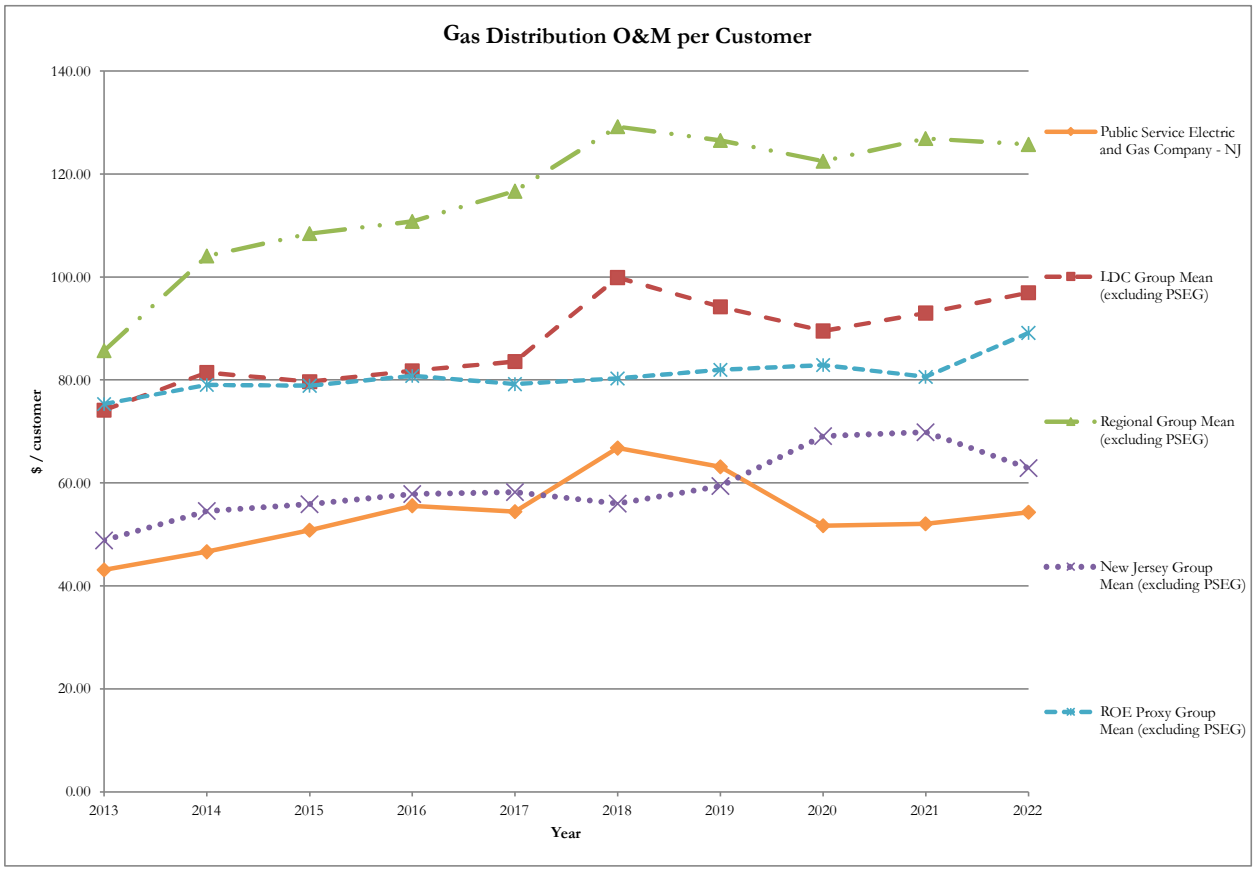
Salaries, Wages, Pensions, and Benefits Expense ($000) per Employee										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	120.12	118.26	126.71	126.74	128.67	129.04	117.95	122.80	119.68	119.24
Electric Group Mean (excluding PSEG)	109.34	134.98	140.62	128.56	130.56	135.37	151.02	154.64	128.99	144.76
Regional Group Mean (excluding PSEG)	107.60	135.32	135.53	131.06	129.43	127.36	143.96	150.04	113.77	135.51
New Jersey Group Mean (excluding PSEG)	110.76	156.76	146.54	139.46	135.85	125.70	153.08	151.93	80.79	129.47
ROE Proxy Group Mean (excluding PSEG)	141.78	138.21	169.55	140.25	147.94	167.68	178.20	191.54	200.90	193.90



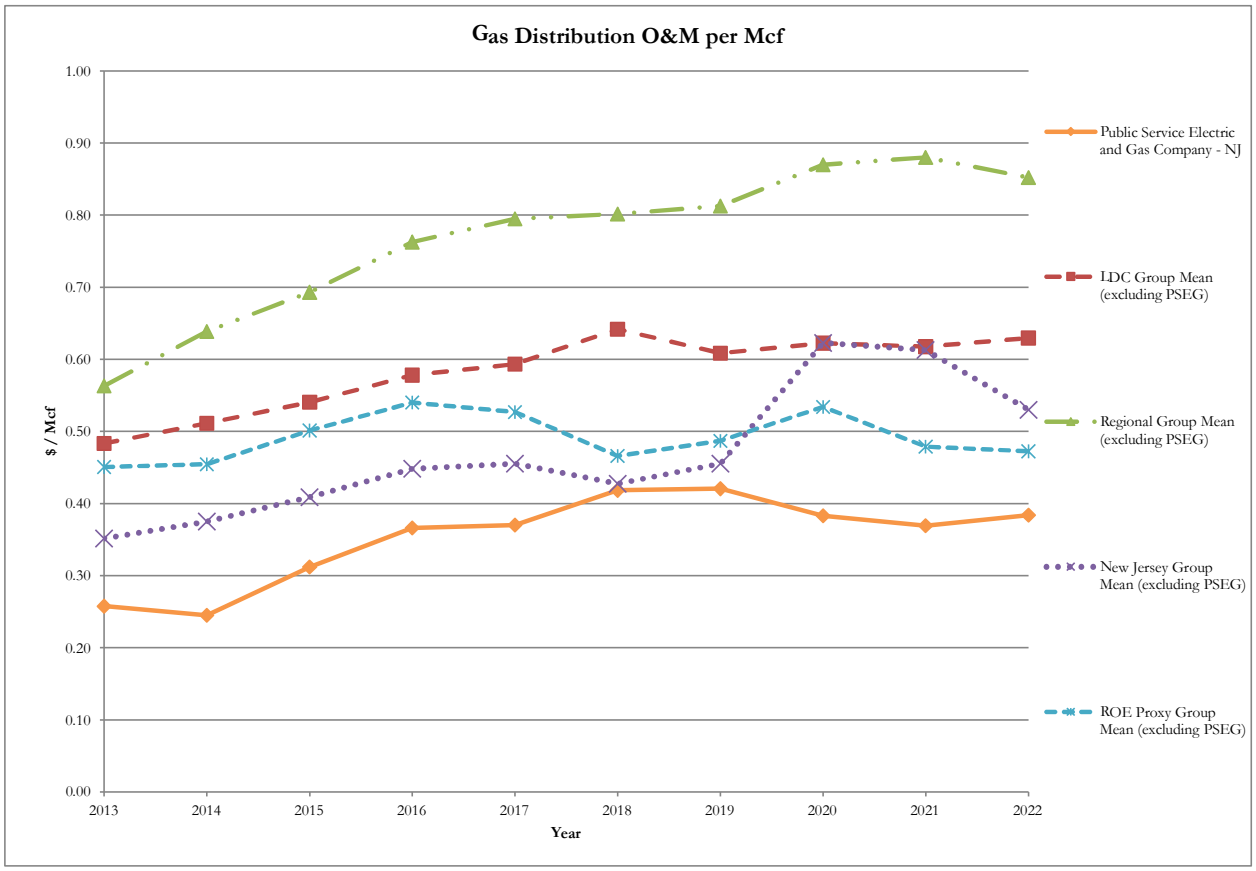
Total Electric O&M (excluding transmission and production) per Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	397.25	378.98	378.28	343.01	327.24	328.36	308.52	300.34	300.88	330.89
Electric Group Mean (excluding PSEG)	353.77	396.26	395.02	419.04	404.50	428.40	407.89	430.41	410.70	454.89
Regional Group Mean (excluding PSEG)	376.45	426.11	418.01	428.80	414.58	453.27	443.95	471.23	417.86	473.73
New Jersey Group Mean (excluding PSEG)	449.11	488.64	499.38	544.98	526.98	571.57	545.58	613.51	509.54	577.53
ROE Proxy Group Mean (excluding PSEG)	537.97	533.70	548.69	538.93	537.78	488.76	494.91	500.67	509.78	515.19



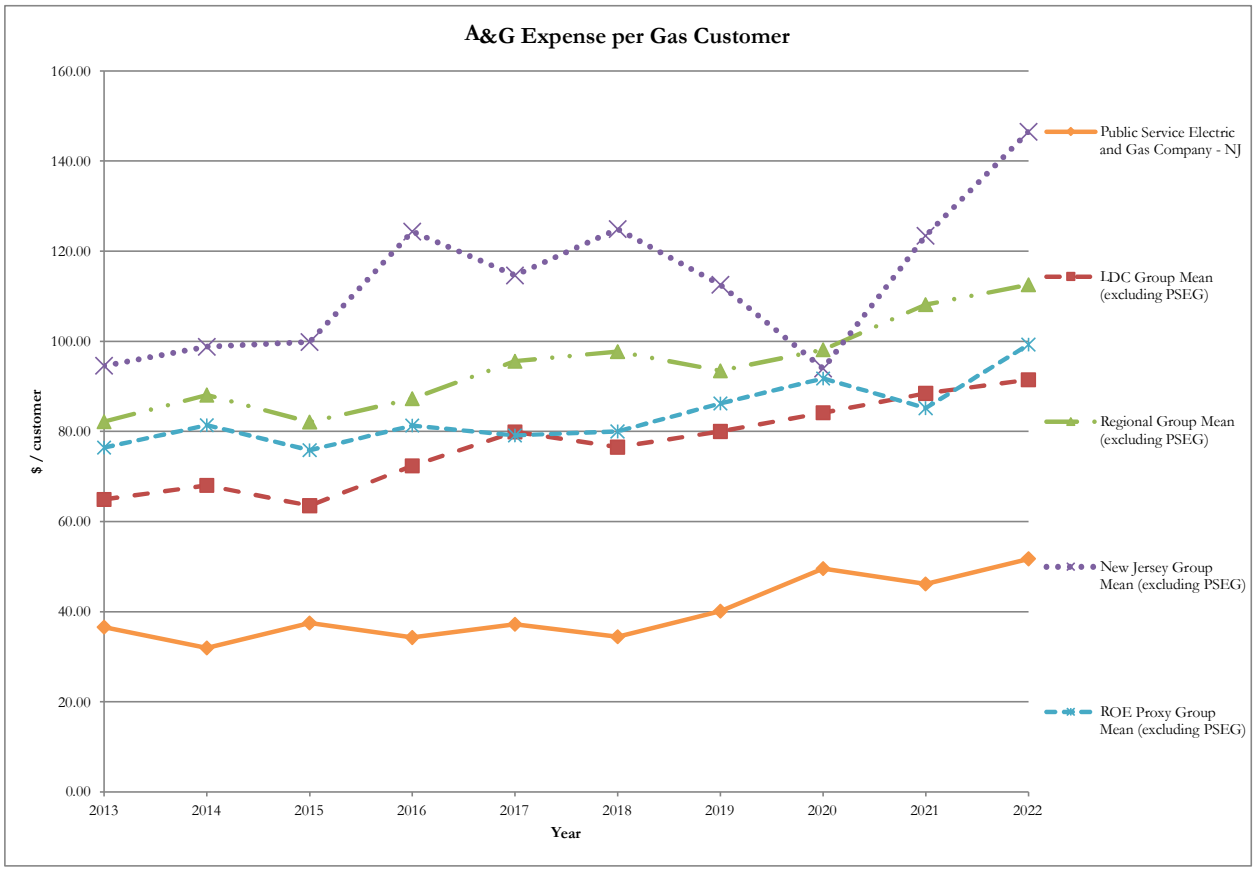
Total Electric O&M (excluding transmission and production) per MWh Sold										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	21.11	20.47	20.09	18.37	18.02	17.76	17.33	17.41	17.40	19.02
Electric Group Mean (excluding PSEG)	19.14	21.83	22.38	24.33	24.30	24.84	22.22	24.53	28.35	30.42
Regional Group Mean (excluding PSEG)	19.86	23.12	22.54	22.88	23.06	24.40	24.85	27.63	24.56	27.43
New Jersey Group Mean (excluding PSEG)	22.50	25.12	25.42	28.51	28.67	30.23	29.92	35.04	28.47	32.11
ROE Proxy Group Mean (excluding PSEG)	25.98	27.62	26.10	25.94	26.10	26.47	27.84	29.16	34.67	33.98



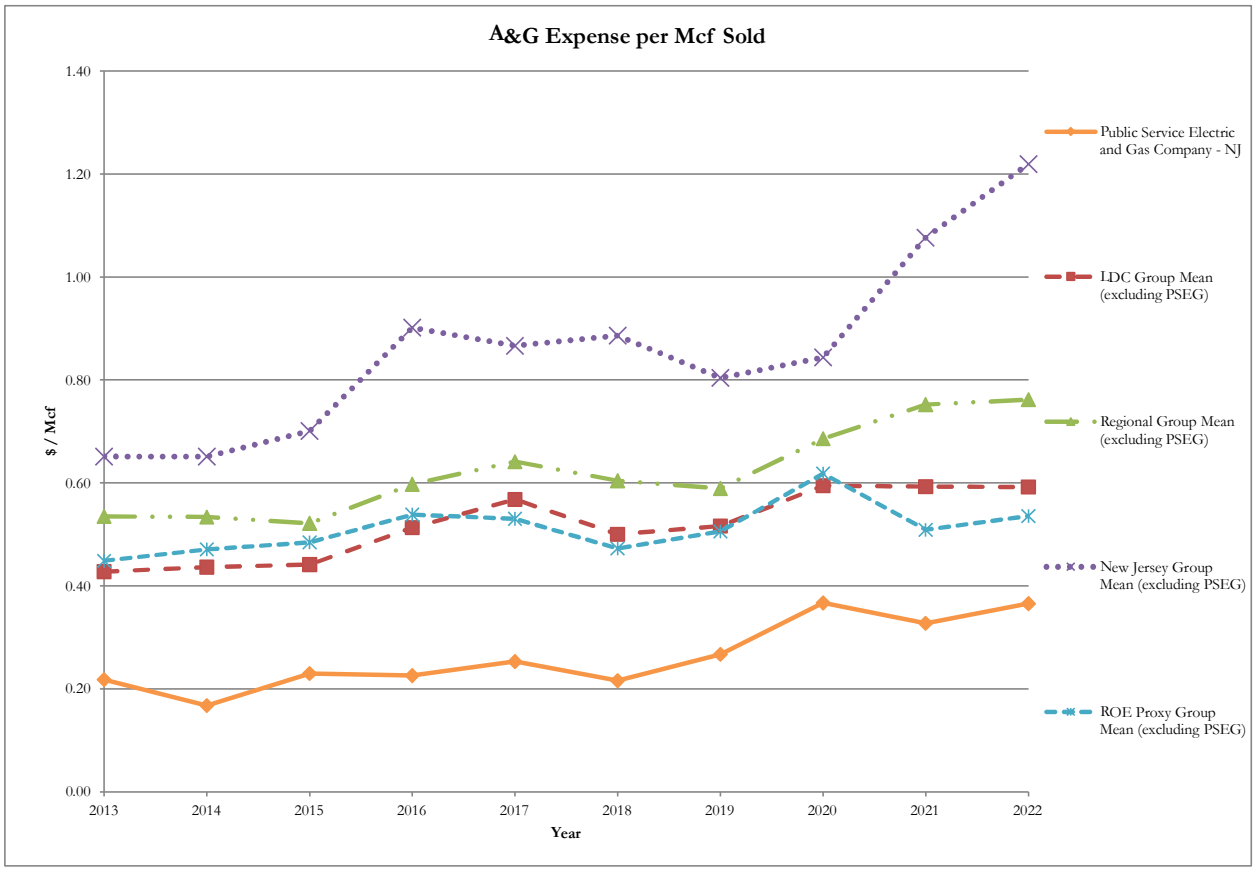
Gas Distribution O&M per Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	43.12	46.65	50.80	55.55	54.43	66.77	63.14	51.73	52.08	54.29
LDC Group Mean (excluding PSEG)	74.13	81.43	79.64	81.77	83.55	99.88	94.23	89.51	93.01	96.95
Regional Group Mean (excluding PSEG)	85.68	104.04	108.43	110.79	116.69	129.18	126.53	122.47	126.88	125.73
New Jersey Group Mean (excluding PSEG)	48.86	54.51	55.91	57.84	58.19	55.96	59.36	69.09	69.87	62.87
ROE Proxy Group Mean (excluding PSEG)	75.32	79.01	78.88	80.79	79.19	80.28	81.98	82.89	80.61	89.12



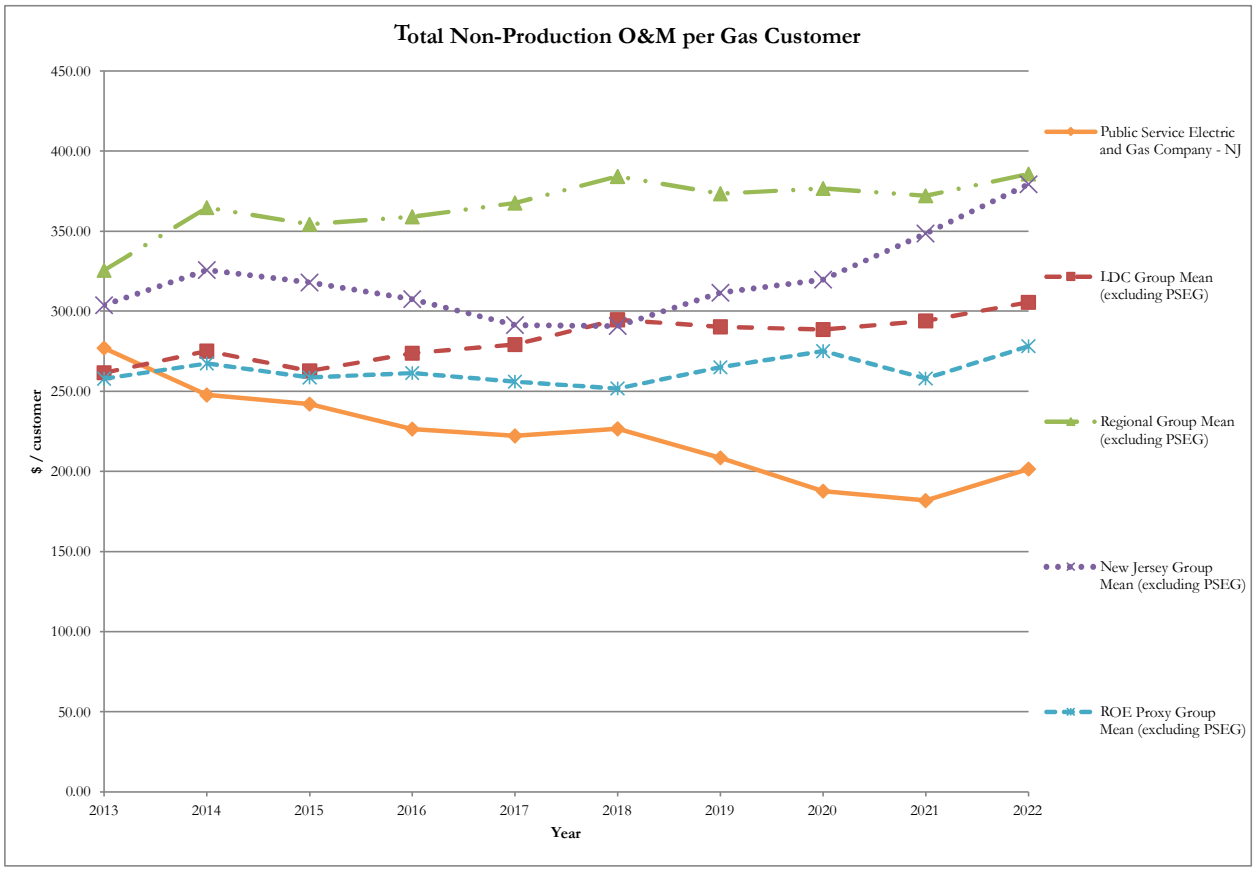
Gas Distribution O&M per Mcf										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	0.26	0.25	0.31	0.37	0.37	0.42	0.42	0.38	0.37	0.38
LDC Group Mean (excluding PSEG)	0.48	0.51	0.54	0.58	0.59	0.64	0.61	0.62	0.62	0.63
Regional Group Mean (excluding PSEG)	0.56	0.64	0.69	0.76	0.79	0.80	0.81	0.87	0.88	0.85
New Jersey Group Mean (excluding PSEG)	0.35	0.37	0.41	0.45	0.46	0.43	0.46	0.62	0.61	0.53
ROE Proxy Group Mean (excluding PSEG)	0.45	0.45	0.50	0.54	0.53	0.47	0.49	0.53	0.48	0.47



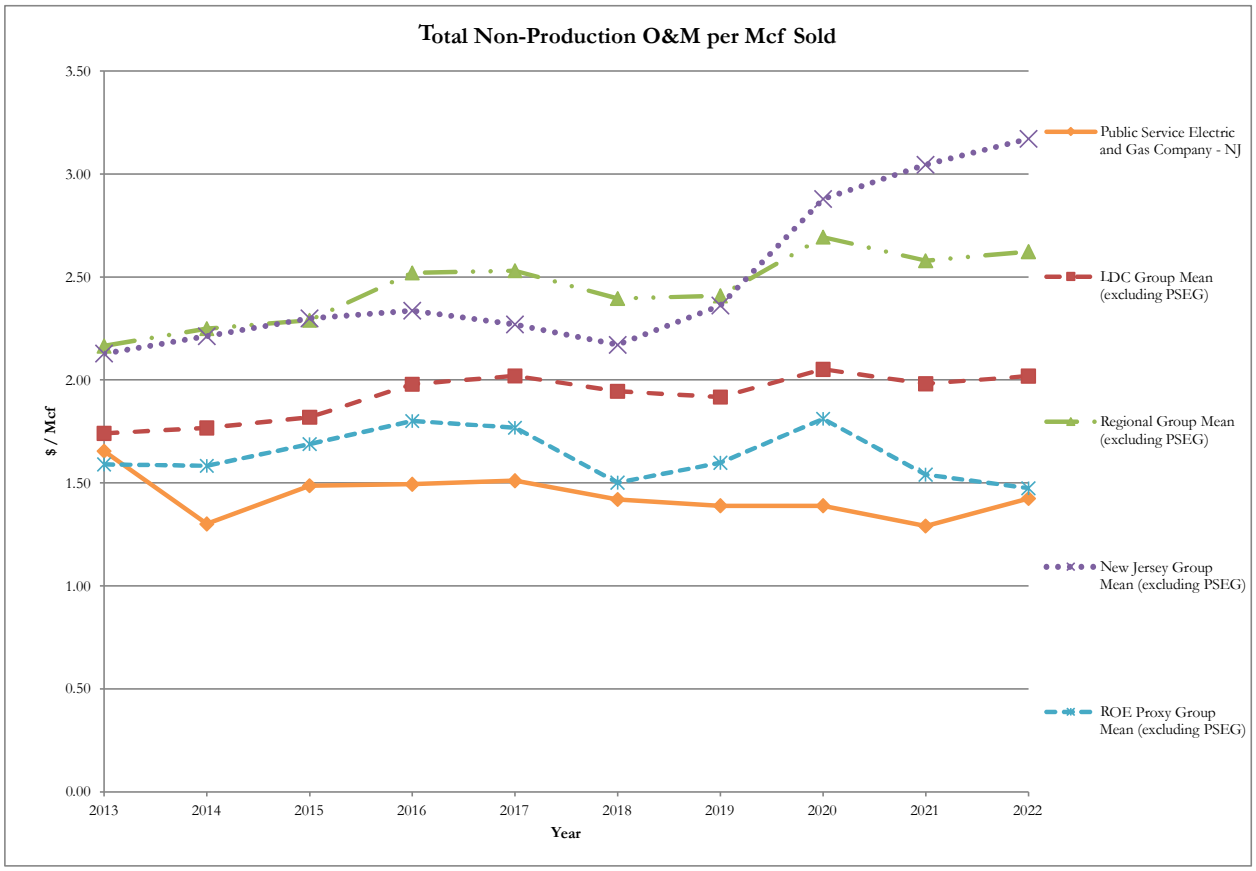
A&G Expense per Gas Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	36.57	31.96	37.47	34.28	37.25	34.45	40.13	49.59	46.16	51.72
LDC Group Mean (excluding PSEG)	64.91	68.02	63.50	72.40	79.90	76.54	79.99	84.16	88.45	91.48
Regional Group Mean (excluding PSEG)	82.17	88.10	82.07	87.25	95.61	97.73	93.45	98.14	108.13	112.53
New Jersey Group Mean (excluding PSEG)	94.56	98.79	99.84	124.39	114.61	124.87	112.57	93.94	123.42	146.50
ROE Proxy Group Mean (excluding PSEG)	76.43	81.39	75.83	81.28	79.13	80.02	86.22	91.76	85.16	99.26



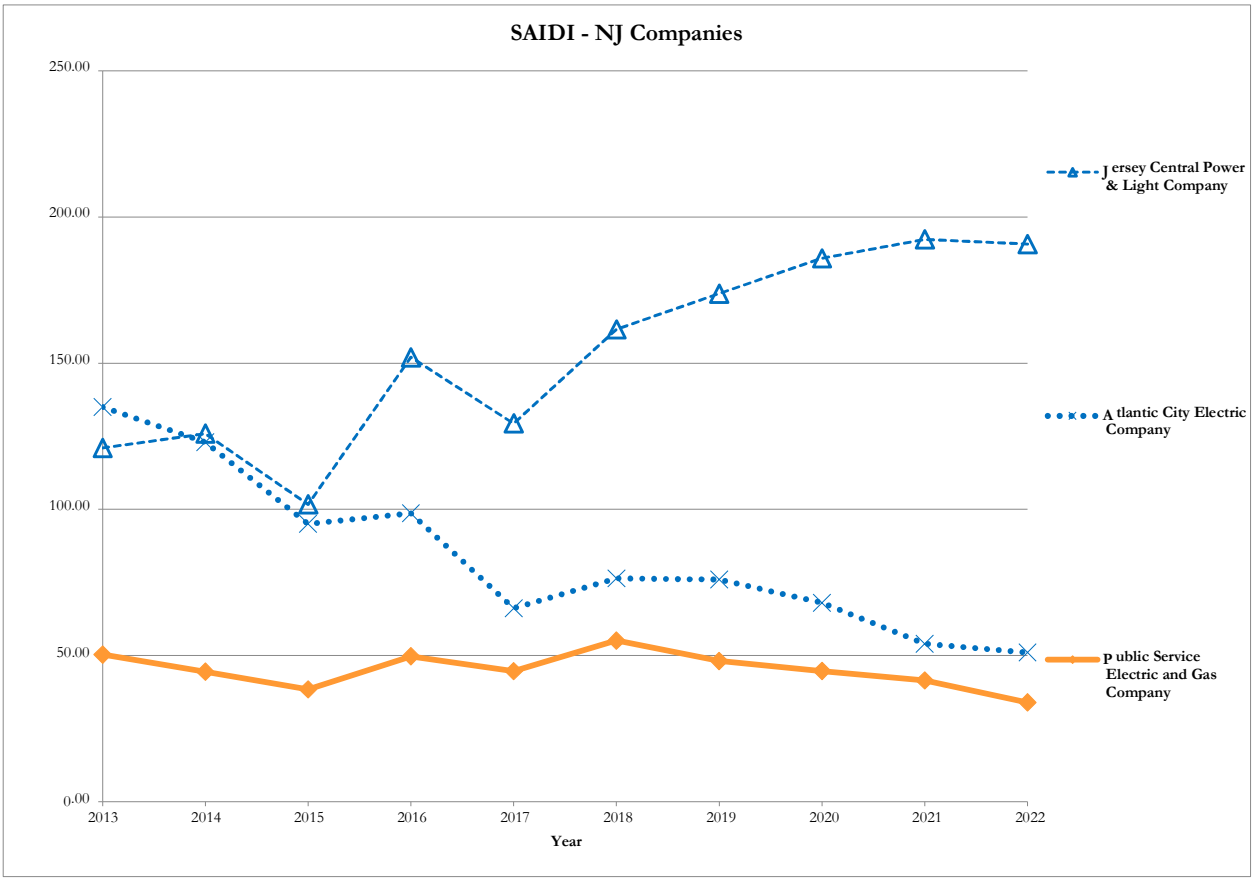
A&G Expense per Mcf Sold										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	0.22	0.17	0.23	0.23	0.25	0.22	0.27	0.37	0.33	0.37
LDC Group Mean (excluding PSEG)	0.43	0.44	0.44	0.51	0.57	0.50	0.52	0.59	0.59	0.59
Regional Group Mean (excluding PSEG)	0.54	0.53	0.52	0.60	0.64	0.60	0.59	0.69	0.75	0.76
New Jersey Group Mean (excluding PSEG)	0.65	0.65	0.70	0.90	0.87	0.89	0.80	0.84	1.08	1.22
ROE Proxy Group Mean (excluding PSEG)	0.45	0.47	0.48	0.54	0.53	0.47	0.51	0.62	0.51	0.54



Total Non-Production O&M per Gas Customer										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	277.07	247.70	242.08	226.49	222.23	226.54	208.58	187.78	181.89	201.47
LDC Group Mean (excluding PSEG)	261.55	275.07	262.81	273.81	279.21	294.70	290.28	288.49	293.90	305.59
Regional Group Mean (excluding PSEG)	325.59	364.70	354.32	358.91	367.65	384.25	373.38	376.61	372.16	385.67
New Jersey Group Mean (excluding PSEG)	303.88	325.69	318.01	307.57	291.34	290.71	311.52	319.82	348.45	379.27
ROE Proxy Group Mean (excluding PSEG)	257.98	267.34	258.66	261.39	256.06	251.75	265.06	275.20	258.15	278.15

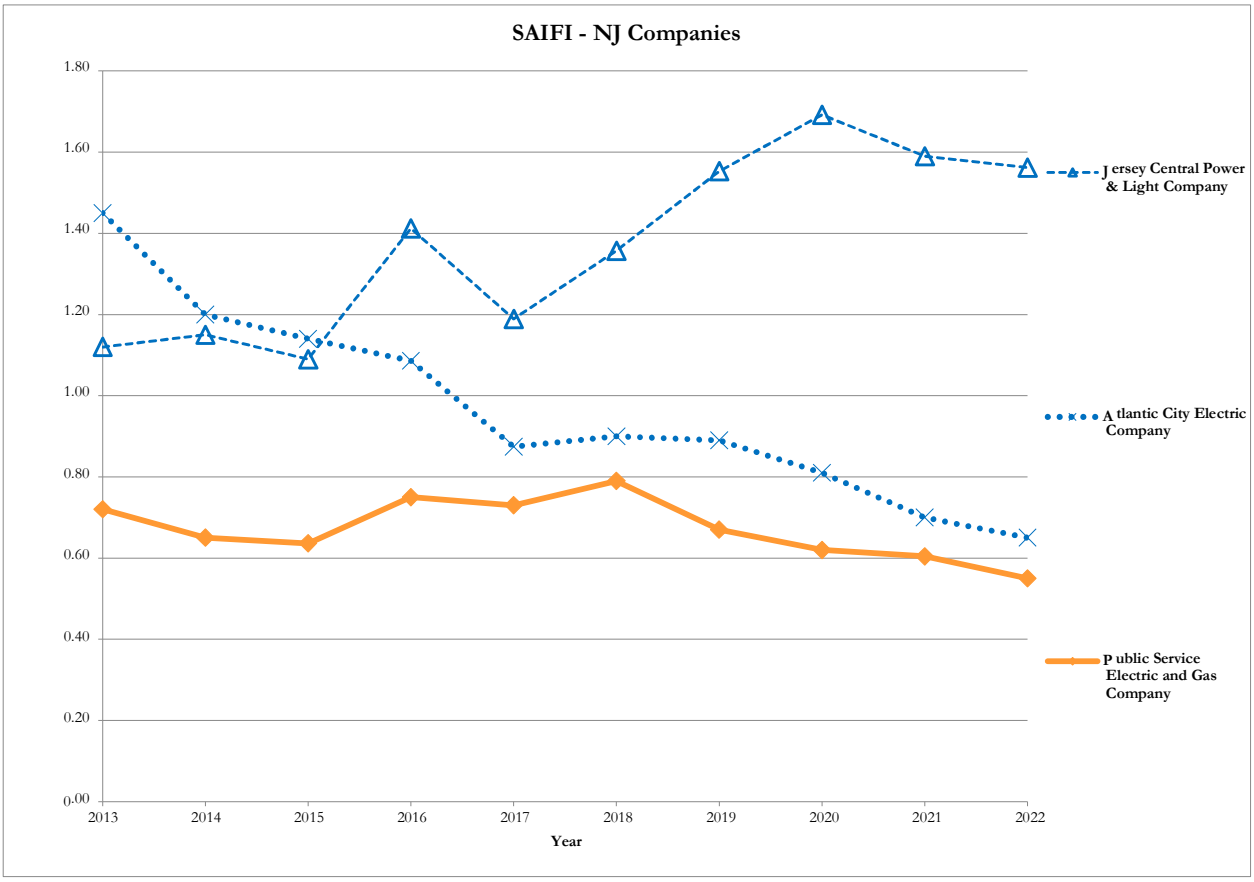


Total Non-Production O&M per Mcf Sold										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company - NJ	1.65	1.30	1.49	1.49	1.51	1.42	1.39	1.39	1.29	1.42
LDC Group Mean (excluding PSEG)	1.74	1.77	1.82	1.98	2.02	1.94	1.92	2.05	1.98	2.02
Regional Group Mean (excluding PSEG)	2.17	2.25	2.29	2.52	2.53	2.40	2.41	2.69	2.58	2.62
New Jersey Group Mean (excluding PSEG)	2.13	2.21	2.30	2.34	2.27	2.17	2.36	2.88	3.04	3.17
ROE Proxy Group Mean (excluding PSEG)	1.59	1.58	1.69	1.80	1.77	1.50	1.60	1.81	1.54	1.47



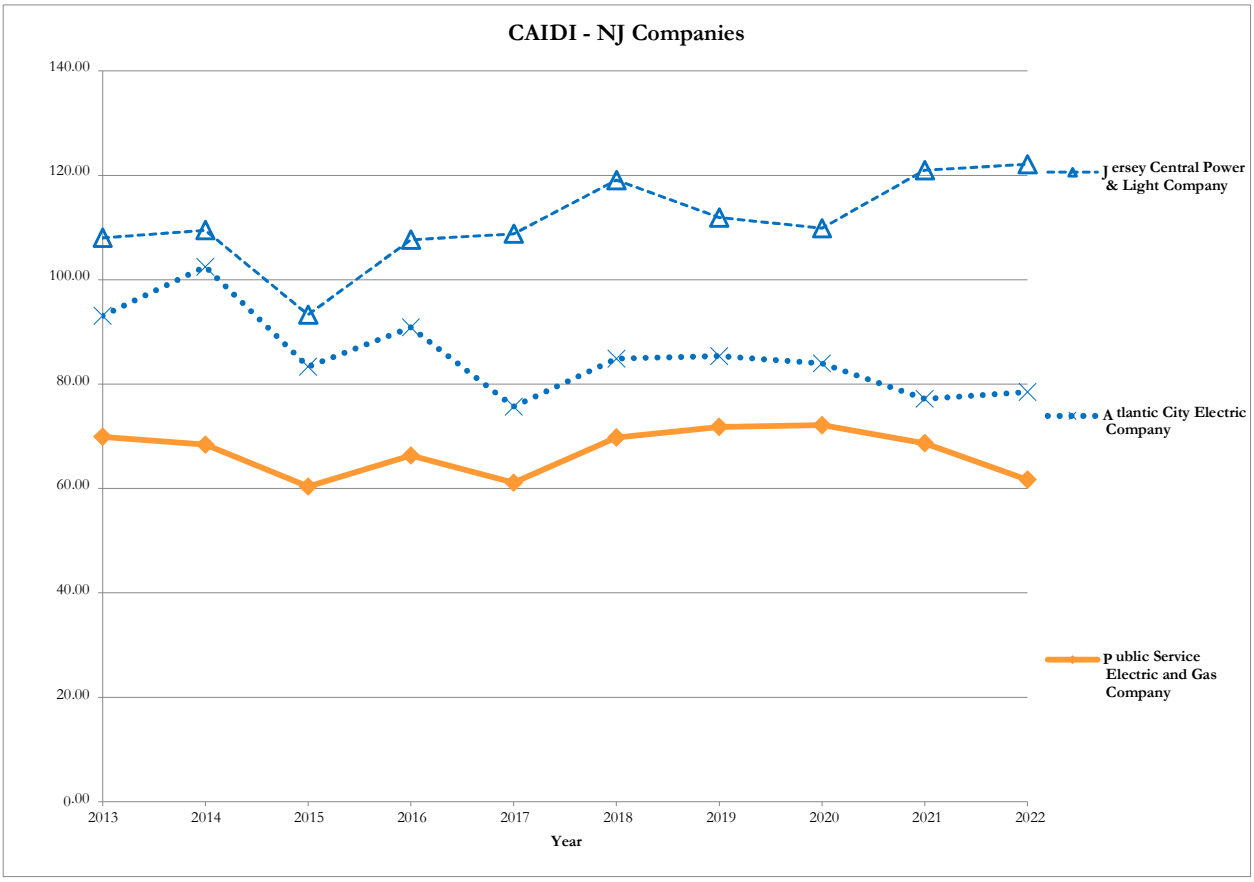
SAIDI - NJ Companies										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	50.27	44.45	38.41	49.74	44.61	55.10	48.11	44.72	41.49	33.94
Atlantic City Electric Company	135.00	123.00	95.00	98.66	66.15	76.40	76.00	68.00	54.00	51.00
Jersey Central Power & Light Company	121.00	125.91	101.70	152.03	129.37	161.59	173.81	185.89	192.36	190.75
New Jersey Group Mean (excluding PSEG)	128.00	124.46	98.35	125.35	97.76	119.00	124.90	126.95	123.18	120.88

Source: EIA Form 861. 2013 PSEG data was provided by the Company.



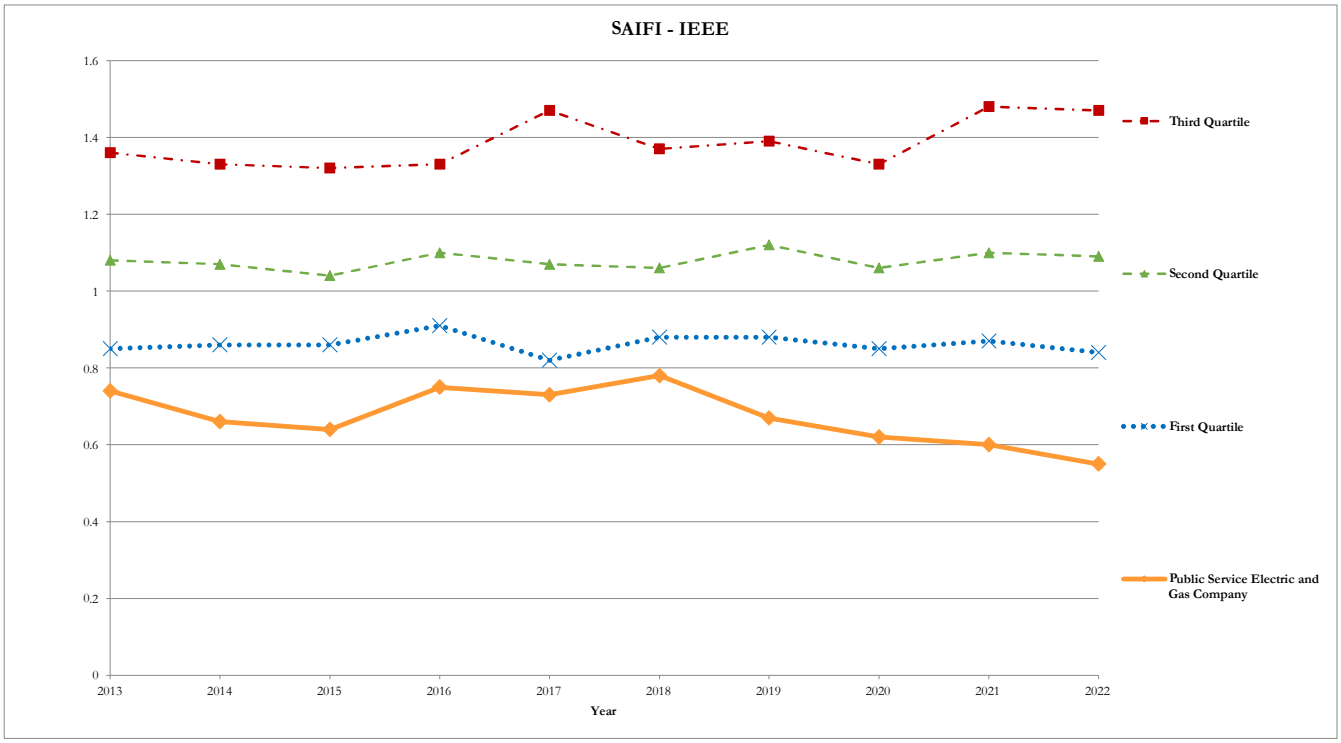
SAIFI - NJ Companies										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	0.72	0.65	0.64	0.75	0.73	0.79	0.67	0.62	0.60	0.55
Atlantic City Electric Company	1.45	1.20	1.14	1.09	0.87	0.90	0.89	0.81	0.70	0.65
Jersey Central Power & Light Company	1.12	1.15	1.09	1.41	1.19	1.36	1.55	1.69	1.59	1.56
New Jersey Group Mean (excluding PSEG)	1.29	1.18	1.12	1.25	1.03	1.13	1.22	1.25	1.15	1.11

Source: EIA Form 861. 2013 PSEG data was provided by the Company.



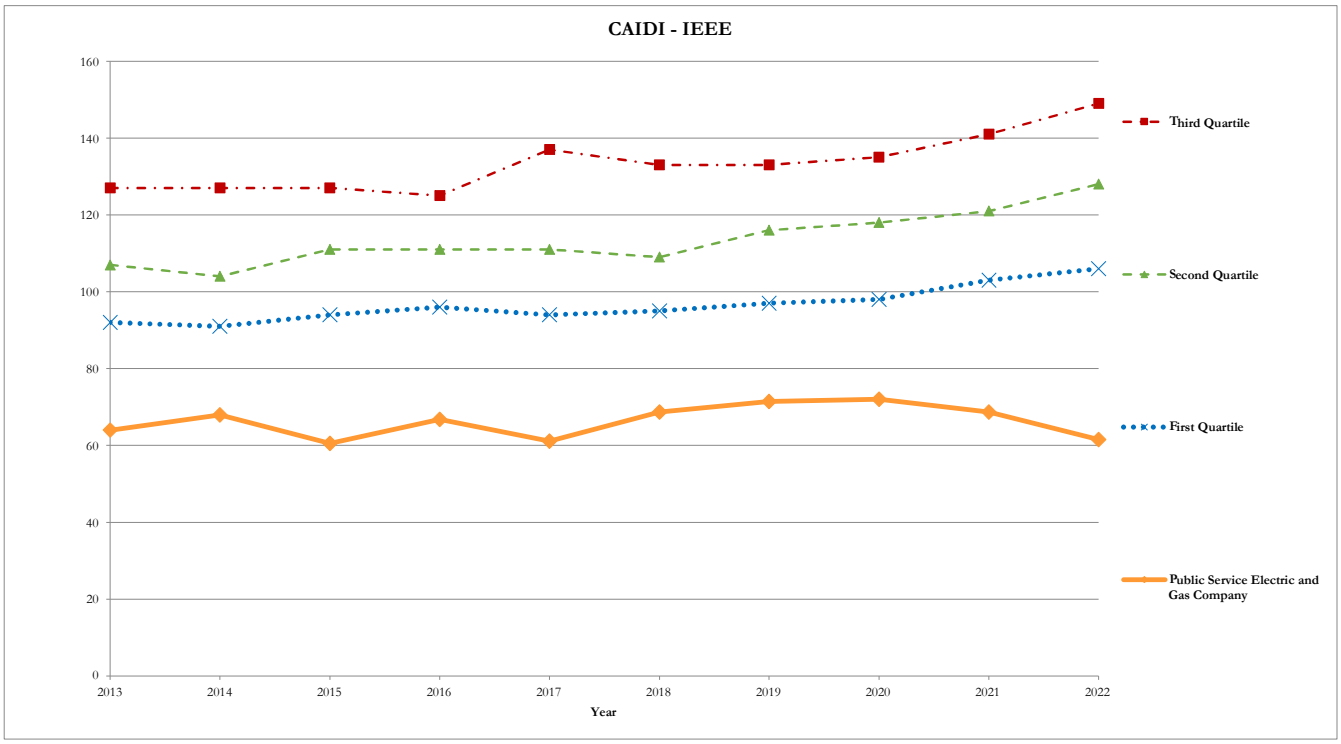
CAIDI - NJ Companies										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	69.89	68.38	60.39	66.32	61.11	69.75	71.81	72.13	68.69	61.71
Atlantic City Electric Company	93.10	102.50	83.33	90.85	75.69	84.89	85.39	83.95	77.14	78.46
Jersey Central Power & Light Company	108.04	109.49	93.30	107.67	108.80	119.08	111.92	109.86	120.98	122.12
New Jersey Group Mean (excluding PSEG)	100.57	105.99	88.32	99.26	92.25	101.98	98.66	96.91	99.06	100.29

Source: EIA Form 861. 2013 PSEG data was provided by the Company.



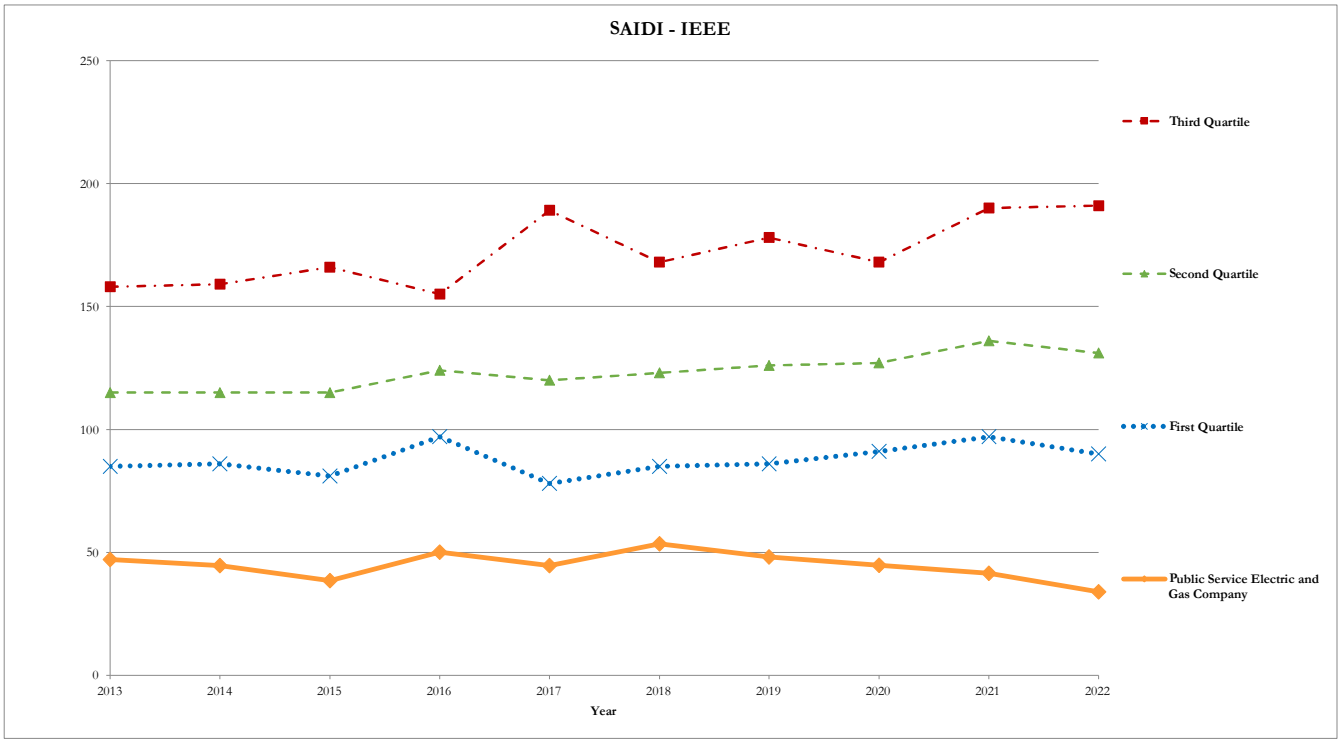
SAIFI - IEEE										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	0.74	0.66	0.64	0.75	0.73	0.78	0.67	0.62	0.60	0.55
Third Quartile	1.36	1.33	1.32	1.33	1.47	1.37	1.39	1.33	1.48	1.47
Second Quartile	1.08	1.07	1.04	1.10	1.07	1.06	1.12	1.06	1.10	1.09
First Quartile	0.85	0.86	0.86	0.91	0.82	0.88	0.88	0.85	0.87	0.84

Source: IEEE



CAIDI - IEEE										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	64	68	61	67	61	69	71	72	69	62
Third Quartile	127	127	127	125	137	133	133	135	141	149
Second Quartile	107	104	111	111	111	109	116	118	121	128
First Quartile	92	91	94	96	94	95	97	98	103	106

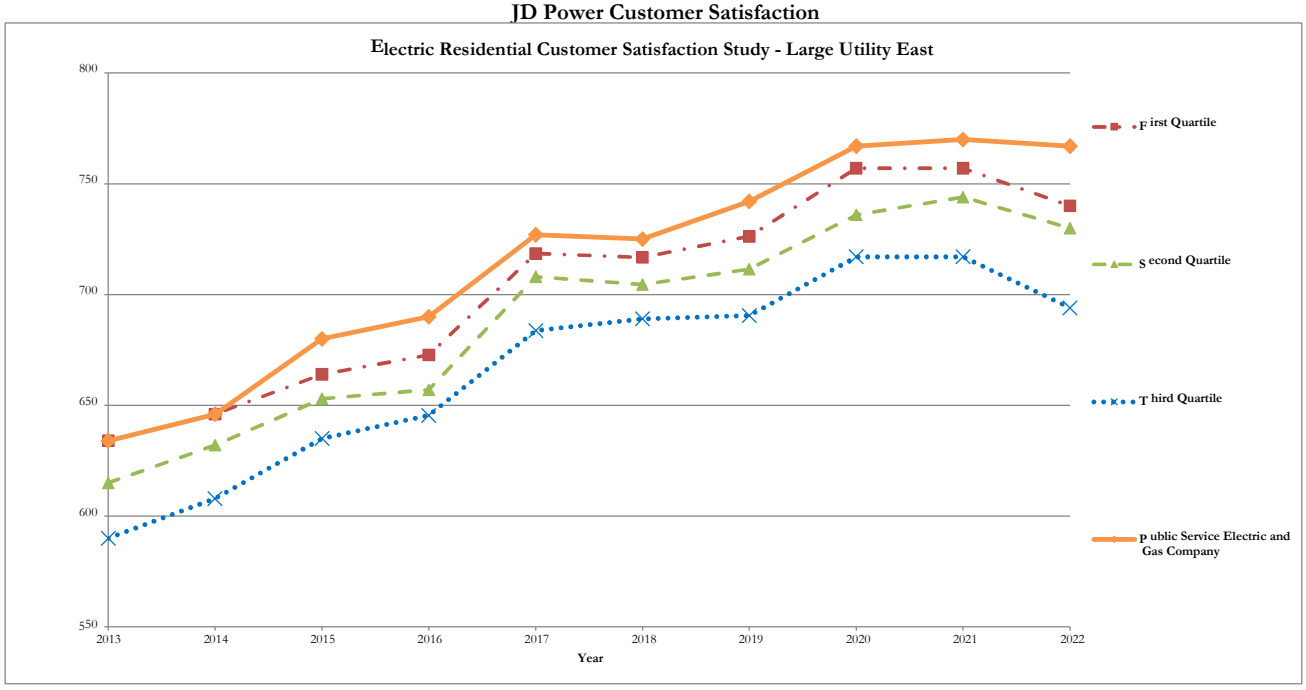
Source: IEEE



SAIDI - IEEE										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	47	45	39	50	45	54	48	45	41	34
Third Quartile	158	159	166	155	189	168	178	168	190	191
Second Quartile	115	115	115	124	120	123	126	127	136	131
First Quartile	85	86	81	97	78	85	86	91	97	90

Source: IEEE

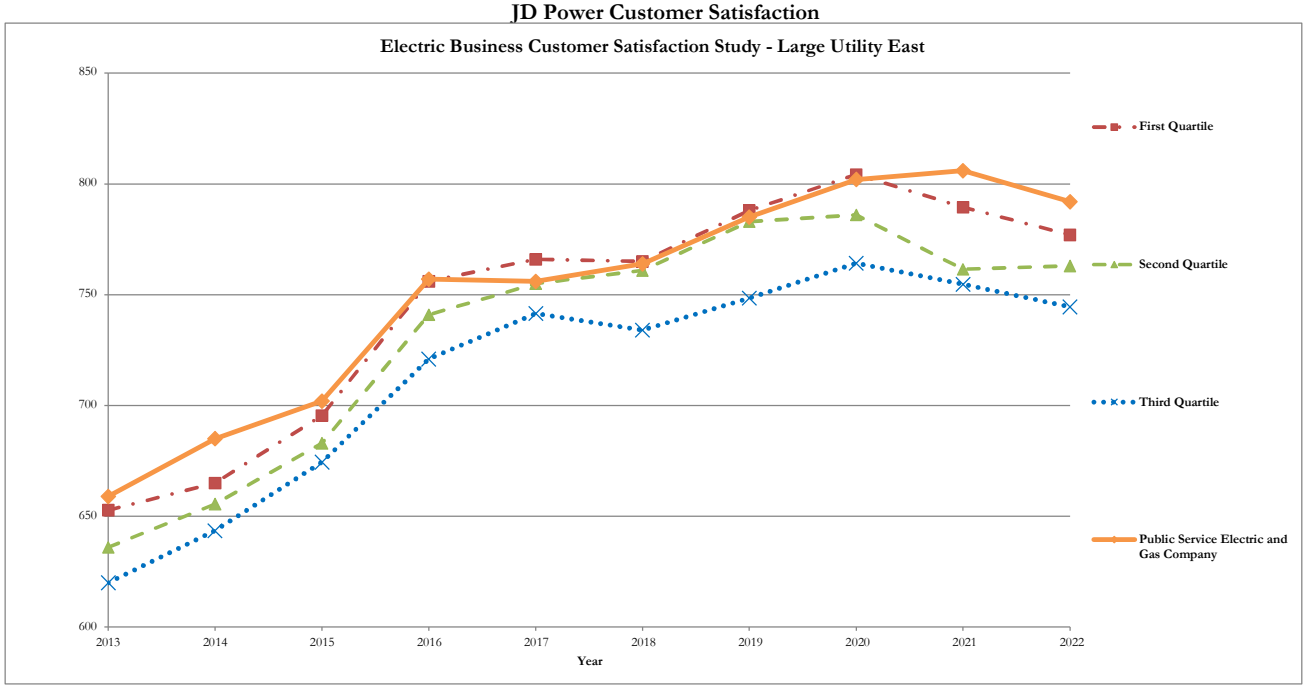
JD Power Customer Satisfaction



Electric Residential Customer Satisfaction Study - Large Utility East										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	634	646	680	690	727	725	742	767	770	767
First Quartile	634	646	664	673	719	717	726	757	757	740
Second Quartile	615	632	653	657	708	705	712	736	744	730
Third Quartile	590	608	635	646	684	689	691	717	717	694

Source: JD Power

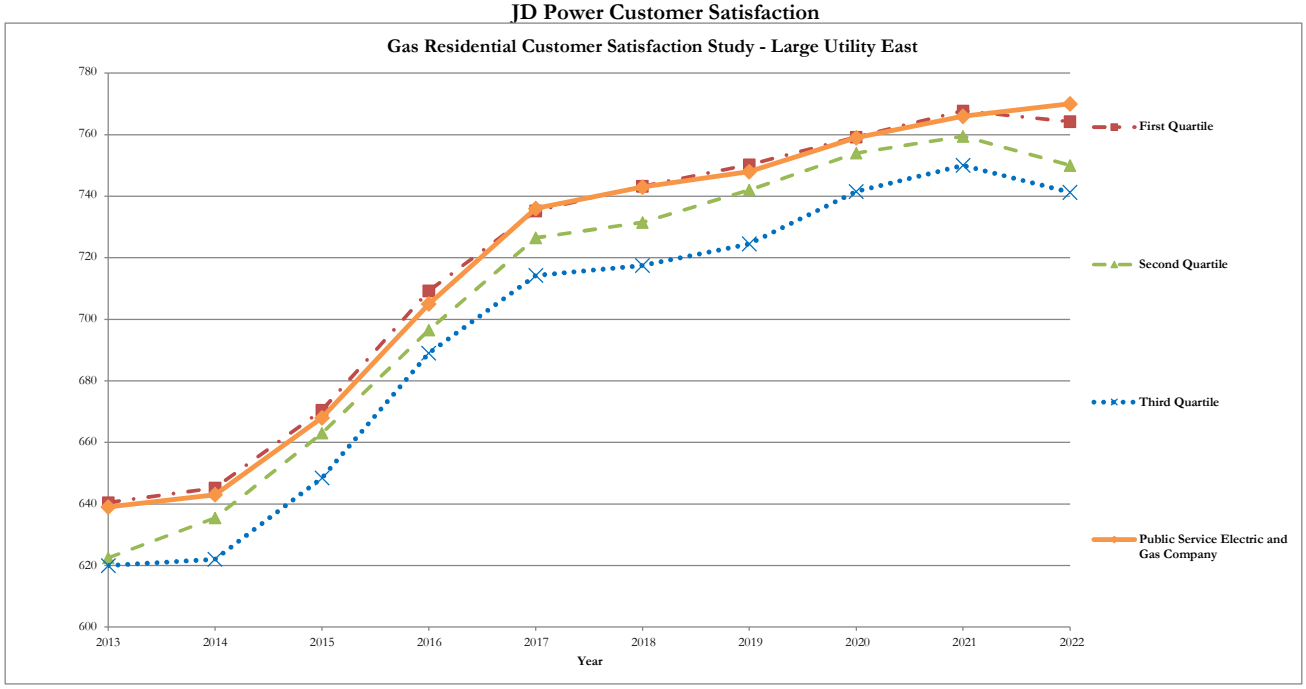
JD Power Customer Satisfaction



Electric Business Customer Satisfaction Study - Large Utility East										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	659	685	702	757	756	764	785	802	806	792
First Quartile	653	665	696	756	766	765	788	804	790	777
Second Quartile	636	656	683	741	755	761	783	786	762	763
Third Quartile	620	644	675	721	742	734	749	764	755	745

Source: JD Power

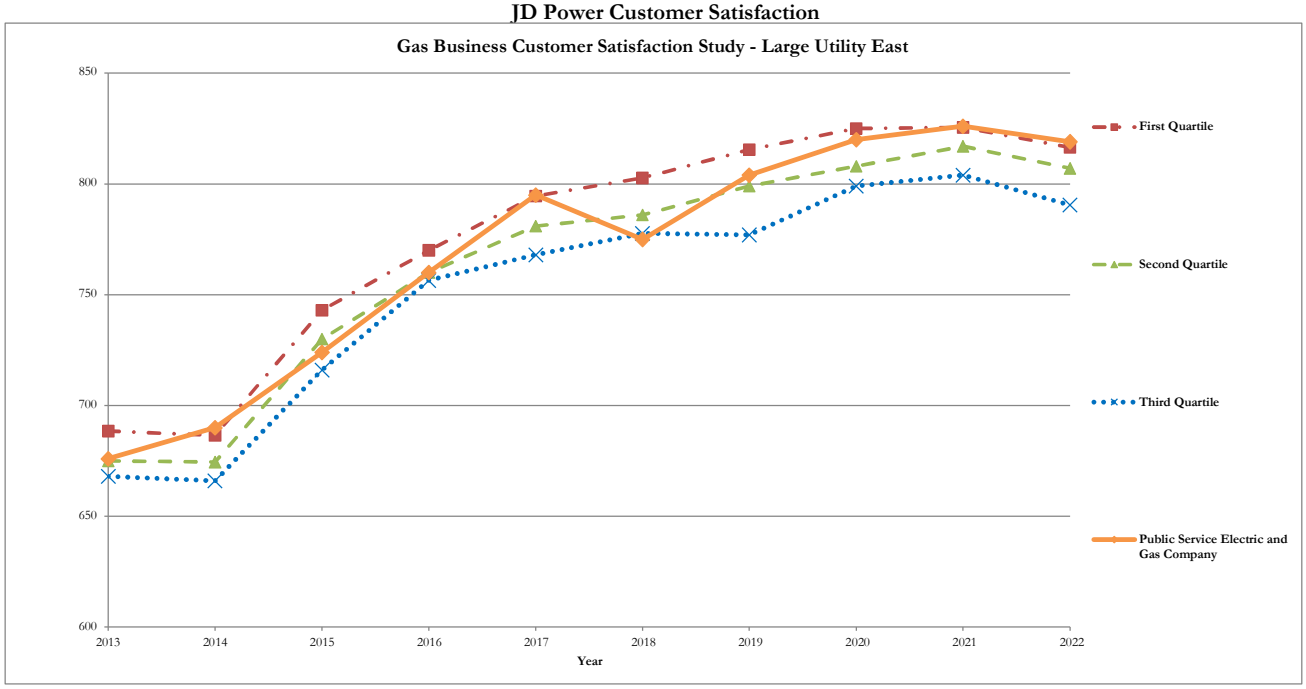
JD Power Customer Satisfaction



Gas Residential Customer Satisfaction Study - Large Utility East										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	639	643	668	705	736	743	748	759	766	770
First Quartile	641	645	671	709	735	743	750	759	768	764
Second Quartile	623	636	663	697	727	732	742	754	760	750
Third Quartile	620	622	649	689	714	718	725	742	750	741

Source: JD Power

JD Power Customer Satisfaction



Gas Business Customer Satisfaction Study - Large Utility East										
Annual Values										
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Public Service Electric and Gas Company	676	690	724	760	795	775	804	820	826	819
First Quartile	689	687	743	770	795	803	816	825	826	817
Second Quartile	675	675	730	760	781	786	799	808	817	807
Third Quartile	668	666	716	757	768	778	777	799	804	791

Source: JD Power

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rate And for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
JOHN J. SPANOS

Submitted on Behalf

of

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

December 29, 2023
P-7

TABLE OF CONTENTS

I. Introduction .....- 1 -
II. Methods Used in Depreciation Study.....- 3 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
JOHN J. SPANOS
PRESIDENT, GANNETT FLEMING VALUATION
AND RATE CONSULANTS, LLC

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. By whom and in what capacity are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) as President.

Q. Please describe your educational background and qualifications.

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College. I have over 37 years of depreciation experience, which includes giving expert testimony in more than 440 cases before 46 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 800 other depreciation or valuation assignments. Please refer to Schedule JJS-2 for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

Q. Have you submitted testimony to any utility commissions on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to many regulatory commissions, the Federal Energy Regulatory Commission (FERC) and Canadian regulatory bodies. Schedule JJS-2 includes a list of cases in which I have submitted testimony.

Q. What is the purpose of your prefiled direct testimony in this proceeding?

A. I was asked to recommend depreciation rates for Public Service Electric and Gas Company's (PSEG or the Company) Electric Distribution and General Plant Accounts and all Gas and Common Plant Accounts. I am sponsoring Schedules JJS-1 stating the results of my depreciation analysis related to Public Service Electric and Gas Company's electric, gas and common plant as of December 31, 2022 (the Depreciation Study or Study). The recommended depreciation rates for PSEG are set forth on pages VI-4 through VI-7 of Schedule JJS-1.

Q. Would you please summarize your testimony?

A. My testimony will explain the methods and procedures of the Depreciation Study and sets forth the annual depreciation rates as of December 31, 2022 for electric, gas and common plant. Schedule JJS-1 sets forth detailed methods, procedures and results of the Depreciation Study as of December 31, 2022. My Depreciation Study will be explained in Part II of my testimony.

Q. Please summarize the principal conclusion of your depreciation study.

A. The principal conclusion of the Electric and Gas Studies is that PSEG's current depreciation rates must be updated as the parameters upon which those rates are based are no longer appropriate. I have proposed updated depreciation accrual rates by plant account in the Depreciation Study. Generally, my recommended rates are based on a combination of my review

of historic data and PSEG's operating maintenance practices, as well as the application of informed engineering judgment. Schedule JJS-3 sets forth a comparison of the proposed rates vs. current rates as of December 31, 2022.

II. METHODS USED IN DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation and valuation?

A. Yes.

Q. Please describe the contents of your report.

A. The Depreciation Study, Schedule JJS-1 is presented in nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curve. Parts III and IV set forth the analysis for determining life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses and the detailed depreciation calculations by account.

Schedule JJS-1, Tables 1 and 2 on pages VI-4 through VI-7 present the estimated survivor curve, net salvage percentage, the original cost as of December 31, 2022, the calculated annual depreciation accrual amount and rate, book depreciation reserve, future accruals and the composite remaining life for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the analyses of historical net salvage data. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2022. The appendix sets forth the depreciation results using the net normalization method for net salvage.

Q. Please identify the depreciation method that you used.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. This is the method which PSEG used in its most recent rate proceedings. This method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner.

Electric General Plant Accounts 391.1, 391.2, 391.31, 392.1, 392.2, 393, 394, 395, 396, 397, and 398, and for Gas General Plant Accounts 391.1, 391.2, 391.3, 391.33, 392.1, 392.2, 393, 394, 395, 396, 397 and 398, I used the straight line remaining life method of amortization, which is consistent with current practices. The account numbers identified throughout my testimony represent those in effect as of December 31, 2022. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Amortization accounting for certain accounts is recommended because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented on pages V-4 and V-5 of the Depreciation Study.

Q. What are your recommended annual depreciation accrual rates for PSEG?

A. My recommended annual depreciation accrual rates as of December 31, 2022 for PSEG are set forth on pages VI-4 through VI-7 of Schedule JJS-1.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group (*i.e.,* each plant account or subaccount identified as having similar characteristics). In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life characteristics for each depreciable group.

A. The service life study consisted of compiling historic data from records related to PSEG's plant; analyzing these data to obtain historic trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric and gas utilities to form judgments of average service life characteristics**.**

Q. What historic data did you analyze for the purpose of estimating service life characteristics?

A. I analyzed the Company's accounting entries that record plant transactions during the 48-year period 1975 through 2022 for all electric and gas assets. The transactions included additions, retirements, transfers and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of December 31, 2022.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method for all accounts. This is the most appropriate method when aged retirement data are available, because it determines the average rates of retirement actually experienced by the Company during the period covered by the study.

Q. Would you explain how you used the retirement rate method to analyze PSEG's service life data?

A. I applied the retirement rate method to each different group of property in the study. For each property group, I used the retirement rate method to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies.

The Iowa curves were developed at the Iowa State University College of Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. As I will explain, the use of truncated curves is appropriate to reflect retirements of plant components that may not be fully depreciated at the time a plant is retired.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 60-R1 indicates an average service life of sixty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. What approach did you use to estimate the lives of significant structures such as office buildings?

A. I used the life span technique to estimate the lives of significant structures for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows and roofs, which occur during the life of the facility. The probable retirement date

provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has Gannett Fleming used this approach in other proceedings?

A. Yes. We have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada. This is consistent with the development of current rates.

Q. What are the bases for the probable retirement years that you have estimated for the Office Building?

A. The probable retirement year for the Office Building is based on my professional judgment and incorporates consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other utilities for similar facilities. The life span results in a probable retirement year that is many years in the future. As a result, the retirement of this facility is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. Have you physically observed PSEG's assets as part of your depreciation study?

A. Yes. I made field reviews of PSEG's property in September 2023 to update my analyses on a representative portion of plant. I have conducted field visits as part of prior studies in

October and November 2016. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. For example, I had detailed discussions with Company personnel regarding the different forces of retirement for some of their regions. This knowledge as well as information from other discussions with management was incorporated into my statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar plants and meet with operations personnel at other companies. The knowledge accumulated from those visits and meetings provide me useful information that I can draw on to confirm or challenge my numerical analyses concerning plant condition and remaining life estimates.

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, *e.g.,* one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of $5,000 distribution overhead conductors will include not only the $5,000 of original cost, but also, on average, $1,300 to remove at the end of its life and $50 in salvage value. In this example, the net salvage component is negative $1,250 ($50 - $1,300), and the net salvage percent is negative 25% (($50 - $1,300)/$5,000).

Q. Have you included a net salvage percentage as part of the depreciation accrual rate?

A. Yes, in order to be consistent with the most common practice for determining accrual accounting. However, the recent practices by the New Jersey Board of Public Utilities, the net salvage percentage accrual has been replaced by a net salvage normalization amount. The net salvage normalization method is a backward looking average of experienced net salvage costs. I do not believe it is an appropriate and reasonable method for recovery of the net salvage costs. As discussed in greater detail below, the normalization approach pushes the cost of removal away from customers who benefit from the assets providing service and onto future customers. This is an example of intergenerational inequity. The net normalization method is set forth in the Appendix of the Depreciation Study.

Q. Please describe how recent practice in New Jersey has estimated net salvage normalization amounts.

A. The estimate of the net salvage normalization amounts for each account has been based on historical data for the most recent 5-year period which in this case would be 2018-2022. In the historical analyses cost of removal and gross salvage amounts were recorded by account within the 5-year period, 2018-2022. Years prior to 2018 were reviewed to understand the trend of cost of removal and gross salvage which show cost of removal has been increasing at a high rate. Then in this practice the five-year average of these experienced costs is calculated and incorporated as the annual cost of removal expense reflected in the depreciation rate.

Q. Please describe the process that you used in the Depreciation Study to calculate composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The annual depreciation accrual rates were developed as of December 31, 2022.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and this rate is applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the sum of the future book accruals is divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. You stated earlier that for general plant accounts you continued the use of amortization accounting to calculate proposed deprecation rates. Could you please describe amortization accounting?

A. Yes. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, amortization accounting is more appropriate than depreciation accounting for accounts with a large number of units, but small asset values. This is true because in order to properly reflect plant in service, depreciation accounting requires periodic inventories, which is a difficult and burdensome task for these assets (*i.e.*, large number of units, but small values). Consequently, a more accurate method is to record retirements when a vintage is fully amortized rather than as the units are removed from service. As a result, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 7-year amortization period will be fully recovered after 7 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 7 years remain on the books until the amortization period for that vintage has expired.

Q. Can you explain why you recommend amortization accounting?

A. Amortization accounting has been implemented by almost all utility companies across the United States and Canada over the past 25-30 years. I have presented this methodology in the depreciation study in order to smooth the annual depreciation accrual rate over time for the specific asset classes described in general plant as well as to improve record keeping practices for a large number of assets that have a small utility plant in service value.

Q. For which plant accounts is amortization accounting being implemented?

A. Amortization accounting is only appropriate for certain General Plant accounts. These are accounts 390.1, 391.1, 391.2, 391.31, 392.1, 392.2, 393, 394, 395, 396, 397, and 398 for electric plant and 391.1, 391.2, 391.3, 391.33, 392.1, 392.2, 393, 394, 395, 396, 397 and 398 for gas plant. They represent slightly less than three percent of electric depreciable plant and slightly more than one percent of gas depreciable plant.

Q. Please use an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in your depreciation study.

A. I will use Electric Account 367, Underground Transformers, as an example because it is one of the largest depreciable groups and represents approximately 14% of depreciable plant for PSEG's electric distribution plant.

I used the retirement rate method to analyze the survivor characteristics of this property group. I compiled aged plant accounting data from 1976 through 2022 and analyzed the data for periods that best represent the overall service life of the property. I present the life tables for the 1976-2022 and 1990-2022 experience bands on pages VII-36 through VII-41 of Schedule JJS-1. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-36 shows $1,693,667 retired during age interval 0.5-1.5 with $1,497,824,649 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0011 ($1,693.667/$1,497,824,649) and the surviving ratio is 0.9989 (1-.0011). The percent surviving at age 0.5 of .9989 percent is multiplied by the survivor ratio of 99.92 to derive the percent surviving at age 1.5 of 99.80 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1976-2022. The resultant life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 58-R2 on page VII-35.

The net salvage percent is presented on pages VIII-18 through VIII-20. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1977 through 2022. The 46-year period experienced negative $70,137,501 ($38,628,699-$108,766,199) in net salvage for $157,148,249 plant retired. The result is negative net salvage of 45% ($70,137,501/$157,148,249). Based on the statistics for this account as well as the three-year rolling averages, most recent five-year average and the estimates of others in the industry, the recommended net salvage for underground conductor is negative 20%.

I provide my calculation of the annual depreciation related to original cost of Account 367, Underground Conductors and Devices, as of December 31, 2022, on pages IX-19 through IX-21 Schedule JJS-1. The calculation is based on the 58-R2 survivor curve, negative 20 percent net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to Table 1 on page VI-4.

Q. Please explain the method for the recovery of net salvage used in the Appendix of Schedule JJS-1.

A. The Appendix sets forth accruing for net salvage based on the net salvage costs over the most recent five years. Basically, an expense approach where the level of net salvage over the last five years will be the component of net salvage to be added to the life depreciation rate.

Q. What has been the practices in New Jersey in recent years?

A. In recent years, the practice in New Jersey sets the depreciation accruals for net salvage similar to, if not the same as, the average of the most recent 5-year expenditures on net salvage. If this is taken to its logical extension, the annual net salvage accruals in a given year should be

the same as (or at least approximate) the costs incurred during that year. As a result, the current practices, in effect, recover net salvage as an operating expense instead of recovering the service value of assets over the assets' service lives. This occurs because this approach does not provide for recovery of the full net salvage that will be incurred for plant currently in service. The result is lower revenue requirements today, but with the deferral of recovery to future customers with a net result of recovery of less than the full amount of removal costs.

Q. Can you explain the differences between the traditional method and the New Jersey approach?

A. Yes. When using the traditional method, net salvage is estimated as a percentage of the original cost of plant. The statistical analysis used in estimating net salvage is based on comparing historical, not only recent, net salvage expenditures to historical retirements. This methodology, which to my knowledge is supported by all authoritative depreciation texts, provides a reasonable basis for net salvage estimation because the amount of net salvage expended in a given year is a function of the number of assets retired in that year. That is, if the Company were to retire 1,000 poles in one year, it should be expected to have a higher total net salvage cost than if it were to only retire 100 poles. Therefore, it is reasonable to expect net salvage to increase in proportion to the amount of retirements that occur. The traditional method recognizes this relationship. This relationship is important because most companies should be expected to have more retirements in the future than they have had historically.

Q. Does the current New Jersey method recognize this important relationship?

A. No, it does not. This method fails to recognize that net salvage is a function of the number of assets retired in a given year. By focusing on only the recent net salvage expenditures, the current New Jersey practice is effectively assuming that the Company will experience the same net salvage costs independent of whether it retires 100 poles or 1,000 poles. This method also

fails to recognize that in order to accrue for the net salvage costs for assets currently in service, future net salvage costs must be recognized in depreciation expense. Future net salvage costs (i.e., primarily removal costs) are likely higher than current removal costs, in large part because future retirements will be higher than current retirements. The New Jersey method does not recognize these concepts, and instead is designed to only recover the costs recently spent on assets that have already been retired.

Q. Can you provide a simple example that demonstrates the New Jersey method fails to appropriately allocate net salvage costs over the service lives of property?

A. Yes. Consider the following hypothetical scenario, which I will analyze over a 40-year period:

- A company installs a single asset at a cost of $1,000 in the beginning of year 1.
- The asset has a life of 10 years, and at the end of the asset's life it will be replaced by an identical asset with the same service life and same cost.
- Upon replacement, the cost to remove the retired asset will be $200.
- A depreciation study is conducted periodically; (assume every five years) and new depreciation rates are calculated at the time of each study.

Using these parameters, we can analyze the difference between the traditional method and the New Jersey method.

Q. What is the depreciation rate that would be calculated using the traditional method?

A. Under the traditional method, the net salvage estimate is negative 20% ($200 / $1,000) and the service life estimate is 10 years. The depreciation rate is therefore (1 – (-20%))/10 = 12%. Using the traditional method, the depreciation rate will be the same 12% in each year.

Q. How does this compare to the New Jersey method?

A. Again, the New Jersey method is based on the concept that the annual accruals for net salvage should be the same as recent net salvage expenditures. For the purposes of this example, when using this approach the net salvage estimate is calculated to produce net salvage accruals that equal the most recent five-year average of net salvage expenditures. This will produce a different depreciation rate depending on the recent experience. In the first depreciation study in year 1, the net salvage estimate will be 0%, since the most recent five-year average of net salvage is zero. The same estimate will be made in the second depreciation study in year six. However, in the depreciation study performed in year 11 - after the retirement of the initial asset - the net salvage jumps significantly to negative 40%, resulting in a depreciation rate of 14%. It then falls back to 0% in year 16 before returning to negative 40 percent in year 21. Thus, the depreciation rate fluctuates from 10% to 14% over the lives of the assets. A comparison of the annual depreciation rates and accruals based on the traditional method and the New Jersey method is shown in Table 1 below.

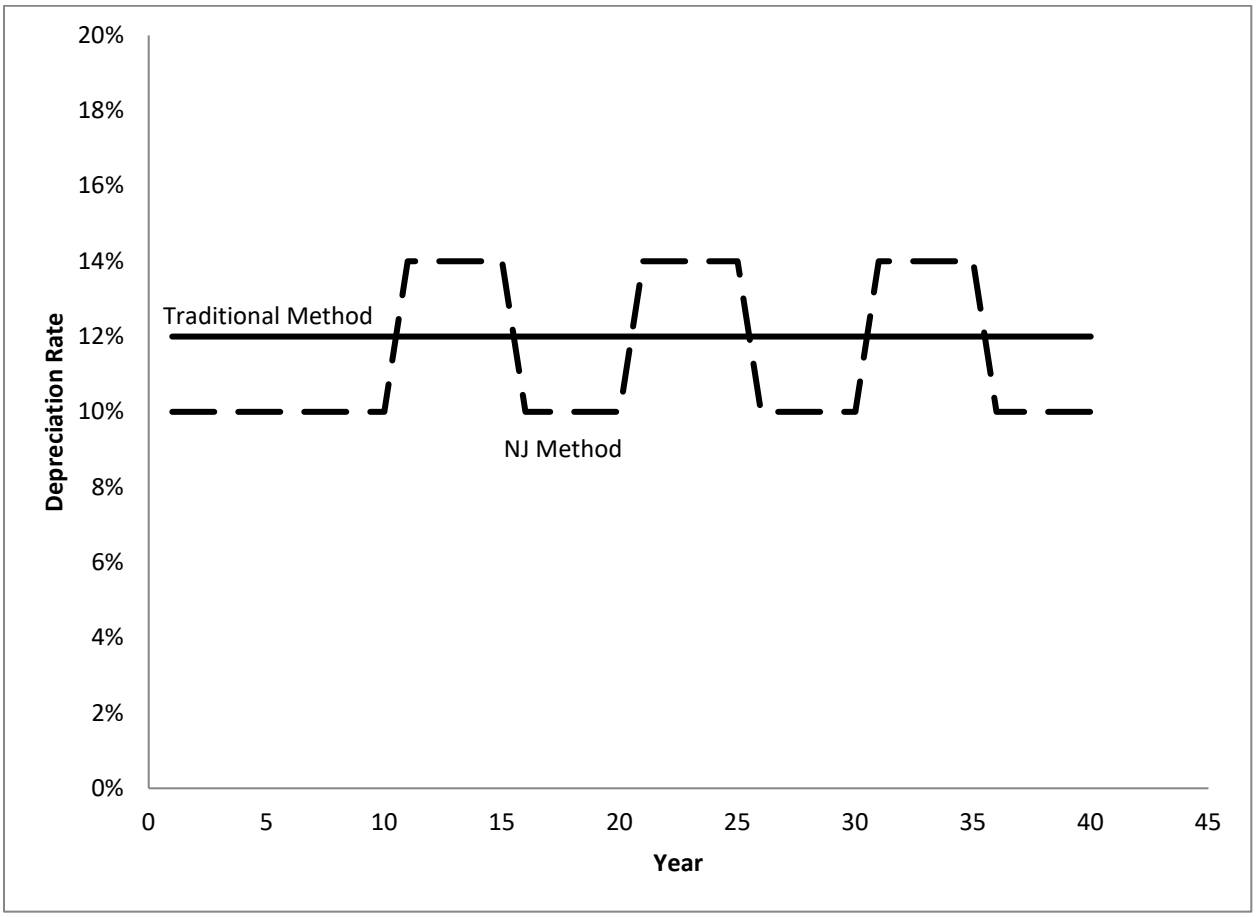
Table 1: Comparison of Annual Depreciation Accruals and Rates

	Traditional Method		NJ Method	
Year	Accrual	Rate	Accrual	Rate
1-5	120	12%	100	10%
6-10	120	12%	100	10%
11-15	120	12%	140	14%
16-20	120	12%	100	10%
21-25	120	12%	140	14%
26-30	120	12%	100	10%
31-35	120	12%	140	14%
36-40	120	12%	100	10%

A comparison of the two methods over time is also shown graphically in Figure 1 below. The figure shows the depreciation rates over the full 40-year period based on each method. The

solid line in the figure presents the depreciation rate in each year using the traditional method. The dashed line represents the depreciation rate in each year using the New Jersey method.

Figure 1: Comparison of Traditional and NJ Methods



As can be seen in both Table 1 and Figure 1, the traditional method results in a consistent recovery pattern over the lives of the assets, and costs are allocated in a systematic and rational manner. By contrast, the depreciation rates using the New Jersey method vary considerably from year to year and from study to study.

Q. Is there a requirement that costs be depreciated in a systematic and rational manner?

A. Yes. The Uniform System of Accounts requires that costs be depreciated in a systematic and rational manner.

Q. What causes the volatility in depreciation rates that occurs when using the New Jersey method, as demonstrated in Figure 1?

A. The volatility is the result of the fact that the New Jersey method is not a forward looking method that estimates the net salvage that will occur in the future for the assets currently in service. Instead, it is backward looking, and only recovers the level of net salvage that has occurred in the recent past. The method therefore has the potential to create wide swings in depreciation rates.

Q. Have you conducted a net salvage accrual analysis to measure how much of an impact in cost of removal recovery results from use of the traditional method as opposed to the net salvage normalization method based on future expected removal costs?

A. Yes. Schedule JJS-3 sets forth the annual depreciation accrual rates by account for electric and gas plant if the industry standard method for calculating the net salvage accrual component embedded in the rates was utilized. The table shows that using the traditional method, the annual total depreciation expense for electric and gas would be $597.5 million (Column 6) versus $516.3 million. The $597.5 million annual expense utilizes net salvage estimates for many accounts which are based on industry ranges, as well as Company statistics. Utilizing the net normalization method is a $81.2 million deficiency in annual depreciation expense that will need to be recovered from future customers in future rate cases.

Q. Does this conclude your testimony?

A. Yes, it does.

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC DISTRIBUTION, GAS AND COMMON PLANT AS OF DECEMBER 31, 2022

Prepared by

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Newark, New Jersey

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC DISTRIBUTION, GAS AND
COMMON PLANT AS OF DECEMBER 31, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Camp Hill, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
207 Senate Avenue
Camp Hill, PA 17011
P 717.763.7211 | **F** 717.763.8150

gannettfleming.com

December 7, 2023

Public Service Electric and Gas Company
80 Park Plaza
Newark NJ 07102

Attention Scott Jennings
Senior Vice President, Finance, Planning and Strategy

Ladies & Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric distribution, gas and common plant of Public Service Electric and Gas Company as of December 31, 2022. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual and accrued depreciation, the statistical support for the service life and net salvage estimates, and the detailed tabulations of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

JOHN J. SPANOS
President

MELISSA M. HOWARD
Senior Analyst

JJS:mle

074479.000

TABLE OF CONTENTS

EXECUTIVE SUMMARY iii

PART I. INTRODUCTION I-1
Scope I-2
Plan of Report I-2
Basis of the Study I-3
Depreciation I-3
Service Life and Net Salvage Estimates I-4

PART II. ESTIMATION OF SURVIVOR CURVES II-1
Survivor Curves II-2
Iowa Type Curves II-3
Retirement Rate Method of Analysis II-9
Schedules of Annual Transactions in Plant Records II-10
Schedule of Plant Exposed to Retirement II-13
Original Life Table II-15
Smoothing the Original Survivor Curve II-17

PART III. SERVICE LIFE CONSIDERATIONS III-1
Field Trips III-2
Service Life Analysis III-2

PART IV. NET SALVAGE CONSIDERATIONS IV-1
Net Salvage Analysis IV-2
Net Salvage Considerations IV-2

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION V-1
Group Depreciation Procedures V-2
Single Unit of Property V-2
Remaining Life Annual Accruals V-3
Average Service Life Procedure V-3
Calculation of Annual and Accrued Amortization V-4

PART VI. RESULTS OF STUDY VI-1
Qualification of Results VI-2
Description of Statistical Support VI-2
Description of Depreciation Tabulations VI-3

TABLE OF CONTENTS, cont

Table 1. Summary of Estimated Survivor Curve, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Accruals Related to Electric and Common Plant as of December 31, 2022 ..... VI-4
Table 2. Summary of Estimated Survivor Curve, Net Salvage Percent, Original Cost, Book Depreciation Reserve and Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2022 ..... VI-6

PART VII. SERVICE LIFE STATISTICS VII-1
Electric VII-2
Gas VII-70
Electric, Gas and Common VII-157

PART VIII. NET SALVAGE STATISTICS VIII-1
Electric VIII-2
Gas VIII-33

PART IX. DETAILED DEPRECIATION CALCULATIONS IX-1
Electric IX-2
Common IX-33
Gas IX-36

APPENDIX A-1
Electric A-7
Common A-38
Gas A-41

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Public Service Electric and Gas Company's ("PSEG" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric distribution, gas and common plant as of December 31, 2022. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric distribution, gas and common plant in service as of December 31, 2022 as summarized in Column 9 of Table 1 and Column 8 of Table 2 of the Study.

The study results set forth an annual depreciation expense of $597.6 million when applied to depreciable plant balances as of December 31, 2022. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST	PROPOSED RATE	PROPOSED EXPENSE
Electric Plant			
Distribution Plant	$10,638,819,527.08	2.71	$287,908,662
General Plant	34,060,708.63	1.80	612,821
General Plant-Amortized	323,859,151.30	9.00	29,154,679
Common Plant	71,440,287.98	2.55	1,824,328
Total Electric and Common Plant	**$11,068,179,674.99**	**2.89**	**$319,500,490**
Gas Plant			
Production Plant	$ 50,884,995.97	0.00	$ 1,448
Other Storage Plant	19,551,736.69	1.16	226,449
Transmission Plant	98,123,267.16	1.82	1,788,861
Distribution Plant	10,350,466,845.66	2.49	257,571,663
General Plant	23,262,931.72	1.82	424,132
General Plant-Amortized	176,368,559.37	10.23	18,037,685
Total Gas Plant	**$10,718,658,336.57**	**2.59**	**$278,050,238**
Total Depreciable Electric, Common and Gas Plant	**$21,786,838,011.56**		**$597,550,728**

PART I. INTRODUCTION

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Public Service Electric and Gas Company ("PSEG" or "Company"), as applied to specific electric, gas and common plant in service as of December 31, 2022. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric, gas and common plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2022; the net salvage analyses of historical plant retirement data recorded through 2022; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric and gas industry, including knowledge of service lives and net salvage estimates used for other electric and gas companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the

salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric or gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric and gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric and gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the

probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and net salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and gross salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

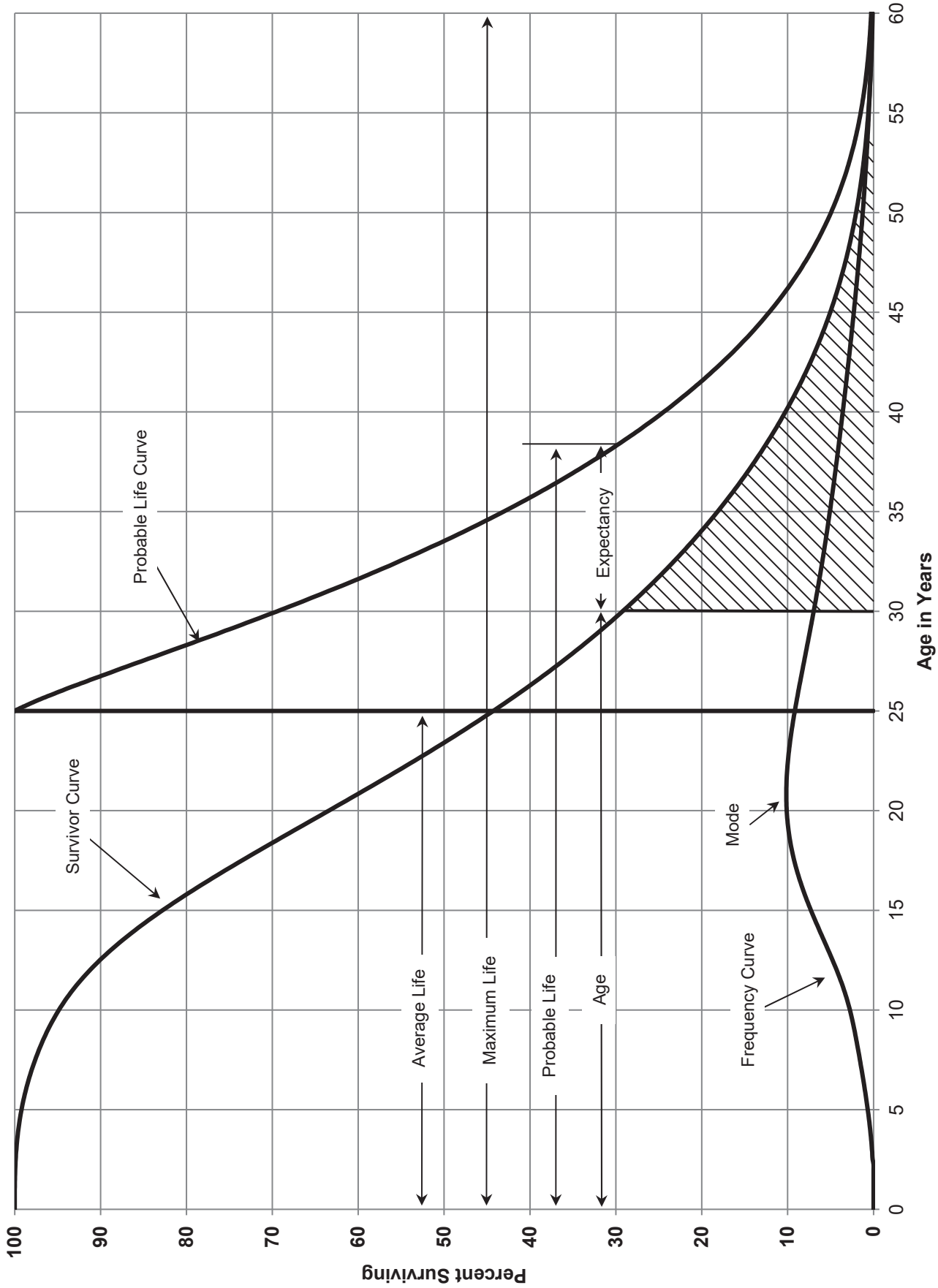


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

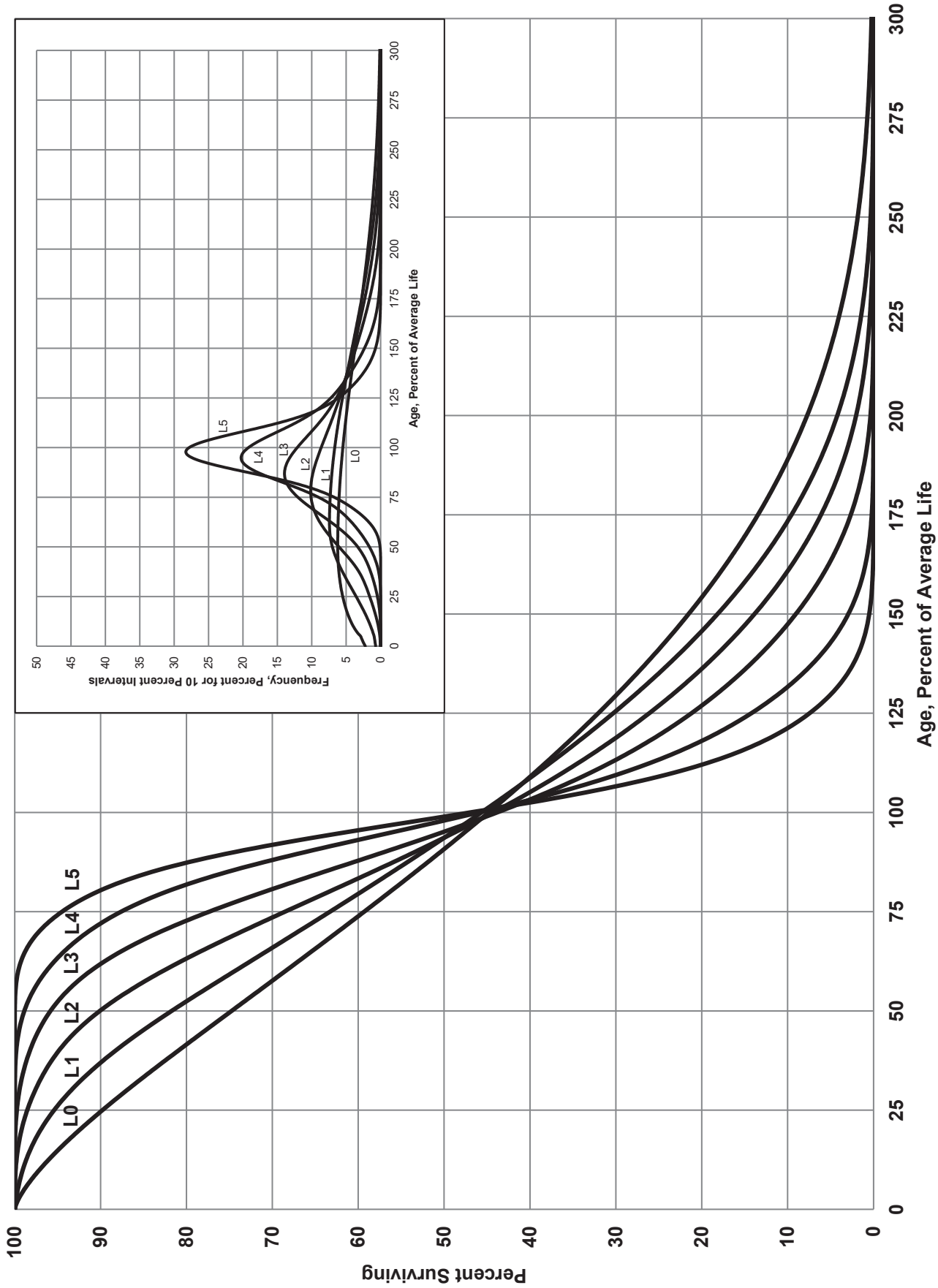


FIGURE 2.. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

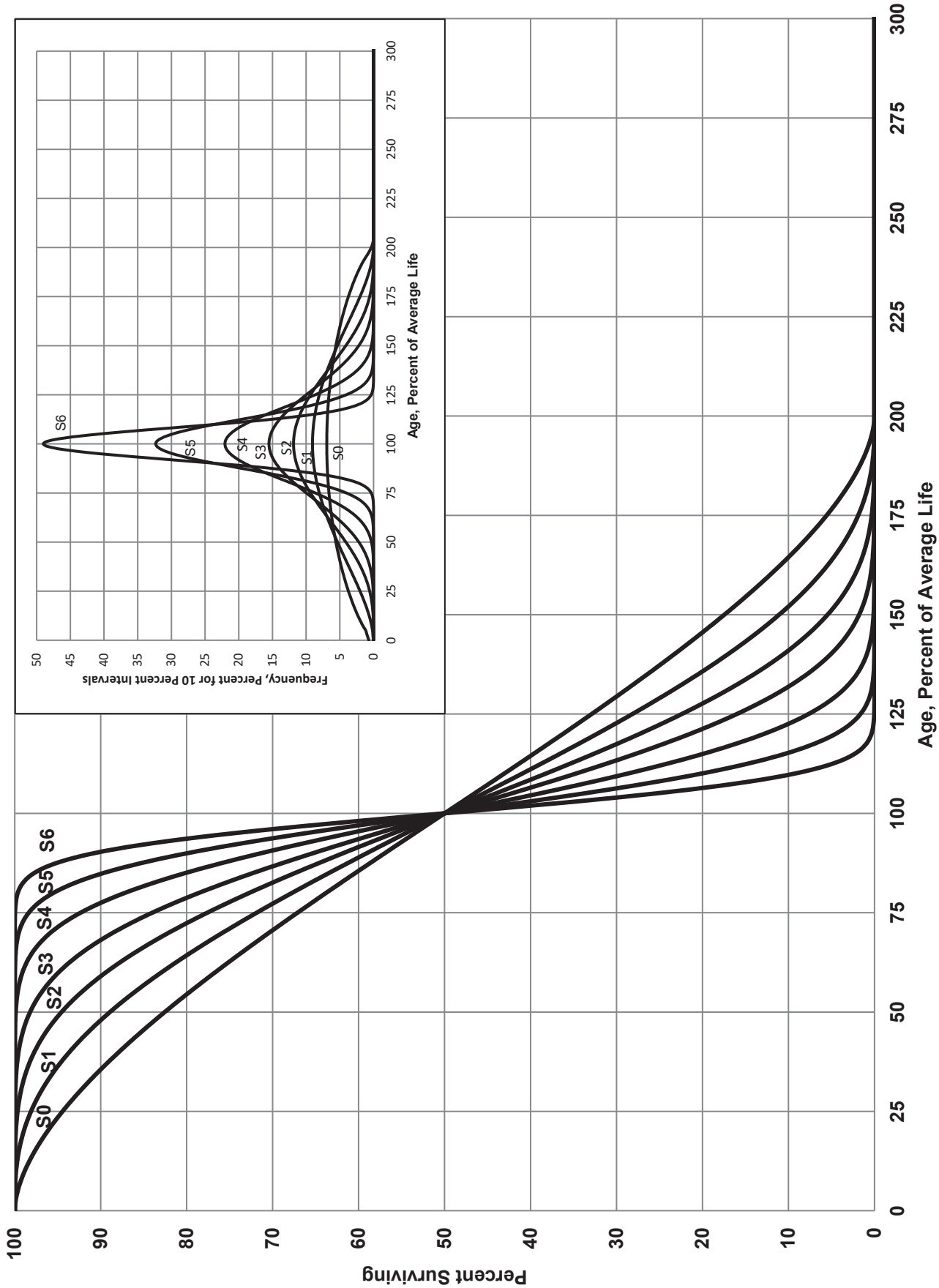


FIGURE 3.. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

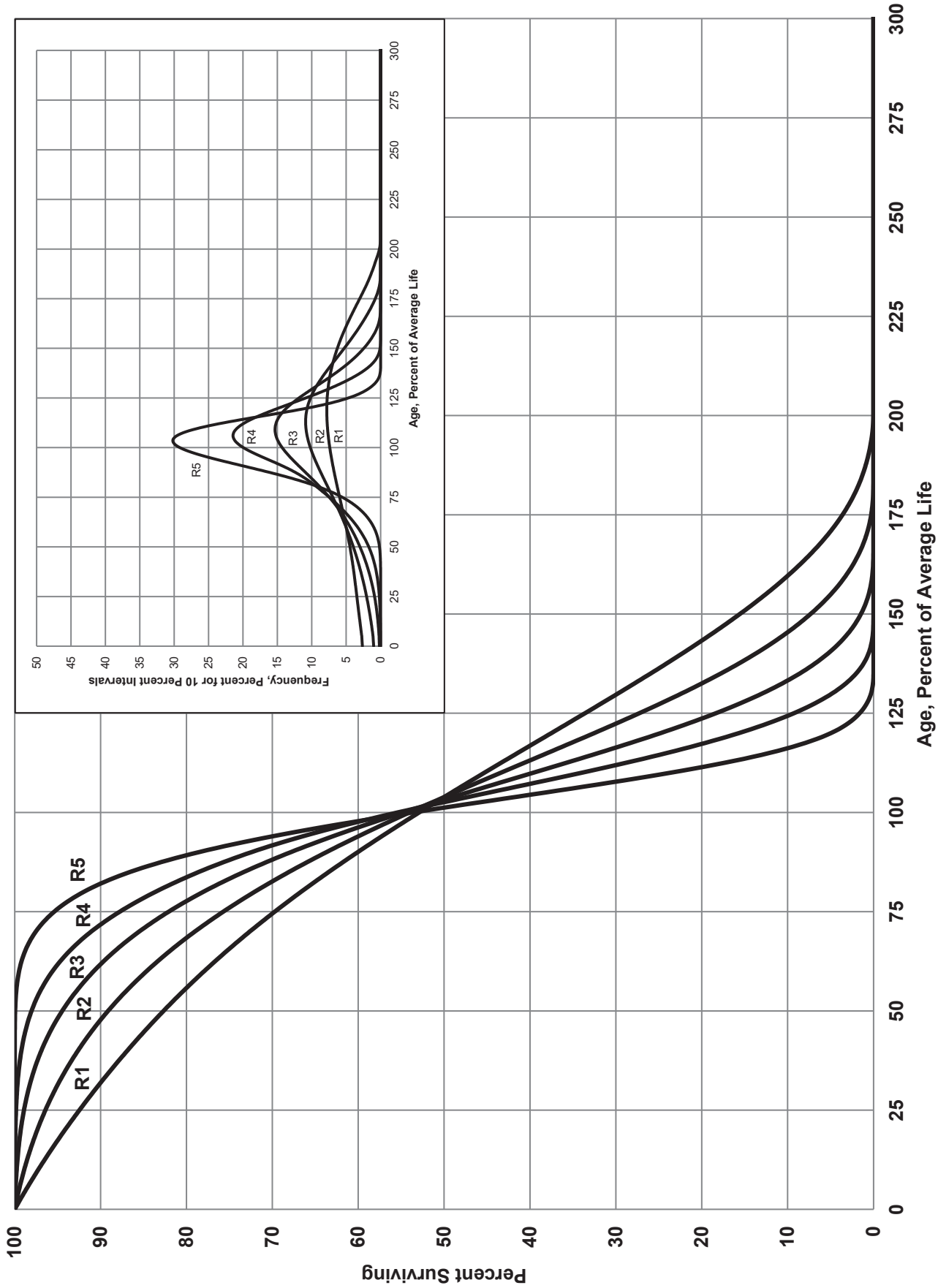


FIGURE 4.. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

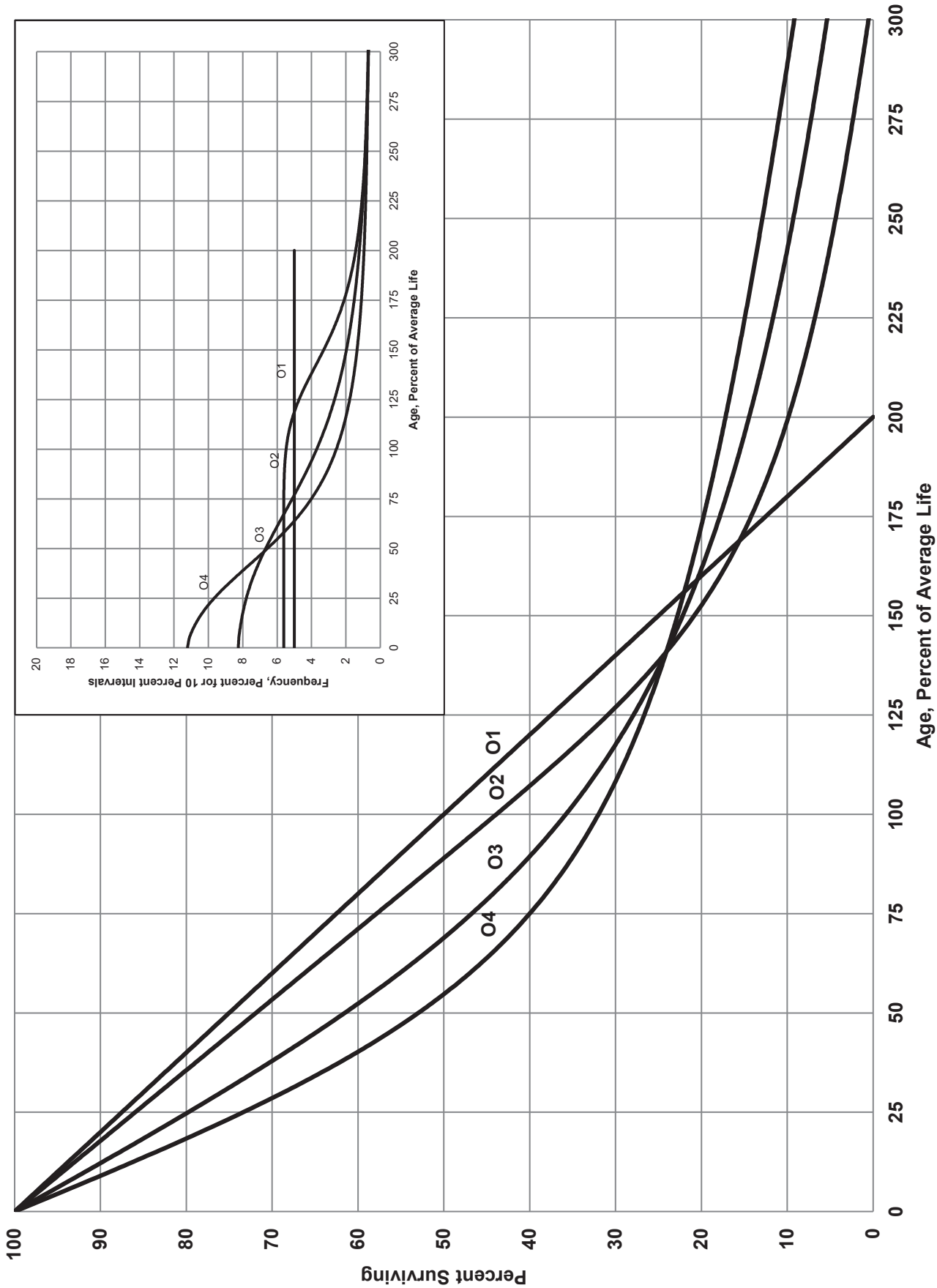


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

---

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2013-2022 for which there were placements during the years 2008-2022. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2008 were retired in 2013. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year

[b] Transfer Affecting Exposures at End of Year

[c] Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2013 through 2022 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2018 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Exposures, Thousands of Dollars Annual Survivors at the Beginning of the Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2013-2022, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2013-2022 Placement Band 2008-2022

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

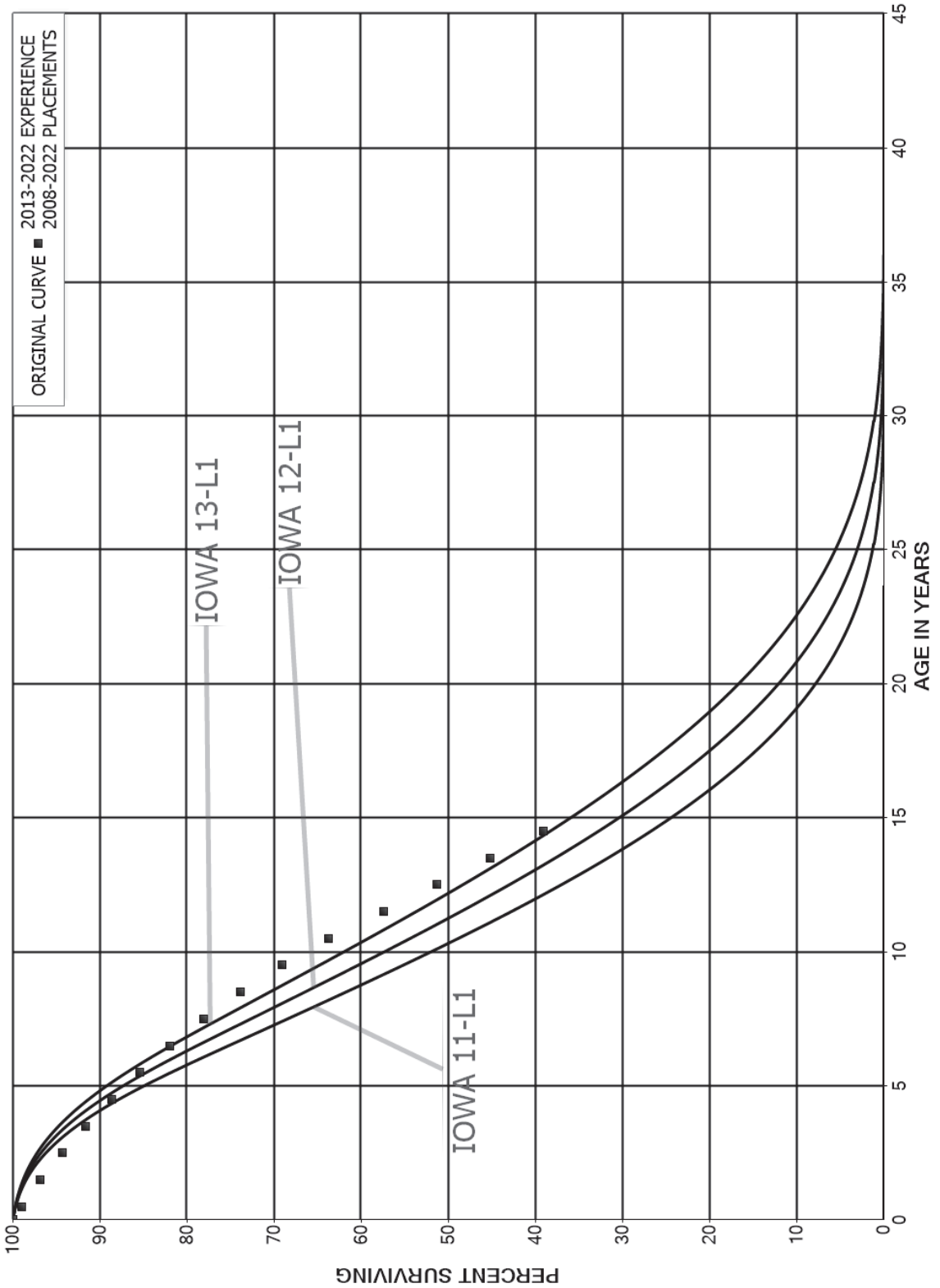


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

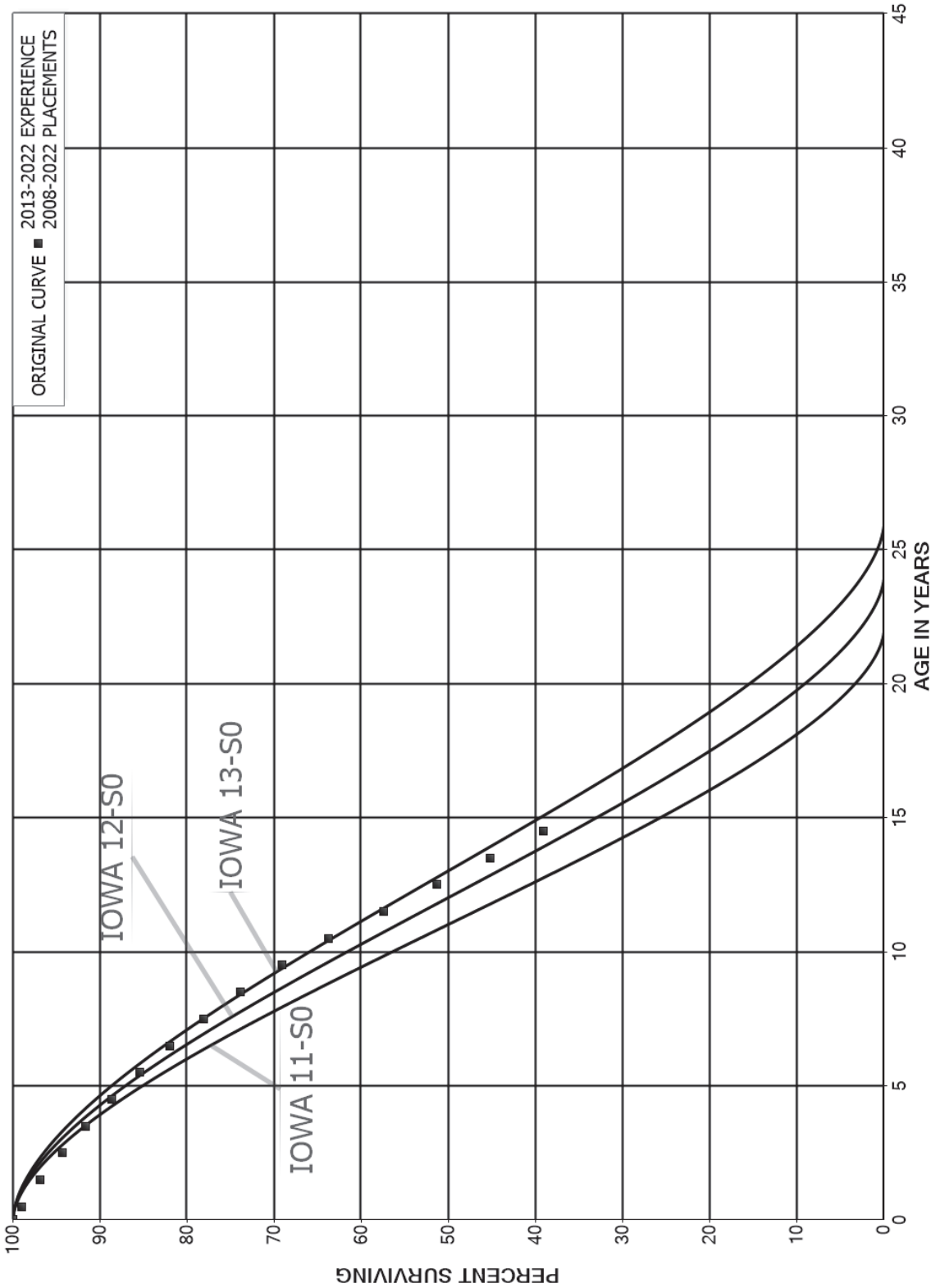


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

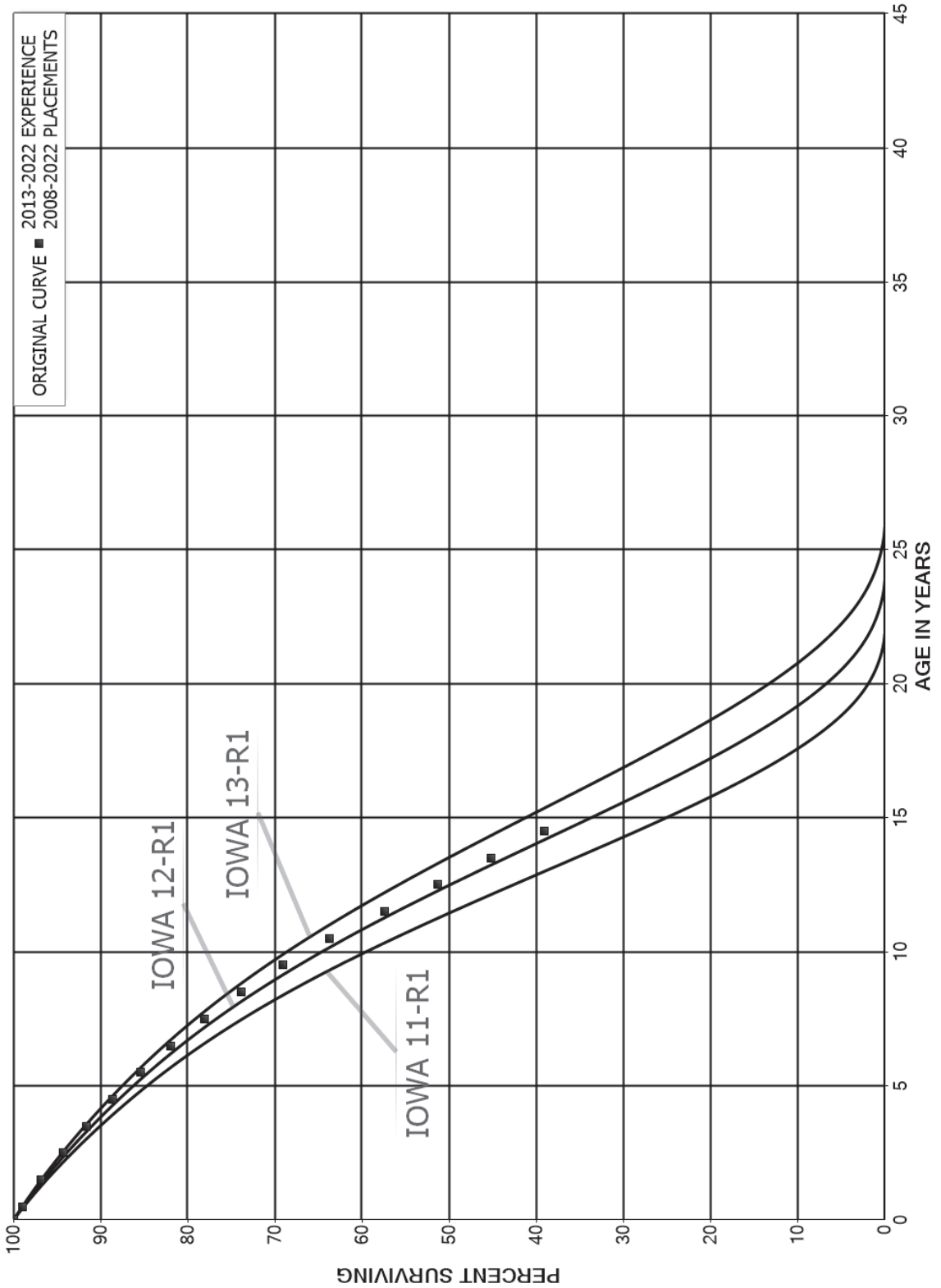
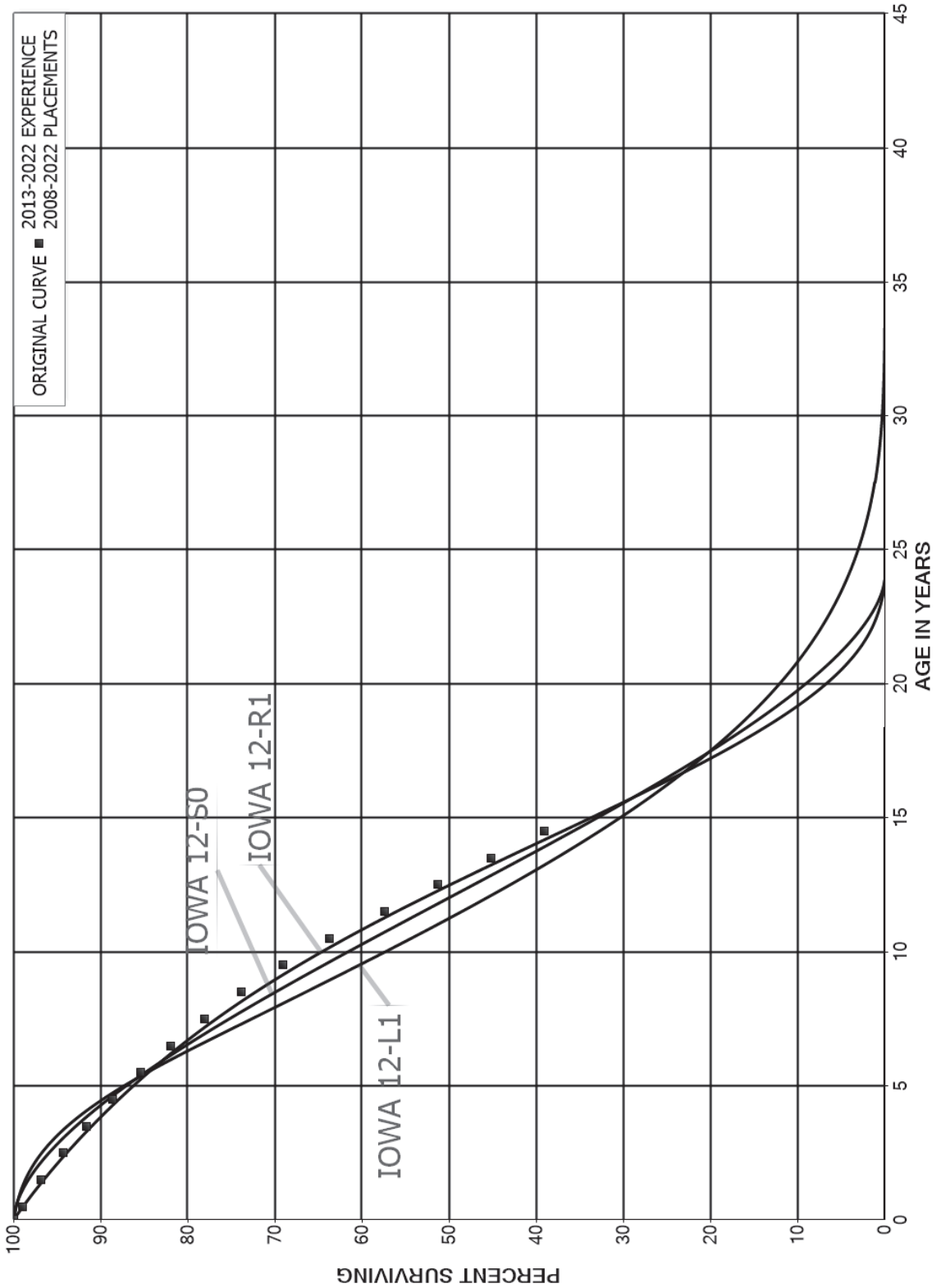


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during our field trip visits.

September 25-26, 2023
- PSEG Electric Training Center
- Metuchen Switching Station
- Pearson Switchyard
- Edison Substation
- Plainfield Substation
- Central Measuring and Regulating Station
- LPA Central Gas Plant
- New Central Measuring and Regulating Station
- Philo Regulating Station
- Woodbridge Measuring and Regulating Station
- New Brunswick Service Center

October 31, 2016
- Essex Substation
- Iron Bound Substation
- Port Street Substation
- Kuller Road Substation
- Great Notch Substation
- Clifton Service Center

SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric and gas utility companies.

For 20 plant accounts for which survivor curves were estimated, the statistical analyses using the retirement rate method contributed significantly to the estimated survivor curves. These accounts represent 86 percent of depreciable electric, gas and common plant. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

ELECTRIC PLANT

DISTRIBUTION PLANT

361.00	Structures and Improvements
362.00	Station Equipment
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
370.00	Meters
373.00	Street Lighting and Signal Systems

GAS PLANT

PRODUCTION PLANT

305.00	Structures and Improvements
307.00	Other Power Equipment
320.00	Other Equipment

OTHER STORAGE PLANT

362.00	Gas Holders

TRANSMISSION PLANT

369.00	Measuring and Regulating Station Equipment

DISTRIBUTION PLANT

375.00	Structures and Improvements
376.00	Mains
380.00	Services
381.00	Meters
382.00	Meter Installations
383.00	House Regulators
384.00	House Regulator Installations
385.00	Industrial Measuring and Regulating Station Equipment

Electric Account 367, Underground Conductors and Devices, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for this account have been compiled for the years 1976 through 2022. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the periods 1976-2022 and 1990-2022. The Iowa 58-R2 is a reasonable fit of the original survivor curve. The 58-year average service life is within the typical range of average service lives used in the industry. The 58-R2 is consistent with Company plans and the assets currently in service for this account

For Gas Plant, Account 376.00, Mains, is used to illustrate the manner in which the study was conducted. Aged plant accounting data have been compiled for the years 1975 through 2022. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the periods 1975-2022 and 1993-2022. The Iowa 75-R2.5 is reasonable fit of many of the data points of the original life table and incorporates that the life table drops to 0 percent surviving by about age 130. The 75-year service life is at the upper end of the typical

service life range of 55 to 75 years for mains. The 75-R2.5 survivor curve incorporates the Company's plans with regard to older types of pipes as well as service life expectations of newer plastic and steel mains.

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric and gas utilities.

The selected amortization periods for most General Plant accounts are described in the section "Calculated Annual and Accrued Depreciation."

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled for the years 1977 through 2022 for electric plant and 1975 through 2022 for gas plant. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 1977 through 2022 for electric plant and 1975 through 2022 for gas plant contributed significantly toward the net salvage estimates for 13 plant accounts, representing 90 percent of depreciable plant, as follows:

ELECTRIC PLANT

DISTRIBUTION PLANT

362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
369.00	Services
370.00	Meters
373.00	Street Lighting and Signal Systems

GAS PLANT

DISTRIBUTION PLANT

376.00	Mains
380.00	Services
381.00	Meters
382.00	Meter Installations
385.00	Industrial Measuring and Regulating Station Equipment

The analysis for Electric Plant Account 367.00, Underground Conductors and Devices, is used to illustrate the manner in which the study was conducted for most plant accounts. Net salvage data for the period 1977 through 2022 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1977-1979 through 2020-2022 periods were computed to smooth the annual amounts.

Cost of removal has varied throughout the forty-six year period but on average has been 69 percent of retirements. Cost of removal for the most recent five years averaged 63 percent. There has been gross salvage in many years for the account. Gross salvage has averaged 25 percent overall and averaged 3 percent in the most recent five years.

The net salvage percent based on the overall period 1977 through 2022 is negative 45 percent and based on the most recent five-year period is negative 60 percent.

Estimates for many other electric utilities for this account are in the negative 5 to negative 25 percent range, although there are many companies with more negative net salvage estimates. The net salvage estimate for PSEG in this account is negative 20, which is conservative when compared to the overall net salvage percent in the historical data, is within the range of other electric company estimates and is consistent with future expectations for this account.

For Gas Plant Account 376.00, Mains, is used to illustrate the manner in which the study was conducted. Net salvage data for the period 1975 through 2022 were analyzed for this account.

Cost of removal has varied throughout the forty-eight year period of available data but has been relatively high throughout the historical period studied. The overall average cost of removal is 63 percent, but recent years have been somewhat lower and the most recent five-year average is 41 percent. Gross salvage has been low throughout the forty-two year period. The overall average is 1 percent.

The average net salvage percent based on the overall period 1975 through 2022 is negative 62 percent and the most recent five-year average is 40 percent. Many estimates for other utilities are in the negative 10 to negative 30 percent range, but there are also estimates of negative 75 percent or higher. It is reasonable to expect that the Company would have higher removal costs than many other utilities, given factors such as a high density population and various work requirements in PSEG's service territory.

The net salvage percents for the remaining accounts were based on judgment incorporating estimates of other electric and gas utilities.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000 \left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2022, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2022, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable electric, gas and common plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
ELECTRIC PLANT		
391.10	Office Furniture	20
391.20	Office Equipment	4
391.31	Office Computer Equipment	7
392.10	Transportation Equipment 13,000 lbs and Under	9
392.20	Transportation Equipment Over 13,000 lbs	13
393.00	Stores Equipment	7
394.00	Tools, Shop and Garage Equipment	7
395.00	Laboratory Equipment	5
396.00	Power Operated Equipment	13
397.00	Communication Equipment	10
398.00	Miscellaneous Equipment	7

GAS PLANT

391.10	Office Furniture and Equipment	20
391.20	Office Equipment	4
391.30	Office Computer Equipment	7
391.33	Personal Computing Equipment	3
392.10	Cars and Light Trucks	9
392.20	Heavy Trucks and Truck Mounted Equipment	13
393.00	Stores Equipment	7
394.00	Tools, Shop and Garage Equipment	7
395.00	Laboratory Equipment	5
396.00	Power Operated Equipment	13
397.00	Communication Equipment	10
398.00	Miscellaneous Equipment	7

The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the original cost by the period of amortization for the account.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric, gas and common plant in service as of December 31, 2022. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2022, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and net salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric and gas utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics."

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s),

when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of net salvage data are presented in the section titled, “Net Salvage Statistics.” The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric, gas and common plant as of December 31, 2022, is presented in Tables 1 and 2 on pages VI-4 through VI-7 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric and gas plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount. Appendix A sets forth the detailed calculation of annual depreciation and annual accrual rates that includes the net normalization method for net salvage. The Appendix includes the calculated depreciation rates with no net salvage component then separately includes the net normalization component for each account.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE		COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)		(10)=(7)/(8)
	ELECTRIC PLANT										
	DISTRIBUTION PLANT										
360.30	SIDEWALKS AND CURBS ON PUBLIC PROPERTY		65-S2.5	0	1,218,246.29	667,958	550,288	11,797	0.97		46.6
361.00	STRUCTURES AND IMPROVEMENTS		70-S1.5	(10)	241,611,849.94	79,369,016	186,404,019	3,590,567	1.49		51.9
362.00	STATION EQUIPMENT		45-S0	(15)	1,563,499,955.95	285,690,218	1,512,334,731	44,203,495	2.83		34.2
364.00	POLES, TOWERS AND FIXTURES		65-R2.5	(80)	1,024,137,859.55	204,387,268	1,639,060,879	36,416,835	3.56		45.0
365.00	OVERHEAD CONDUCTORS AND DEVICES		60-R1	(20)	2,855,533,126.70	614,064,997	2,812,574,755	54,799,572	1.92		51.3
366.00	UNDERGROUND CONDUIT		75-R4	(5)	509,797,650.33	259,019,228	276,268,305	5,252,805	1.03		52.6
367.00	UNDERGROUND CONDUCTORS AND DEVICES		58-R2	(20)	1,461,353,642.60	514,409,209	1,239,215,162	29,166,169	2.00		42.5
368.00	LINE TRANSFORMERS		55-R2	(30)	1,582,143,710.59	380,605,551	1,676,181,273	49,384,525	3.12		33.9
369.00	SERVICES		65-R4	(80)	535,118,075.54	240,771,597	722,440,939	18,874,501	3.53		38.3
370.00	METERS		20-L0.5	(20)	365,421,420.67	82,051,298	356,454,407	28,064,055	7.68		12.7
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		38-R1	(25)	498,983,988.92	118,928,854	504,801,132	18,144,341	3.64		27.8
	TOTAL DISTRIBUTION PLANT				**10,638,819,527.08**	**2,779,965,195**	**10,926,285,890**	**287,908,662**	**2.71**		
	GENERAL PLANT - STRUCTURES AND IMPROVEMENTS										
390.00	STRUCTURES AND IMPROVEMENTS - DISTRIBUTION		55-R2	0	34,060,708.63	4,986,725	29,073,984	612,821	1.80		47.4
	TOTAL STRUCTURES AND IMPROVEMENTS				**34,060,708.63**	**4,986,725**	**29,073,984**	**612,821**	**1.80**		
	GENERAL PLANT - AMORTIZED										
391.10	OFFICE FURNITURE		20-SQ	0	14,686,628.83	14,680,431		734,331	5.00	*	
391.20	OFFICE EQUIPMENT		4-SQ	0	272,720.08	86,133		68,180	25.00	*	
391.31	OFFICE COMPUTER EQUIPMENT		7-SQ	0	13,045,730.89	1,618,653		1,864,235	14.29	*	
392.10	TRANSPORTATION EQUIPMENT 13,000 LBS AND UNDER		9-SQ	0	13,641,107.47	12,292,678		1,515,527	11.11	*	
392.20	TRANSPORTATION EQUIPMENT OVER 13,000 LBS		13-SQ	0	161,495,690.14	79,917,974		12,419,019	7.69	*	
393.00	STORES EQUIPMENT		7-SQ	0	613,067.36	191,456		87,607	14.29	*	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		7-SQ	0	18,295,904.22	9,931,068		2,614,485	14.29	*	
395.00	LABORATORY EQUIPMENT		5-SQ	0	2,933,338.47	1,864,760		586,668	20.00	*	
396.00	POWER OPERATED EQUIPMENT		13-SQ	0	30,192,786.24	14,592,657		2,321,825	7.69	*	
397.00	COMMUNICATION EQUIPMENT		10-SQ	0	66,943,612.98	15,601,419		6,694,361	10.00	*	
398.00	MISCELLANEOUS EQUIPMENT		7-SQ	0	1,738,564.62	1,185,708		248,441	14.29	*	
	GENERAL PLANT - AMORTIZED				**323,859,151.30**	**151,962,938**		**29,154,679**	**9.00**		
	TOTAL DEPRECIABLE ELECTRIC PLANT				**10,996,739,387.01**	**2,936,914,858**	**10,955,359,874**	**317,676,162**	**2.89**		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	COMMON PLANT									
	GENERAL PLANT									
390.00	STRUCTURES AND IMPROVEMENTS									
	PARK PLAZA	06-2041	55-R2	0	42,042,347.28	15,469,678	26,572,669	1,506,683	3.58	17.6
	LEASEHOLD IMPROVEMENTS		55-R2	0	29,397,940.70	12,908,055	16,489,885	317,645	1.08	51.9
	TOTAL COMMON PLANT				**71,440,287.98**	**28,377,734**	**43,062,554**	**1,824,328**	**2.55**	
	TOTAL DEPRECIABLE PLANT				**11,068,179,674.99**	**2,965,292,592**	**10,998,422,428**	**319,500,490**	**2.89**	
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
	ELECTRIC PLANT									
303.00	MISCELLANEOUS INTANGIBLE PLANT				42,442,867.56	16,035,584				
360.00	LAND AND LAND RIGHTS				50,095,922.23	(65)				
389.10	LAND AND LAND RIGHTS				155,022.78	(15,561)				
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED				**92,693,812.57**	**16,019,959**				
	TOTAL ELECTRIC AND COMMON PLANT				**11,160,873,487.56**	**2,981,312,551**				

* ACCRUAL RATE FOR GENERAL PLANT AMORTIZATION ACCOUNTS IS EQUAL TO 1 DIVIDED BY THE AMORTIZATION PERIOD.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

TABLE 2. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GAS PLANT								
	PRODUCTION PLANT								
304.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	55-R3	0	41,238.98	71,265	(30,026)	0	-	-
305.00	STRUCTURES AND IMPROVEMENTS	38-R1.5	(5)	8,358,112.00	10,082,718	(1,306,701)	0	-	-
307.00	OTHER POWER EQUIPMENT	28-R2	(5)	2,877,909.07	2,981,926	39,879	1,448	0.05	27.5
311.00	LIQUEFIED PETROLEUM GAS EQUIPMENT	50-S3	(5)	39,380,160.50	42,370,650	(1,021,482)	0	-	-
320.00	OTHER EQUIPMENT	21-R1	0	227,575.42	579,466	(351,890)	0	-	-
	TOTAL PRODUCTION PLANT			**50,884,995.97**	**56,086,024**	**(2,670,220)**	**1,448**	**0.00**	
	OTHER STORAGE PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	45-R3	0	293,633.92	(82,706)	376,340	8,537	2.91	44.1
362.00	GAS HOLDERS	55-R3	(5)	5,066,482.48	5,066,483	253,324	15,084	0.30	16.8
363.20	VAPORIZING EQUIPMENT	55-S2.5	(5)	8,763,433.13	1,360,102	7,841,503	156,116	1.78	50.2
363.40	MEASURING AND REGULATING STATION EQUIPMENT	55-S2.5	(5)	5,428,187.16	3,271,993	2,427,604	46,712	0.86	52.0
	TOTAL OTHER STORAGE PLANT			**19,551,736.69**	**9,615,871**	**10,898,771**	**226,449**	**1.16**	
	TRANSMISSION PLANT								
367.00	MAINS	70-S2.5	(10)	93,786,846.70	50,016,287	53,149,244	1,122,929	1.20	47.3
369.00	MEASURING AND REGULATING STATION EQUIPMENT	30-S2.5	(10)	4,336,420.46	413,497	4,356,565	665,932	15.36	6.5
	TOTAL TRANSMISSION PLANT			**98,123,267.16**	**50,429,784**	**57,505,809**	**1,788,861**	**1.82**	
	DISTRIBUTION PLANT								
374.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	55-R3	0	54,865.26	29,301	25,565	818	1.49	31.3
375.00	STRUCTURES AND IMPROVEMENTS	60-S2.5	(5)	103,089,212.29	40,268,316	67,975,357	1,441,463	1.40	47.2
376.00	MAINS	75-R2.5	(30)	3,768,890,222.03	1,056,277,834	3,843,279,455	65,241,302	1.73	58.9
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	55-R4	(10)	155,052,903.89	38,926,764	131,631,430	3,121,832	2.01	42.2
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	55-R3	(10)	102,610,302.42	56,393,875	56,477,458	1,617,169	1.58	34.9
380.00	SERVICES	65-R3	(60)	5,364,802,876.79	1,132,262,180	7,451,422,422	140,679,855	2.62	53.0
381.00	METERS	25-L0.5	(10)	477,048,046.87	(61,010,169)	585,763,021	29,698,274	6.23	19.7
382.00	METER INSTALLATIONS	25-L0.5	(10)	52,631,536.57	(33,653,383)	91,548,074	5,289,817	10.05	17.3
383.00	HOUSE REGULATORS	25-L0.5	(5)	38,499,123.37	25,035,791	15,388,288	1,128,034	2.93	13.6
384.00	HOUSE REGULATOR INSTALLATIONS	25-L0.5	(5)	112,683,413.98	58,407,752	59,909,833	3,864,320	3.43	15.5
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	35-R1.5	0	145,614,455.36	25,065,190	120,549,265	4,530,752	3.11	26.6
387.00	OTHER EQUIPMENT	35-S4	0	29,489,886.83	1,416,813	28,073,074	958,027	3.25	29.3
	TOTAL DISTRIBUTION PLANT			**10,350,466,845.66**	**2,339,420,263**	**12,452,043,242**	**257,571,663**	**2.49**	
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	55-R2	0	23,262,931.72	4,150,094	19,112,838	424,132	1.82	45.1
	TOTAL STRUCTURES AND IMPROVEMENTS			23,262,931.72	4,150,094	19,112,838	424,132	1.82	45.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

TABLE 2. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

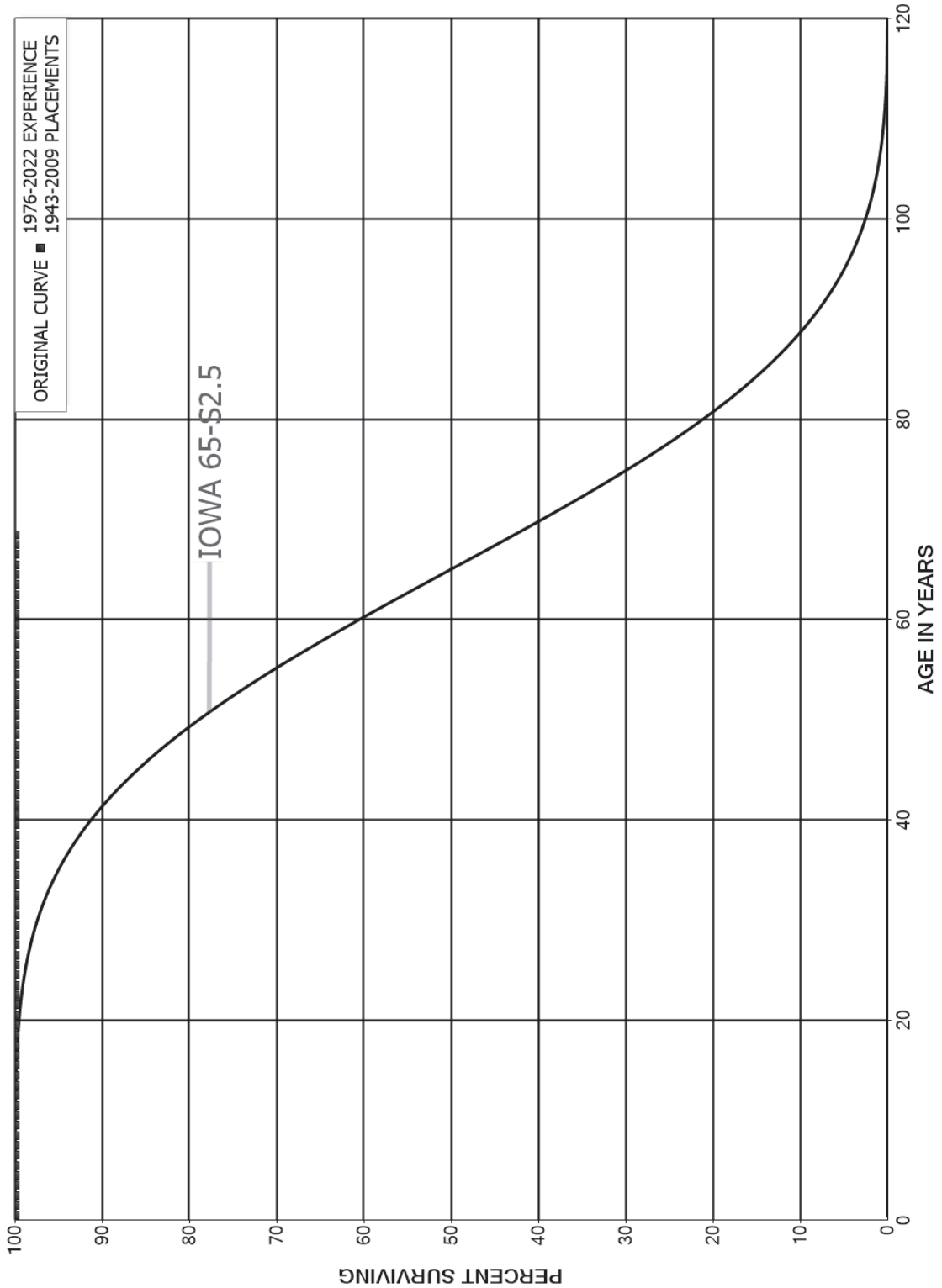
	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE		COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)		(9)=(6)/(7)
	GENERAL PLANT - AMORTIZED									
391.10	OFFICE FURNITURE	20-SQ	0	12,819,389.03	10,350,997		640,969	5.00	*	
391.20	OFFICE EQUIPMENT	4-SQ	0	0.00	(57,538)		0	25.00	*	
391.30	OFFICE COMPUTER EQUIPMENT	7-SQ	0	1,569,512.98	10,144		224,283	14.29	*	
391.33	PERSONAL COMPUTING EQUIPMENT	3-SQ	0	2,516,592.30	1,011,275		838,780	33.33	*	
392.10	CARS AND LIGHT TRUCKS	9-SQ	0	26,749,925.73	21,429,670		2,971,917	11.11	*	
392.20	HEAVY TRUCKS AND TRUCK MOUNTED EQUIPMENT	13-SQ	0	59,281,268.33	24,732,973		4,558,730	7.69	*	
393.00	STORES EQUIPMENT	7-SQ	0	2,362,541.81	1,610,134		337,607	14.29	*	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	7-SQ	0	40,310,338.31	17,310,356		5,760,347	14.29	*	
395.00	LABORATORY EQUIPMENT	5-SQ	0	824,357.78	155,951		164,872	20.00	*	
396.00	POWER OPERATED EQUIPMENT	13-SQ	0	22,244,566.40	10,557,559		1,710,607	7.69	*	
397.00	COMMUNICATION EQUIPMENT	10-SQ	0	6,278,285.39	2,674,354		627,829	10.00	*	
398.00	MISCELLANEOUS EQUIPMENT	7-SQ	0	1,411,781.32	1,037,977		201,744	14.29	*	
	TOTAL GENERAL PLANT - AMORTIZED			**176,368,559.37**	**90,823,851**		**18,037,685**	**10.23**		
	TOTAL GENERAL PLANT			**199,631,491.09**	**94,973,945**		**18,461,817**	**9.25**		
	TOTAL DEPRECIABLE PLANT			**10,718,658,336.57**	**2,550,525,888**	**12,536,890,440**	**278,050,238**	**2.59**		
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
303.00	MISCELLANEOUS INTANGIBLE PLANT			6,228,071.00	1,800,411					
304.00	LAND AND LAND RIGHTS			1,220,370.86						
360.00	LAND			23,496.57						
365.00	LAND AND LAND RIGHTS			5,421,127.53						
374.00	LAND AND LAND RIGHTS			7,185,318.39						
388.00	ARC - DISTRIBUTION PLANT			10,834,324.00						
399.00	ARC - GENERAL PLANT			4,785,231.71						
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**35,697,940.06**	**1,800,411**					
	TOTAL GAS PLANT			**10,754,356,276.63**	**2,552,326,299**					

* ACCRUAL RATE FOR GENERAL PLANT AMORTIZATION ACCOUNTS IS EQUAL TO 1 DIVIDED BY THE AMORTIZATION PERIOD.

PART VII. SERVICE LIFE STATISTICS

ELECTRIC PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-2009 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,089,644		0.0000	1.0000	100.00
0.5	1,105,184		0.0000	1.0000	100.00
1.5	1,110,583		0.0000	1.0000	100.00
2.5	1,114,610		0.0000	1.0000	100.00
3.5	1,114,610		0.0000	1.0000	100.00
4.5	1,114,610		0.0000	1.0000	100.00
5.5	1,125,201		0.0000	1.0000	100.00
6.5	1,125,201		0.0000	1.0000	100.00
7.5	1,153,656		0.0000	1.0000	100.00
8.5	1,157,494		0.0000	1.0000	100.00
9.5	1,164,253		0.0000	1.0000	100.00
10.5	1,170,450		0.0000	1.0000	100.00
11.5	1,170,450		0.0000	1.0000	100.00
12.5	1,173,526		0.0000	1.0000	100.00
13.5	621,044		0.0000	1.0000	100.00
14.5	627,880		0.0000	1.0000	100.00
15.5	627,880		0.0000	1.0000	100.00
16.5	629,564		0.0000	1.0000	100.00
17.5	630,224		0.0000	1.0000	100.00
18.5	635,724		0.0000	1.0000	100.00
19.5	626,472		0.0000	1.0000	100.00
20.5	628,692		0.0000	1.0000	100.00
21.5	645,162		0.0000	1.0000	100.00
22.5	646,935		0.0000	1.0000	100.00
23.5	646,961		0.0000	1.0000	100.00
24.5	344,339		0.0000	1.0000	100.00
25.5	346,823		0.0000	1.0000	100.00
26.5	346,823		0.0000	1.0000	100.00
27.5	346,823		0.0000	1.0000	100.00
28.5	346,823		0.0000	1.0000	100.00
29.5	346,823		0.0000	1.0000	100.00
30.5	284,482		0.0000	1.0000	100.00
31.5	281,138		0.0000	1.0000	100.00
32.5	284,548		0.0000	1.0000	100.00
33.5	280,765		0.0000	1.0000	100.00
34.5	270,076		0.0000	1.0000	100.00
35.5	260,224		0.0000	1.0000	100.00
36.5	223,179		0.0000	1.0000	100.00
37.5	191,482		0.0000	1.0000	100.00
38.5	187,598		0.0000	1.0000	100.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

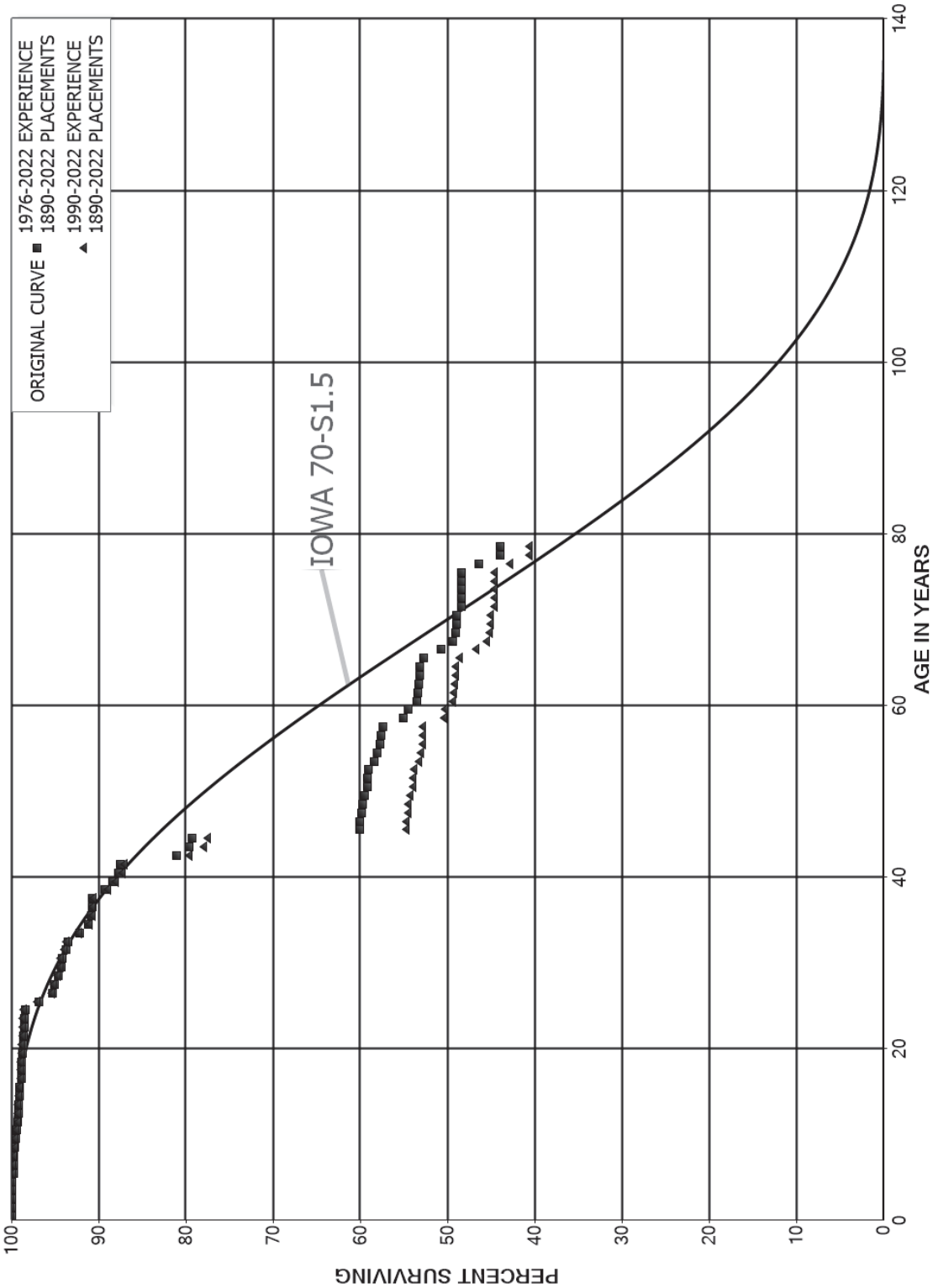
ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-2009 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	178,420		0.0000	1.0000	100.00
40.5	178,420		0.0000	1.0000	100.00
41.5	168,421		0.0000	1.0000	100.00
42.5	160,516		0.0000	1.0000	100.00
43.5	159,544		0.0000	1.0000	100.00
44.5	158,226		0.0000	1.0000	100.00
45.5	140,068		0.0000	1.0000	100.00
46.5	128,603		0.0000	1.0000	100.00
47.5	113,062		0.0000	1.0000	100.00
48.5	107,664		0.0000	1.0000	100.00
49.5	103,636		0.0000	1.0000	100.00
50.5	103,636		0.0000	1.0000	100.00
51.5	103,636		0.0000	1.0000	100.00
52.5	93,046		0.0000	1.0000	100.00
53.5	93,046		0.0000	1.0000	100.00
54.5	64,590		0.0000	1.0000	100.00
55.5	60,752		0.0000	1.0000	100.00
56.5	53,993		0.0000	1.0000	100.00
57.5	47,796		0.0000	1.0000	100.00
58.5	47,796		0.0000	1.0000	100.00
59.5	44,721		0.0000	1.0000	100.00
60.5	44,721		0.0000	1.0000	100.00
61.5	36,361		0.0000	1.0000	100.00
62.5	36,361		0.0000	1.0000	100.00
63.5	34,677		0.0000	1.0000	100.00
64.5	34,016		0.0000	1.0000	100.00
65.5	28,517		0.0000	1.0000	100.00
66.5	28,517		0.0000	1.0000	100.00
67.5	26,297		0.0000	1.0000	100.00
68.5	9,827		0.0000	1.0000	100.00
69.5	8,054		0.0000	1.0000	100.00
70.5	8,028		0.0000	1.0000	100.00
71.5	6,993		0.0000	1.0000	100.00
72.5	4,509		0.0000	1.0000	100.00
73.5	4,509		0.0000	1.0000	100.00
74.5	4,509		0.0000	1.0000	100.00
75.5	4,509		0.0000	1.0000	100.00
76.5	4,509		0.0000	1.0000	100.00
77.5	4,509		0.0000	1.0000	100.00
78.5	4,509		0.0000	1.0000	100.00
79.5					100.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	238,899,145	17,137	0.0001	0.9999	100.00
0.5	251,223,288	6,102	0.0000	1.0000	99.99
1.5	239,169,714	23,777	0.0001	0.9999	99.99
2.5	237,558,530	79,297	0.0003	0.9997	99.98
3.5	223,113,003	3,606	0.0000	1.0000	99.95
4.5	197,242,674	332,065	0.0017	0.9983	99.95
5.5	187,218,498	4,739	0.0000	1.0000	99.78
6.5	182,914,438	186,470	0.0010	0.9990	99.77
7.5	181,125,481	197,091	0.0011	0.9989	99.67
8.5	179,555,800	42,729	0.0002	0.9998	99.56
9.5	179,830,940	181,954	0.0010	0.9990	99.54
10.5	174,784,843	343,928	0.0020	0.9980	99.44
11.5	174,657,538	88,889	0.0005	0.9995	99.24
12.5	174,577,624	26,627	0.0002	0.9998	99.19
13.5	170,389,459	174,762	0.0010	0.9990	99.18
14.5	161,633,250	103,481	0.0006	0.9994	99.08
15.5	155,200,617	260,432	0.0017	0.9983	99.01
16.5	149,549,548	9,352	0.0001	0.9999	98.85
17.5	146,499,394	52,433	0.0004	0.9996	98.84
18.5	146,308,383	141,064	0.0010	0.9990	98.81
19.5	135,592,562	73,447	0.0005	0.9995	98.71
20.5	115,666,216	85,388	0.0007	0.9993	98.66
21.5	111,556,063	105,491	0.0009	0.9991	98.58
22.5	109,030,438	18,494	0.0002	0.9998	98.49
23.5	104,283,228	52,613	0.0005	0.9995	98.47
24.5	98,411,996	1,594,416	0.0162	0.9838	98.42
25.5	95,196,566	1,537,451	0.0162	0.9838	96.83
26.5	92,849,493	204,635	0.0022	0.9978	95.27
27.5	75,399,135	380,907	0.0051	0.9949	95.06
28.5	69,093,548	213,636	0.0031	0.9969	94.58
29.5	63,554,790	47,512	0.0007	0.9993	94.28
30.5	59,347,997	276,101	0.0047	0.9953	94.21
31.5	57,307,674	160,669	0.0028	0.9972	93.77
32.5	55,896,609	773,953	0.0138	0.9862	93.51
33.5	45,865,882	533,566	0.0116	0.9884	92.22
34.5	33,527,658	131,204	0.0039	0.9961	91.14
35.5	31,865,232	9,846	0.0003	0.9997	90.79
36.5	28,099,832	16,706	0.0006	0.9994	90.76
37.5	26,214,035	423,769	0.0162	0.9838	90.71
38.5	25,086,195	226,439	0.0090	0.9910	89.24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	22,921,103	193,461	0.0084	0.9916	88.43
40.5	20,255,957	49,349	0.0024	0.9976	87.69
41.5	19,475,887	1,428,194	0.0733	0.9267	87.47
42.5	17,146,978	310,611	0.0181	0.9819	81.06
43.5	16,527,565	73,532	0.0044	0.9956	79.59
44.5	14,926,488	3,603,652	0.2414	0.7586	79.24
45.5	9,560,385	13,544	0.0014	0.9986	60.11
46.5	8,703,670	33,180	0.0038	0.9962	60.02
47.5	7,034,325	8,782	0.0012	0.9988	59.79
48.5	6,448,753	26,616	0.0041	0.9959	59.72
49.5	6,104,331	30,043	0.0049	0.9951	59.47
50.5	5,845,269	4,878	0.0008	0.9992	59.18
51.5	5,707,056	10,653	0.0019	0.9981	59.13
52.5	5,611,607	58,634	0.0104	0.9896	59.02
53.5	5,336,653	34,708	0.0065	0.9935	58.40
54.5	5,183,247	27,232	0.0053	0.9947	58.02
55.5	5,020,313	13,155	0.0026	0.9974	57.72
56.5	5,101,289	10,701	0.0021	0.9979	57.57
57.5	5,183,742	213,487	0.0412	0.9588	57.45
58.5	4,986,726	48,906	0.0098	0.9902	55.08
59.5	4,793,059	87,767	0.0183	0.9817	54.54
60.5	4,397,202	12,532	0.0029	0.9971	53.54
61.5	4,175,592	4,456	0.0011	0.9989	53.39
62.5	4,123,469	8,021	0.0019	0.9981	53.33
63.5	4,047,638	868	0.0002	0.9998	53.23
64.5	3,996,636	34,091	0.0085	0.9915	53.22
65.5	3,664,126	144,767	0.0395	0.9605	52.76
66.5	3,280,140	83,697	0.0255	0.9745	50.68
67.5	2,990,535	20,189	0.0068	0.9932	49.38
68.5	2,769,361	3,586	0.0013	0.9987	49.05
69.5	2,653,224		0.0000	1.0000	48.99
70.5	2,554,105	28,141	0.0110	0.9890	48.99
71.5	2,384,467		0.0000	1.0000	48.45
72.5	2,361,045		0.0000	1.0000	48.45
73.5	2,349,963		0.0000	1.0000	48.45
74.5	2,364,573	4,551	0.0019	0.9981	48.45
75.5	2,389,840	98,422	0.0412	0.9588	48.36
76.5	2,267,712	118,118	0.0521	0.9479	46.36
77.5	2,139,500	454	0.0002	0.9998	43.95
78.5	2,139,046	4,000	0.0019	0.9981	43.94

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	85,893		0.0000	1.0000	43.86
80.5	85,893		0.0000	1.0000	43.86
81.5	101,914	12,167	0.1194	0.8806	43.86
82.5	89,747		0.0000	1.0000	38.62
83.5	89,747		0.0000	1.0000	38.62
84.5	29,434		0.0000	1.0000	38.62
85.5	221,404		0.0000	1.0000	38.62
86.5	250,859	26,466	0.1055	0.8945	38.62
87.5	224,393		0.0000	1.0000	34.55
88.5	224,393		0.0000	1.0000	34.55
89.5	224,393		0.0000	1.0000	34.55
90.5	194,938		0.0000	1.0000	34.55
91.5	194,938		0.0000	1.0000	34.55
92.5	178,916		0.0000	1.0000	34.55
93.5	178,916		0.0000	1.0000	34.55
94.5	168,022		0.0000	1.0000	34.55
95.5	168,022		0.0000	1.0000	34.55
96.5	168,022		0.0000	1.0000	34.55
97.5	165,504		0.0000	1.0000	34.55
98.5	165,504		0.0000	1.0000	34.55
99.5	165,504		0.0000	1.0000	34.55
100.5	165,504		0.0000	1.0000	34.55
101.5	165,504	165,504	1.0000		34.55
102.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	195,073,479		0.0000	1.0000	100.00
0.5	212,263,242	6,102	0.0000	1.0000	100.00
1.5	212,552,264	21,032	0.0001	0.9999	100.00
2.5	212,498,069	74,683	0.0004	0.9996	99.99
3.5	202,249,341	3,606	0.0000	1.0000	99.95
4.5	178,324,818	305,809	0.0017	0.9983	99.95
5.5	169,051,985	134	0.0000	1.0000	99.78
6.5	166,724,925	184,903	0.0011	0.9989	99.78
7.5	167,685,888	196,355	0.0012	0.9988	99.67
8.5	167,261,946	32,639	0.0002	0.9998	99.55
9.5	168,074,939	174,104	0.0010	0.9990	99.53
10.5	163,270,935	337,333	0.0021	0.9979	99.43
11.5	165,278,364	86,175	0.0005	0.9995	99.22
12.5	166,608,073	12,526	0.0001	0.9999	99.17
13.5	162,936,683	173,485	0.0011	0.9989	99.16
14.5	158,992,209	103,481	0.0007	0.9993	99.06
15.5	153,106,163	207,613	0.0014	0.9986	98.99
16.5	147,146,432	7,834	0.0001	0.9999	98.86
17.5	144,275,536	49,553	0.0003	0.9997	98.85
18.5	143,923,040	131,643	0.0009	0.9991	98.82
19.5	133,142,998	66,222	0.0005	0.9995	98.73
20.5	113,266,171	69,082	0.0006	0.9994	98.68
21.5	109,220,081	12,211	0.0001	0.9999	98.62
22.5	106,846,247	18,460	0.0002	0.9998	98.61
23.5	102,319,077	52,613	0.0005	0.9995	98.59
24.5	96,588,997	1,592,516	0.0165	0.9835	98.54
25.5	93,422,038	1,526,816	0.0163	0.9837	96.92
26.5	91,100,596	204,485	0.0022	0.9978	95.33
27.5	73,774,063	380,535	0.0052	0.9948	95.12
28.5	67,667,233	211,871	0.0031	0.9969	94.63
29.5	61,888,259	45,747	0.0007	0.9993	94.33
30.5	57,802,260	275,807	0.0048	0.9952	94.26
31.5	55,711,745	149,021	0.0027	0.9973	93.81
32.5	52,093,383	773,953	0.0149	0.9851	93.56
33.5	42,225,211	533,532	0.0126	0.9874	92.17
34.5	30,201,904	130,948	0.0043	0.9957	91.01
35.5	28,830,019	7,882	0.0003	0.9997	90.61
36.5	25,156,759	16,613	0.0007	0.9993	90.59
37.5	23,358,948	423,769	0.0181	0.9819	90.53
38.5	22,354,396	225,817	0.0101	0.9899	88.89

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,201,767	189,378	0.0094	0.9906	87.99
40.5	17,561,555	49,202	0.0028	0.9972	87.16
41.5	16,779,802	1,427,746	0.0851	0.9149	86.92
42.5	14,455,517	307,581	0.0213	0.9787	79.52
43.5	13,834,449	73,532	0.0053	0.9947	77.83
44.5	12,256,260	3,601,878	0.2939	0.7061	77.42
45.5	6,914,046	12,703	0.0018	0.9982	54.67
46.5	8,582,005	22,291	0.0026	0.9974	54.57
47.5	6,885,046	8,782	0.0013	0.9987	54.42
48.5	6,291,760	26,616	0.0042	0.9958	54.35
49.5	5,964,057	30,043	0.0050	0.9950	54.12
50.5	5,712,919	4,878	0.0009	0.9991	53.85
51.5	5,499,071	10,653	0.0019	0.9981	53.81
52.5	5,409,744	57,678	0.0107	0.9893	53.70
53.5	5,178,795	16,264	0.0031	0.9969	53.13
54.5	4,945,157	21,158	0.0043	0.9957	52.96
55.5	4,667,299		0.0000	1.0000	52.74
56.5	4,621,430	2,168	0.0005	0.9995	52.74
57.5	4,549,566	213,487	0.0469	0.9531	52.71
58.5	4,273,290	744	0.0002	0.9998	50.24
59.5	4,240,519	80,234	0.0189	0.9811	50.23
60.5	4,000,742	12,532	0.0031	0.9969	49.28
61.5	3,970,950	3,016	0.0008	0.9992	49.12
62.5	3,964,724	8,021	0.0020	0.9980	49.09
63.5	3,925,870	868	0.0002	0.9998	48.99
64.5	3,889,411	34,091	0.0088	0.9912	48.98
65.5	3,588,606	144,767	0.0403	0.9597	48.55
66.5	3,208,206	83,697	0.0261	0.9739	46.59
67.5	2,918,600	20,189	0.0069	0.9931	45.37
68.5	2,680,531	3,586	0.0013	0.9987	45.06
69.5	2,554,980		0.0000	1.0000	45.00
70.5	2,484,123	28,141	0.0113	0.9887	45.00
71.5	2,359,710		0.0000	1.0000	44.49
72.5	2,337,715		0.0000	1.0000	44.49
73.5	2,337,715		0.0000	1.0000	44.49
74.5	2,346,774		0.0000	1.0000	44.49
75.5	2,347,557	91,684	0.0391	0.9609	44.49
76.5	2,255,873	118,118	0.0524	0.9476	42.75
77.5	2,128,116	454	0.0002	0.9998	40.51
78.5	2,127,662	4,000	0.0019	0.9981	40.50

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

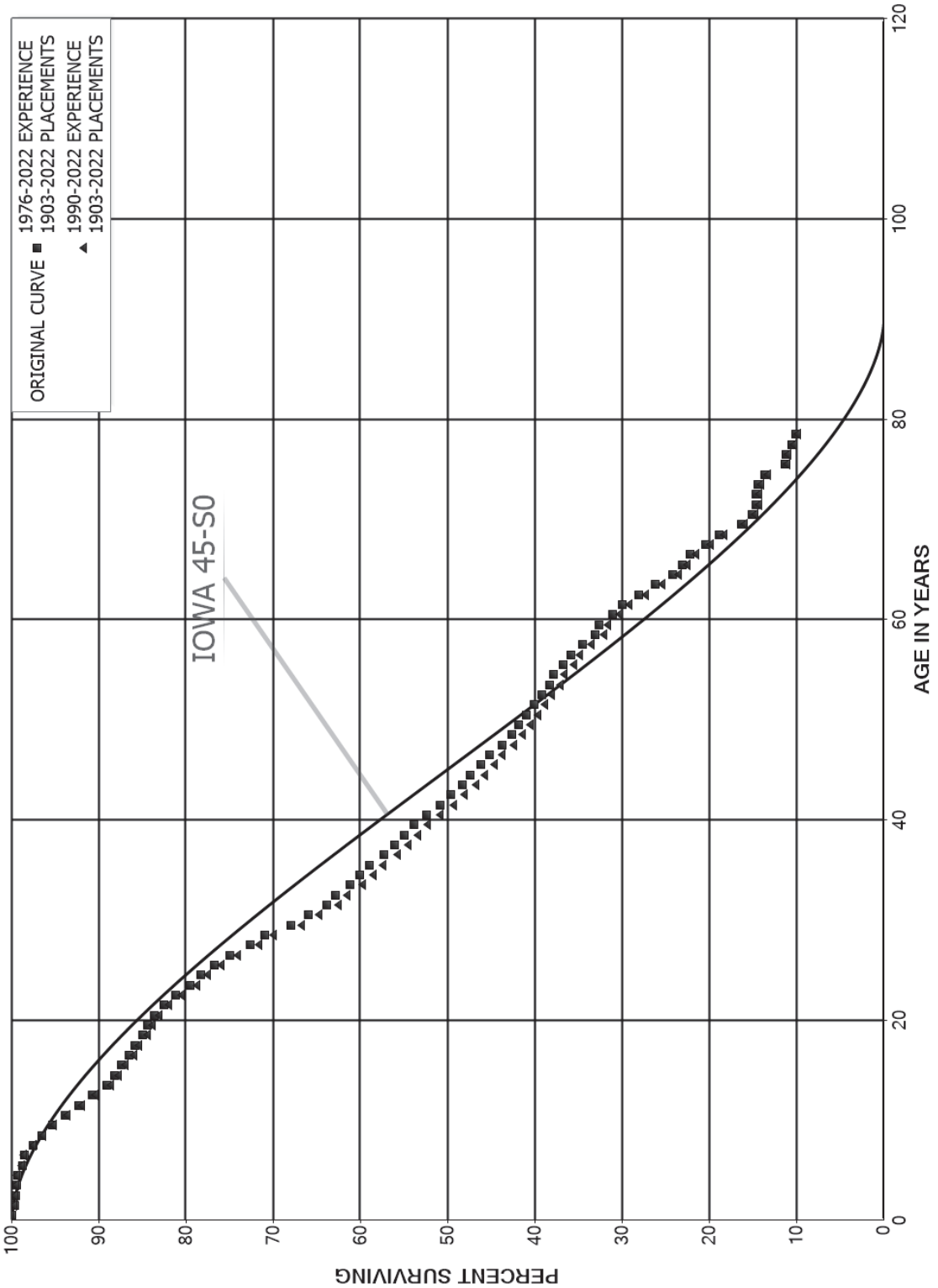
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	85,893		0.0000	1.0000	40.43
80.5	85,893		0.0000	1.0000	40.43
81.5	85,893	12,167	0.1417	0.8583	40.43
82.5	73,726		0.0000	1.0000	34.70
83.5	73,726		0.0000	1.0000	34.70
84.5	13,413		0.0000	1.0000	34.70
85.5	13,413		0.0000	1.0000	34.70
86.5	29,434		0.0000	1.0000	34.70
87.5	29,434		0.0000	1.0000	34.70
88.5	29,434		0.0000	1.0000	34.70
89.5	29,434		0.0000	1.0000	34.70
90.5	29,434		0.0000	1.0000	34.70
91.5	29,434		0.0000	1.0000	34.70
92.5	13,413		0.0000	1.0000	34.70
93.5	13,413		0.0000	1.0000	34.70
94.5	2,519		0.0000	1.0000	34.70
95.5	2,519		0.0000	1.0000	34.70
96.5	2,519		0.0000	1.0000	34.70
97.5					34.70
98.5					
99.5	165,504		0.0000		
100.5	165,504		0.0000		
101.5	165,504	165,504	1.0000		
102.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,613,588,750	1,310,345	0.0008	0.9992	100.00
0.5	1,612,250,501	4,205,545	0.0026	0.9974	99.92
1.5	1,478,959,418	2,573,259	0.0017	0.9983	99.66
2.5	1,447,517,639	1,595,318	0.0011	0.9989	99.48
3.5	1,400,234,727	1,492,468	0.0011	0.9989	99.38
4.5	1,225,988,980	6,351,002	0.0052	0.9948	99.27
5.5	1,048,786,846	2,309,860	0.0022	0.9978	98.75
6.5	862,092,298	8,926,924	0.0104	0.9896	98.54
7.5	780,083,511	8,062,235	0.0103	0.9897	97.52
8.5	760,867,859	9,261,198	0.0122	0.9878	96.51
9.5	730,528,500	11,204,045	0.0153	0.9847	95.33
10.5	705,983,416	11,976,379	0.0170	0.9830	93.87
11.5	686,437,170	11,218,354	0.0163	0.9837	92.28
12.5	670,884,975	12,295,624	0.0183	0.9817	90.77
13.5	607,658,451	6,603,200	0.0109	0.9891	89.11
14.5	586,153,716	5,008,836	0.0085	0.9915	88.14
15.5	568,183,646	5,759,524	0.0101	0.9899	87.39
16.5	563,039,226	4,152,391	0.0074	0.9926	86.50
17.5	557,279,279	6,114,594	0.0110	0.9890	85.86
18.5	541,418,226	3,371,737	0.0062	0.9938	84.92
19.5	518,643,875	4,957,200	0.0096	0.9904	84.39
20.5	487,736,378	6,080,034	0.0125	0.9875	83.59
21.5	477,903,337	8,056,228	0.0169	0.9831	82.54
22.5	468,216,911	9,654,669	0.0206	0.9794	81.15
23.5	457,461,595	7,080,845	0.0155	0.9845	79.48
24.5	425,079,721	8,169,396	0.0192	0.9808	78.25
25.5	404,745,489	9,485,673	0.0234	0.9766	76.74
26.5	387,421,053	12,060,680	0.0311	0.9689	74.95
27.5	372,681,205	8,319,254	0.0223	0.9777	72.61
28.5	347,565,381	15,049,627	0.0433	0.9567	70.99
29.5	320,022,383	9,240,431	0.0289	0.9711	67.92
30.5	285,358,482	9,228,421	0.0323	0.9677	65.96
31.5	271,859,034	4,083,193	0.0150	0.9850	63.82
32.5	255,718,776	7,062,267	0.0276	0.9724	62.87
33.5	219,059,401	3,998,342	0.0183	0.9817	61.13
34.5	202,646,158	3,761,997	0.0186	0.9814	60.01
35.5	188,284,680	5,328,111	0.0283	0.9717	58.90
36.5	175,833,729	3,684,073	0.0210	0.9790	57.23
37.5	167,027,618	3,310,667	0.0198	0.9802	56.03
38.5	159,022,560	3,228,953	0.0203	0.9797	54.92

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	152,669,313	3,913,370	0.0256	0.9744	53.81
40.5	143,801,812	4,439,164	0.0309	0.9691	52.43
41.5	136,792,528	3,270,647	0.0239	0.9761	50.81
42.5	128,346,986	3,362,021	0.0262	0.9738	49.59
43.5	123,025,367	2,425,068	0.0197	0.9803	48.30
44.5	114,733,944	2,779,300	0.0242	0.9758	47.34
45.5	108,781,292	2,495,567	0.0229	0.9771	46.20
46.5	102,055,667	3,189,014	0.0312	0.9688	45.14
47.5	90,519,411	2,196,477	0.0243	0.9757	43.73
48.5	83,593,070	1,711,487	0.0205	0.9795	42.67
49.5	76,275,042	1,630,809	0.0214	0.9786	41.79
50.5	71,912,824	1,395,195	0.0194	0.9806	40.90
51.5	68,692,816	1,500,126	0.0218	0.9782	40.11
52.5	65,634,141	1,587,353	0.0242	0.9758	39.23
53.5	62,156,196	802,203	0.0129	0.9871	38.28
54.5	56,705,245	1,650,790	0.0291	0.9709	37.79
55.5	52,593,411	1,200,414	0.0228	0.9772	36.69
56.5	50,618,832	1,843,925	0.0364	0.9636	35.85
57.5	47,085,643	2,052,132	0.0436	0.9564	34.54
58.5	44,156,151	600,516	0.0136	0.9864	33.04
59.5	42,029,308	1,927,662	0.0459	0.9541	32.59
60.5	37,855,038	1,343,331	0.0355	0.9645	31.09
61.5	34,688,957	2,272,608	0.0655	0.9345	29.99
62.5	31,016,153	2,100,126	0.0677	0.9323	28.03
63.5	27,441,440	2,036,956	0.0742	0.9258	26.13
64.5	22,693,392	1,031,023	0.0454	0.9546	24.19
65.5	20,094,231	827,370	0.0412	0.9588	23.09
66.5	18,119,270	1,414,714	0.0781	0.9219	22.14
67.5	14,163,123	1,096,196	0.0774	0.9226	20.41
68.5	9,775,291	1,297,808	0.1328	0.8672	18.83
69.5	6,632,773	507,409	0.0765	0.9235	16.33
70.5	4,767,490	141,176	0.0296	0.9704	15.08
71.5	4,438,760	7,689	0.0017	0.9983	14.63
72.5	4,290,922	53,349	0.0124	0.9876	14.61
73.5	4,223,979	243,675	0.0577	0.9423	14.43
74.5	3,934,670	654,033	0.1662	0.8338	13.60
75.5	3,268,783	50,889	0.0156	0.9844	11.34
76.5	3,207,818	174,842	0.0545	0.9455	11.16
77.5	3,020,524	129,848	0.0430	0.9570	10.55
78.5	2,880,918	114,566	0.0398	0.9602	10.10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	945,079	117,337	0.1242	0.8758	9.70
80.5	767,972	123,458	0.1608	0.8392	8.49
81.5	640,703	23	0.0000	1.0000	7.13
82.5	561,785	60,611	0.1079	0.8921	7.13
83.5	490,332		0.0000	1.0000	6.36
84.5	356,440	1,900	0.0053	0.9947	6.36
85.5	329,051	1,928	0.0059	0.9941	6.32
86.5	327,123	111,780	0.3417	0.6583	6.29
87.5	215,343		0.0000	1.0000	4.14
88.5	215,343		0.0000	1.0000	4.14
89.5	215,343	1,763	0.0082	0.9918	4.14
90.5	213,580		0.0000	1.0000	4.10
91.5	139,053	1,677	0.0121	0.9879	4.10
92.5	130,394	8,137	0.0624	0.9376	4.06
93.5	99,933		0.0000	1.0000	3.80
94.5	32,766		0.0000	1.0000	3.80
95.5	32,766		0.0000	1.0000	3.80
96.5	16,223		0.0000	1.0000	3.80
97.5					3.80

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,450,066,932	888,001	0.0006	0.9994	100.00
0.5	1,487,454,088	4,202,047	0.0028	0.9972	99.94
1.5	1,371,691,000	2,534,337	0.0018	0.9982	99.66
2.5	1,352,332,194	1,395,353	0.0010	0.9990	99.47
3.5	1,317,870,483	1,458,494	0.0011	0.9989	99.37
4.5	1,153,229,576	6,313,311	0.0055	0.9945	99.26
5.5	981,890,785	2,199,853	0.0022	0.9978	98.72
6.5	800,999,550	8,870,563	0.0111	0.9889	98.50
7.5	722,201,633	7,935,856	0.0110	0.9890	97.40
8.5	710,050,271	9,225,915	0.0130	0.9870	96.33
9.5	684,204,840	11,148,723	0.0163	0.9837	95.08
10.5	658,535,212	11,892,809	0.0181	0.9819	93.53
11.5	642,623,135	11,036,463	0.0172	0.9828	91.84
12.5	629,844,432	12,069,963	0.0192	0.9808	90.27
13.5	569,325,171	6,224,870	0.0109	0.9891	88.54
14.5	553,232,282	4,803,456	0.0087	0.9913	87.57
15.5	539,569,969	5,733,344	0.0106	0.9894	86.81
16.5	537,990,292	3,950,426	0.0073	0.9927	85.89
17.5	531,623,161	6,086,383	0.0114	0.9886	85.26
18.5	514,864,660	3,218,672	0.0063	0.9937	84.28
19.5	491,896,604	4,858,699	0.0099	0.9901	83.75
20.5	459,267,330	5,989,184	0.0130	0.9870	82.93
21.5	450,737,020	7,933,097	0.0176	0.9824	81.84
22.5	441,076,878	9,535,699	0.0216	0.9784	80.40
23.5	429,421,800	7,033,133	0.0164	0.9836	78.66
24.5	397,411,043	7,963,946	0.0200	0.9800	77.38
25.5	377,470,067	9,300,828	0.0246	0.9754	75.83
26.5	360,723,693	11,824,865	0.0328	0.9672	73.96
27.5	347,156,425	8,193,693	0.0236	0.9764	71.53
28.5	322,891,815	14,843,422	0.0460	0.9540	69.84
29.5	296,610,584	8,952,092	0.0302	0.9698	66.63
30.5	261,776,459	9,072,809	0.0347	0.9653	64.62
31.5	251,205,514	4,002,633	0.0159	0.9841	62.38
32.5	232,979,181	6,929,035	0.0297	0.9703	61.39
33.5	198,603,931	3,843,560	0.0194	0.9806	59.56
34.5	186,396,142	3,701,183	0.0199	0.9801	58.41
35.5	174,902,670	5,155,871	0.0295	0.9705	57.25
36.5	164,210,048	3,456,431	0.0210	0.9790	55.56
37.5	157,346,770	3,298,462	0.0210	0.9790	54.39
38.5	150,831,339	3,135,310	0.0208	0.9792	53.25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	145,771,308	3,871,717	0.0266	0.9734	52.15
40.5	137,406,338	4,429,231	0.0322	0.9678	50.76
41.5	130,403,570	3,269,929	0.0251	0.9749	49.13
42.5	121,971,988	3,278,578	0.0269	0.9731	47.89
43.5	116,687,953	2,410,028	0.0207	0.9793	46.61
44.5	108,304,861	2,728,968	0.0252	0.9748	45.64
45.5	102,469,267	2,048,778	0.0200	0.9800	44.49
46.5	101,671,101	3,155,871	0.0310	0.9690	43.60
47.5	89,894,425	2,154,362	0.0240	0.9760	42.25
48.5	83,001,031	1,703,667	0.0205	0.9795	41.24
49.5	75,812,412	1,626,941	0.0215	0.9785	40.39
50.5	71,471,367	1,394,619	0.0195	0.9805	39.52
51.5	68,257,252	1,498,353	0.0220	0.9780	38.75
52.5	65,299,988	1,583,463	0.0242	0.9758	37.90
53.5	61,751,328	788,406	0.0128	0.9872	36.98
54.5	56,249,664	1,640,383	0.0292	0.9708	36.51
55.5	51,812,574	1,133,131	0.0219	0.9781	35.45
56.5	49,767,345	1,817,770	0.0365	0.9635	34.67
57.5	45,797,553	2,028,512	0.0443	0.9557	33.40
58.5	42,787,510	550,431	0.0129	0.9871	31.93
59.5	40,782,372	1,766,695	0.0433	0.9567	31.51
60.5	37,004,585	1,318,671	0.0356	0.9644	30.15
61.5	34,169,070	2,255,611	0.0660	0.9340	29.08
62.5	30,713,588	2,094,612	0.0682	0.9318	27.16
63.5	27,312,624	2,036,956	0.0746	0.9254	25.30
64.5	22,666,684	1,029,490	0.0454	0.9546	23.42
65.5	20,091,309	827,370	0.0412	0.9588	22.35
66.5	18,116,943	1,414,714	0.0781	0.9219	21.43
67.5	14,162,467	1,096,196	0.0774	0.9226	19.76
68.5	9,774,635	1,297,808	0.1328	0.8672	18.23
69.5	6,632,116	507,409	0.0765	0.9235	15.81
70.5	4,766,834	141,130	0.0296	0.9704	14.60
71.5	4,438,149	7,689	0.0017	0.9983	14.17
72.5	4,290,311	53,349	0.0124	0.9876	14.14
73.5	4,223,368	243,675	0.0577	0.9423	13.97
74.5	3,934,238	654,033	0.1662	0.8338	13.16
75.5	3,267,199	49,305	0.0151	0.9849	10.97
76.5	3,207,818	174,842	0.0545	0.9455	10.81
77.5	3,020,524	129,848	0.0430	0.9570	10.22
78.5	2,880,895	114,566	0.0398	0.9602	9.78

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

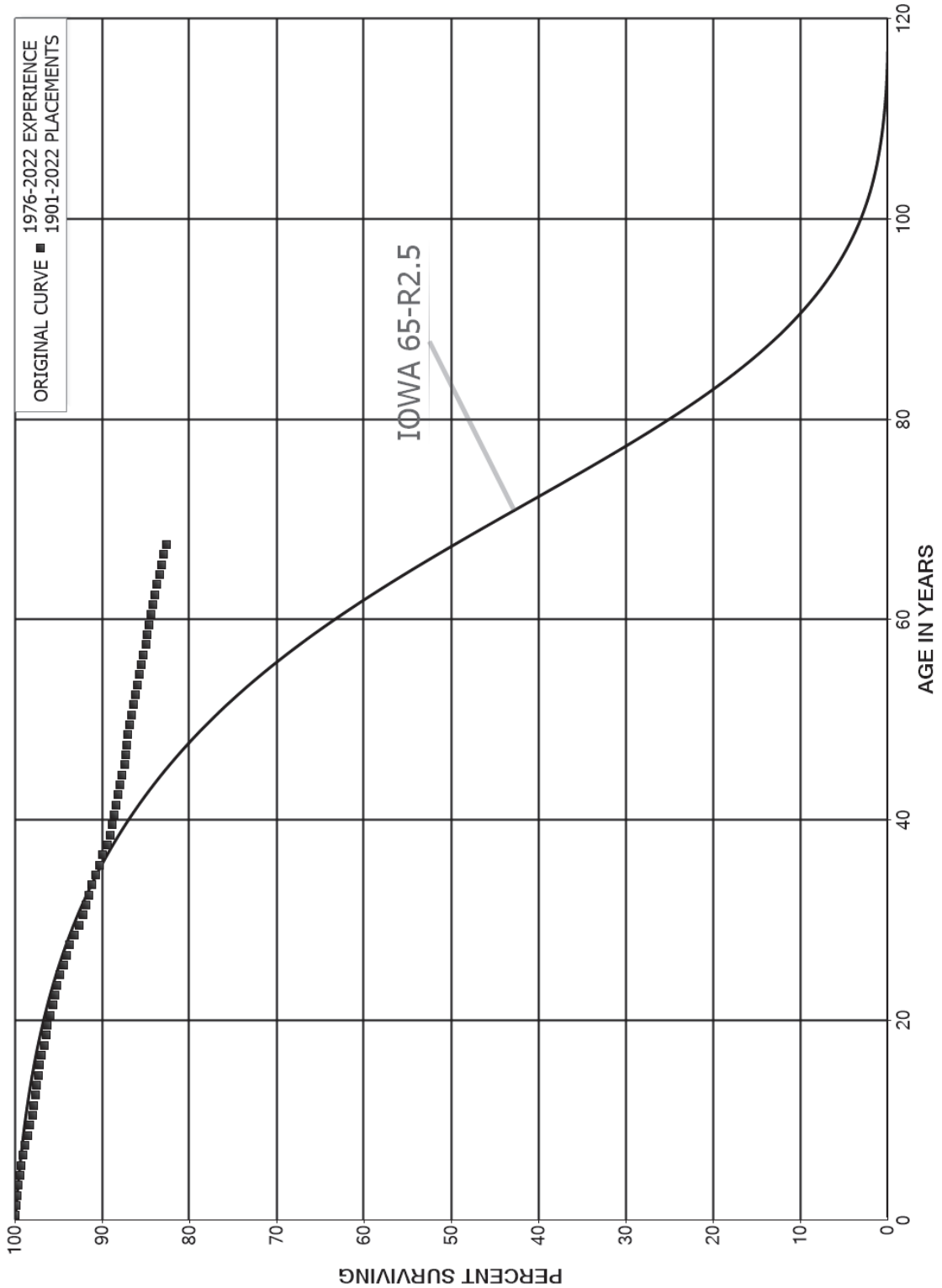
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	945,055	117,337	0.1242	0.8758	9.39
80.5	767,949	123,458	0.1608	0.8392	8.22
81.5	639,003		0.0000	1.0000	6.90
82.5	560,109	60,611	0.1082	0.8918	6.90
83.5	488,656		0.0000	1.0000	6.16
84.5	354,764	1,900	0.0054	0.9946	6.16
85.5	327,375	1,928	0.0059	0.9941	6.12
86.5	327,123	111,780	0.3417	0.6583	6.09
87.5	215,343		0.0000	1.0000	4.01
88.5	215,343		0.0000	1.0000	4.01
89.5	215,343	1,763	0.0082	0.9918	4.01
90.5	213,580		0.0000	1.0000	3.97
91.5	139,053	1,677	0.0121	0.9879	3.97
92.5	130,394	8,137	0.0624	0.9376	3.93
93.5	99,933		0.0000	1.0000	3.68
94.5	32,766		0.0000	1.0000	3.68
95.5	32,766		0.0000	1.0000	3.68
96.5	16,223		0.0000	1.0000	3.68
97.5					3.68

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	976,471,431	587,657	0.0006	0.9994	100.00
0.5	904,688,576	1,218,055	0.0013	0.9987	99.94
1.5	874,305,509	981,796	0.0011	0.9989	99.81
2.5	834,953,571	1,041,090	0.0012	0.9988	99.69
3.5	790,636,386	1,066,662	0.0013	0.9987	99.57
4.5	754,060,417	1,428,243	0.0019	0.9981	99.43
5.5	732,805,676	1,154,627	0.0016	0.9984	99.25
6.5	717,880,774	1,650,987	0.0023	0.9977	99.09
7.5	689,997,954	2,513,086	0.0036	0.9964	98.86
8.5	674,656,450	1,660,358	0.0025	0.9975	98.50
9.5	638,879,058	1,673,529	0.0026	0.9974	98.26
10.5	612,293,667	1,186,272	0.0019	0.9981	98.00
11.5	595,224,223	1,100,062	0.0018	0.9982	97.81
12.5	575,770,776	849,355	0.0015	0.9985	97.63
13.5	547,587,242	884,460	0.0016	0.9984	97.49
14.5	525,277,356	924,206	0.0018	0.9982	97.33
15.5	501,349,891	1,256,773	0.0025	0.9975	97.16
16.5	482,288,665	1,393,443	0.0029	0.9971	96.92
17.5	457,914,644	932,101	0.0020	0.9980	96.64
18.5	445,332,439	898,274	0.0020	0.9980	96.44
19.5	432,863,805	1,107,194	0.0026	0.9974	96.24
20.5	416,001,138	1,494,221	0.0036	0.9964	96.00
21.5	402,278,040	1,167,729	0.0029	0.9971	95.65
22.5	389,649,988	921,619	0.0024	0.9976	95.38
23.5	381,091,842	1,461,546	0.0038	0.9962	95.15
24.5	355,033,774	1,337,891	0.0038	0.9962	94.78
25.5	339,072,213	1,126,668	0.0033	0.9967	94.43
26.5	320,851,175	1,395,418	0.0043	0.9957	94.11
27.5	303,407,985	1,602,517	0.0053	0.9947	93.70
28.5	282,212,221	1,694,239	0.0060	0.9940	93.21
29.5	264,421,647	1,355,842	0.0051	0.9949	92.65
30.5	244,551,697	895,651	0.0037	0.9963	92.17
31.5	227,289,935	785,525	0.0035	0.9965	91.84
32.5	205,301,401	842,704	0.0041	0.9959	91.52
33.5	187,387,157	827,489	0.0044	0.9956	91.14
34.5	170,811,236	813,366	0.0048	0.9952	90.74
35.5	155,529,150	675,301	0.0043	0.9957	90.31
36.5	142,569,349	859,645	0.0060	0.9940	89.92
37.5	130,750,016	454,109	0.0035	0.9965	89.38
38.5	121,532,511	268,902	0.0022	0.9978	89.07

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	112,331,534	326,638	0.0029	0.9971	88.87
40.5	105,138,982	255,057	0.0024	0.9976	88.61
41.5	97,011,264	266,218	0.0027	0.9973	88.39
42.5	90,016,469	219,895	0.0024	0.9976	88.15
43.5	83,476,022	199,705	0.0024	0.9976	87.94
44.5	77,675,720	256,447	0.0033	0.9967	87.73
45.5	73,080,519	122,983	0.0017	0.9983	87.44
46.5	68,610,280	103,249	0.0015	0.9985	87.29
47.5	64,836,681	100,935	0.0016	0.9984	87.16
48.5	60,591,790	166,350	0.0027	0.9973	87.02
49.5	56,199,354	143,020	0.0025	0.9975	86.78
50.5	51,504,941	92,679	0.0018	0.9982	86.56
51.5	47,174,807	128,497	0.0027	0.9973	86.41
52.5	42,756,263	100,388	0.0023	0.9977	86.17
53.5	38,711,530	113,306	0.0029	0.9971	85.97
54.5	34,505,013	98,283	0.0028	0.9972	85.72
55.5	31,381,198	83,720	0.0027	0.9973	85.47
56.5	28,511,765	79,318	0.0028	0.9972	85.25
57.5	25,360,996	67,532	0.0027	0.9973	85.01
58.5	22,378,133	50,218	0.0022	0.9978	84.78
59.5	19,929,563	49,645	0.0025	0.9975	84.59
60.5	17,660,271	48,694	0.0028	0.9972	84.38
61.5	16,506,668	48,246	0.0029	0.9971	84.15
62.5	14,465,706	39,079	0.0027	0.9973	83.90
63.5	12,811,490	36,491	0.0028	0.9972	83.68
64.5	11,115,037	37,124	0.0033	0.9967	83.44
65.5	9,396,832	29,357	0.0031	0.9969	83.16
66.5	7,836,678	22,609	0.0029	0.9971	82.90
67.5	6,442,119	19,709	0.0031	0.9969	82.66
68.5	6,031,815	17,758	0.0029	0.9971	82.41
69.5	4,952,398	30,775	0.0062	0.9938	82.16
70.5	4,075,351	24,176	0.0059	0.9941	81.65
71.5	3,300,363	18,996	0.0058	0.9942	81.17
72.5	2,725,800	8,753	0.0032	0.9968	80.70
73.5	2,180,145	4,620	0.0021	0.9979	80.44
74.5	1,774,197	4,328	0.0024	0.9976	80.27
75.5	1,581,022	2,904	0.0018	0.9982	80.08
76.5	1,388,185	2,423	0.0017	0.9983	79.93
77.5	1,245,111	2,207	0.0018	0.9982	79.79
78.5	1,130,446	1,815	0.0016	0.9984	79.65

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

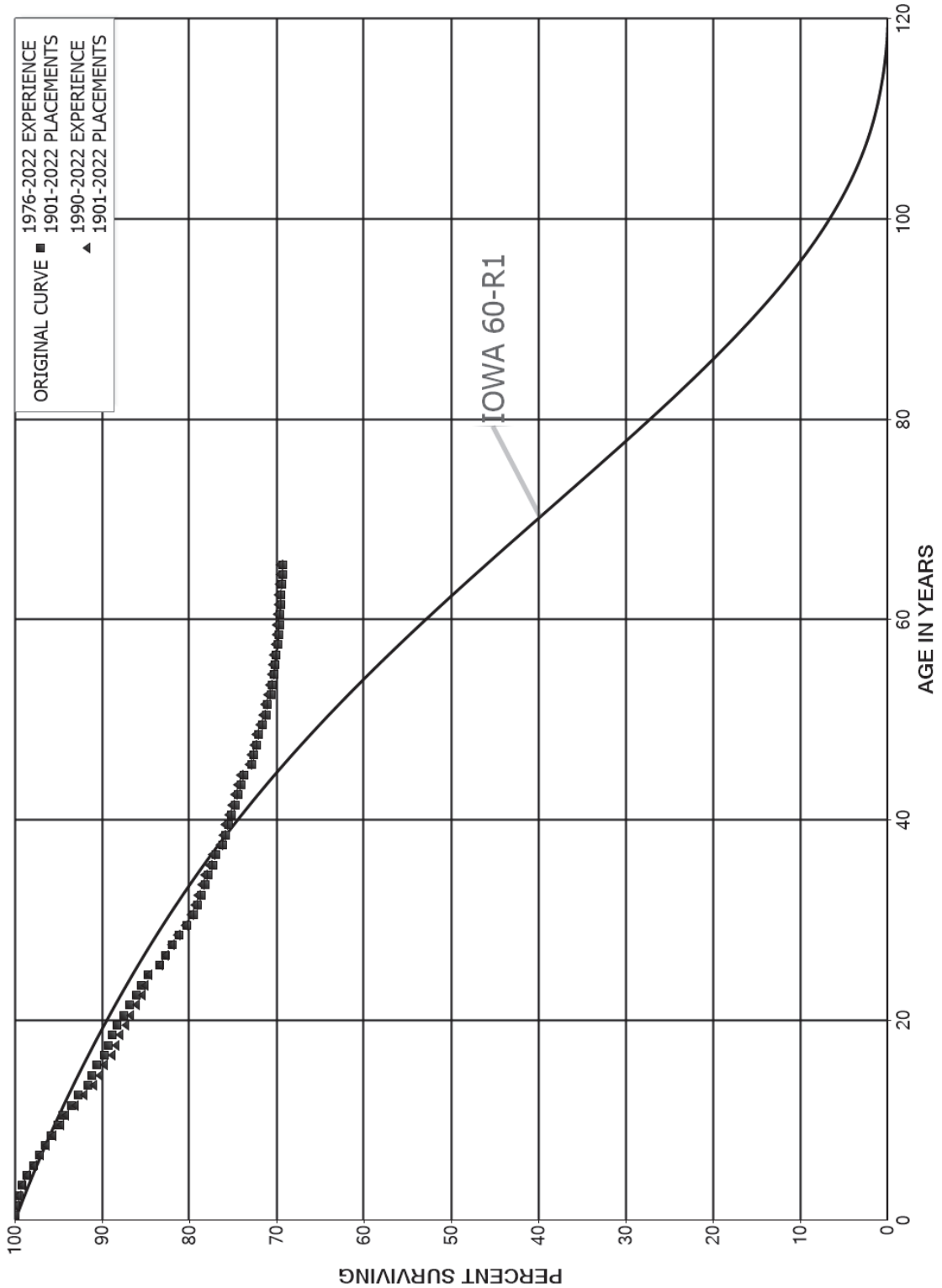
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,002,384	6,388	0.0064	0.9936	79.52
80.5	837,599	2,332	0.0028	0.9972	79.01
81.5	654,689	1,883	0.0029	0.9971	78.79
82.5	506,134	3,271	0.0065	0.9935	78.57
83.5	381,036	444	0.0012	0.9988	78.06
84.5	258,101	134	0.0005	0.9995	77.97
85.5	240,058	144	0.0006	0.9994	77.93
86.5	226,047	334	0.0015	0.9985	77.88
87.5	220,692	432	0.0020	0.9980	77.77
88.5	214,490	581	0.0027	0.9973	77.61
89.5	212,396	319	0.0015	0.9985	77.40
90.5	201,454	288	0.0014	0.9986	77.29
91.5	198,233	388	0.0020	0.9980	77.18
92.5	162,402	216	0.0013	0.9987	77.03
93.5	114,819	144	0.0013	0.9987	76.92
94.5	70,220	8,210	0.1169	0.8831	76.83
95.5	14,147	41	0.0029	0.9971	67.84
96.5	79	79	1.0000		67.65
97.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,801,691,198	730,364	0.0003	0.9997	100.00
0.5	2,654,184,974	5,144,265	0.0019	0.9981	99.97
1.5	2,458,992,177	7,170,673	0.0029	0.9971	99.78
2.5	2,298,090,248	8,102,985	0.0035	0.9965	99.49
3.5	2,130,909,469	11,894,950	0.0056	0.9944	99.14
4.5	1,891,765,706	14,308,825	0.0076	0.9924	98.58
5.5	1,697,037,126	11,706,996	0.0069	0.9931	97.84
6.5	1,530,443,751	9,661,703	0.0063	0.9937	97.16
7.5	1,365,809,899	9,900,723	0.0072	0.9928	96.55
8.5	1,282,008,722	9,809,698	0.0077	0.9923	95.85
9.5	1,167,106,339	7,432,753	0.0064	0.9936	95.12
10.5	1,092,365,929	11,424,395	0.0105	0.9895	94.51
11.5	1,026,404,735	9,033,333	0.0088	0.9912	93.52
12.5	972,842,879	10,959,061	0.0113	0.9887	92.70
13.5	912,583,505	5,307,138	0.0058	0.9942	91.66
14.5	873,171,324	5,088,491	0.0058	0.9942	91.12
15.5	843,034,750	8,030,943	0.0095	0.9905	90.59
16.5	810,553,387	4,459,180	0.0055	0.9945	89.73
17.5	784,121,253	3,868,550	0.0049	0.9951	89.24
18.5	764,060,165	4,593,226	0.0060	0.9940	88.80
19.5	742,044,550	6,469,164	0.0087	0.9913	88.26
20.5	715,890,545	5,381,675	0.0075	0.9925	87.49
21.5	691,294,451	6,306,752	0.0091	0.9909	86.83
22.5	660,656,957	4,544,127	0.0069	0.9931	86.04
23.5	646,474,730	5,234,296	0.0081	0.9919	85.45
24.5	611,301,455	9,595,634	0.0157	0.9843	84.76
25.5	574,272,708	4,594,796	0.0080	0.9920	83.43
26.5	550,503,277	5,245,773	0.0095	0.9905	82.76
27.5	522,128,836	4,962,402	0.0095	0.9905	81.97
28.5	490,726,050	5,287,733	0.0108	0.9892	81.19
29.5	460,485,346	4,656,318	0.0101	0.9899	80.32
30.5	429,061,421	2,581,959	0.0060	0.9940	79.51
31.5	401,846,666	1,891,482	0.0047	0.9953	79.03
32.5	372,272,321	2,092,985	0.0056	0.9944	78.66
33.5	347,268,751	1,626,497	0.0047	0.9953	78.21
34.5	324,544,200	2,273,952	0.0070	0.9930	77.85
35.5	301,597,141	1,228,212	0.0041	0.9959	77.30
36.5	283,960,045	3,127,664	0.0110	0.9890	76.99
37.5	266,357,405	1,194,529	0.0045	0.9955	76.14
38.5	252,878,927	961,774	0.0038	0.9962	75.80

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	239,083,075	1,176,689	0.0049	0.9951	75.51
40.5	231,859,420	1,234,852	0.0053	0.9947	75.14
41.5	218,473,380	868,485	0.0040	0.9960	74.74
42.5	207,225,452	956,388	0.0046	0.9954	74.44
43.5	196,492,924	843,303	0.0043	0.9957	74.10
44.5	187,010,334	2,403,001	0.0128	0.9872	73.78
45.5	176,645,956	648,402	0.0037	0.9963	72.83
46.5	168,466,749	602,257	0.0036	0.9964	72.56
47.5	161,585,027	528,163	0.0033	0.9967	72.30
48.5	150,137,371	885,202	0.0059	0.9941	72.07
49.5	138,041,446	807,100	0.0058	0.9942	71.64
50.5	125,420,509	344,830	0.0027	0.9973	71.22
51.5	117,134,661	595,221	0.0051	0.9949	71.03
52.5	105,268,017	274,270	0.0026	0.9974	70.67
53.5	93,707,409	257,788	0.0028	0.9972	70.48
54.5	81,039,799	178,438	0.0022	0.9978	70.29
55.5	70,426,469	122,376	0.0017	0.9983	70.13
56.5	61,284,395	114,671	0.0019	0.9981	70.01
57.5	50,889,345	78,705	0.0015	0.9985	69.88
58.5	42,120,326	62,176	0.0015	0.9985	69.77
59.5	34,039,163	45,566	0.0013	0.9987	69.67
60.5	27,297,435	24,429	0.0009	0.9991	69.58
61.5	25,736,970	23,402	0.0009	0.9991	69.51
62.5	19,608,666	17,339	0.0009	0.9991	69.45
63.5	16,038,351	16,730	0.0010	0.9990	69.39
64.5	13,470,412	16,070	0.0012	0.9988	69.32
65.5	11,008,946	13,800	0.0013	0.9987	69.23
66.5	8,890,973	11,838	0.0013	0.9987	69.15
67.5	7,145,355	10,377	0.0015	0.9985	69.06
68.5	6,466,387	9,696	0.0015	0.9985	68.96
69.5	5,631,413	13,552	0.0024	0.9976	68.85
70.5	4,727,356	13,106	0.0028	0.9972	68.69
71.5	3,874,725	11,618	0.0030	0.9970	68.50
72.5	3,367,034	7,848	0.0023	0.9977	68.29
73.5	2,759,345	3,993	0.0014	0.9986	68.13
74.5	2,360,592	13,421	0.0057	0.9943	68.03
75.5	2,065,332	9,249	0.0045	0.9955	67.65
76.5	1,884,892	6,942	0.0037	0.9963	67.34
77.5	1,813,916	6,819	0.0038	0.9962	67.10
78.5	1,729,657	7,491	0.0043	0.9957	66.84

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,667,776	5,944	0.0036	0.9964	66.55
80.5	1,536,232	3,733	0.0024	0.9976	66.32
81.5	1,375,855	2,417	0.0018	0.9982	66.16
82.5	1,243,349	31,638	0.0254	0.9746	66.04
83.5	1,106,189	1,433	0.0013	0.9987	64.36
84.5	996,659	2,116	0.0021	0.9979	64.28
85.5	1,689		0.0000	1.0000	64.14
86.5	1,689		0.0000	1.0000	64.14
87.5	1,689		0.0000	1.0000	64.14
88.5	1,689		0.0000	1.0000	64.14
89.5	1,689		0.0000	1.0000	64.14
90.5	1,689		0.0000	1.0000	64.14
91.5	1,689	914	0.5413	0.4587	64.14
92.5	775		0.0000	1.0000	29.42
93.5	775		0.0000	1.0000	29.42
94.5	775		0.0000	1.0000	29.42
95.5	775		0.0000	1.0000	29.42
96.5	775		0.0000	1.0000	29.42
97.5	775		0.0000	1.0000	29.42
98.5	775		0.0000	1.0000	29.42
99.5	775		0.0000	1.0000	29.42
100.5	775		0.0000	1.0000	29.42
101.5	775		0.0000	1.0000	29.42
102.5	775		0.0000	1.0000	29.42
103.5	775		0.0000	1.0000	29.42
104.5	775		0.0000	1.0000	29.42
105.5	775		0.0000	1.0000	29.42
106.5	775		0.0000	1.0000	29.42
107.5	775		0.0000	1.0000	29.42
108.5	775		0.0000	1.0000	29.42
109.5	775		0.0000	1.0000	29.42
110.5	775		0.0000	1.0000	29.42
111.5	775	775	1.0000		29.42
112.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,585,521,391	628,714	0.0002	0.9998	100.00
0.5	2,457,096,769	5,123,588	0.0021	0.9979	99.98
1.5	2,273,832,161	7,095,247	0.0031	0.9969	99.77
2.5	2,114,824,125	8,061,558	0.0038	0.9962	99.46
3.5	1,953,322,771	11,510,710	0.0059	0.9941	99.08
4.5	1,725,746,117	14,168,571	0.0082	0.9918	98.49
5.5	1,534,439,279	11,703,178	0.0076	0.9924	97.68
6.5	1,370,623,771	9,650,158	0.0070	0.9930	96.94
7.5	1,201,758,586	9,879,090	0.0082	0.9918	96.26
8.5	1,119,792,130	9,516,209	0.0085	0.9915	95.47
9.5	1,006,588,233	6,529,238	0.0065	0.9935	94.65
10.5	914,053,871	10,921,221	0.0119	0.9881	94.04
11.5	848,543,998	8,430,190	0.0099	0.9901	92.92
12.5	796,736,402	10,468,574	0.0131	0.9869	91.99
13.5	737,376,953	4,593,699	0.0062	0.9938	90.78
14.5	702,645,702	4,615,381	0.0066	0.9934	90.22
15.5	678,702,282	6,544,177	0.0096	0.9904	89.63
16.5	661,415,792	3,724,495	0.0056	0.9944	88.76
17.5	646,096,367	3,503,532	0.0054	0.9946	88.26
18.5	626,582,817	3,990,658	0.0064	0.9936	87.78
19.5	614,746,282	4,645,253	0.0076	0.9924	87.22
20.5	600,376,946	4,168,423	0.0069	0.9931	86.57
21.5	589,028,918	4,421,996	0.0075	0.9925	85.96
22.5	568,856,091	2,396,822	0.0042	0.9958	85.32
23.5	565,293,113	2,708,873	0.0048	0.9952	84.96
24.5	552,578,505	8,489,741	0.0154	0.9846	84.55
25.5	524,869,940	3,726,858	0.0071	0.9929	83.25
26.5	509,708,879	4,218,590	0.0083	0.9917	82.66
27.5	489,757,910	4,375,937	0.0089	0.9911	81.98
28.5	461,542,392	4,577,548	0.0099	0.9901	81.25
29.5	438,037,276	4,005,292	0.0091	0.9909	80.44
30.5	410,780,945	2,238,562	0.0054	0.9946	79.70
31.5	386,402,069	1,667,303	0.0043	0.9957	79.27
32.5	361,489,218	1,974,236	0.0055	0.9945	78.93
33.5	338,597,652	1,491,400	0.0044	0.9956	78.50
34.5	317,619,557	2,153,177	0.0068	0.9932	78.15
35.5	295,516,699	1,216,020	0.0041	0.9959	77.62
36.5	279,104,144	3,127,664	0.0112	0.9888	77.30
37.5	262,298,854	1,142,521	0.0044	0.9956	76.44
38.5	248,710,744	961,774	0.0039	0.9961	76.10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	235,699,188	1,176,689	0.0050	0.9950	75.81
40.5	229,088,380	1,234,852	0.0054	0.9946	75.43
41.5	216,105,531	868,485	0.0040	0.9960	75.02
42.5	205,146,996	956,388	0.0047	0.9953	74.72
43.5	194,587,699	843,303	0.0043	0.9957	74.37
44.5	185,168,809	2,403,001	0.0130	0.9870	74.05
45.5	174,855,927	648,402	0.0037	0.9963	73.09
46.5	166,733,430	602,257	0.0036	0.9964	72.82
47.5	159,981,182	528,163	0.0033	0.9967	72.56
48.5	148,695,022	885,202	0.0060	0.9940	72.32
49.5	136,738,523	807,100	0.0059	0.9941	71.89
50.5	124,233,067	344,830	0.0028	0.9972	71.46
51.5	116,064,050	595,221	0.0051	0.9949	71.26
52.5	105,225,150	274,270	0.0026	0.9974	70.90
53.5	93,664,543	257,788	0.0028	0.9972	70.71
54.5	80,999,755	178,438	0.0022	0.9978	70.52
55.5	70,389,940	122,376	0.0017	0.9983	70.36
56.5	61,248,383	114,671	0.0019	0.9981	70.24
57.5	50,856,266	78,705	0.0015	0.9985	70.11
58.5	42,090,230	62,176	0.0015	0.9985	70.00
59.5	34,038,249	45,566	0.0013	0.9987	69.90
60.5	27,296,520	24,429	0.0009	0.9991	69.80
61.5	25,736,056	23,402	0.0009	0.9991	69.74
62.5	19,607,751	17,339	0.0009	0.9991	69.68
63.5	16,037,436	16,730	0.0010	0.9990	69.62
64.5	13,469,498	16,070	0.0012	0.9988	69.54
65.5	11,008,031	13,800	0.0013	0.9987	69.46
66.5	8,890,058	11,838	0.0013	0.9987	69.37
67.5	7,144,440	10,377	0.0015	0.9985	69.28
68.5	6,466,387	9,696	0.0015	0.9985	69.18
69.5	5,631,413	13,552	0.0024	0.9976	69.08
70.5	4,727,356	13,106	0.0028	0.9972	68.91
71.5	3,874,725	11,618	0.0030	0.9970	68.72
72.5	3,367,034	7,848	0.0023	0.9977	68.51
73.5	2,759,345	3,993	0.0014	0.9986	68.35
74.5	2,359,817	13,421	0.0057	0.9943	68.26
75.5	2,064,557	9,249	0.0045	0.9955	67.87
76.5	1,884,117	6,942	0.0037	0.9963	67.56
77.5	1,813,141	6,819	0.0038	0.9962	67.31
78.5	1,728,883	7,491	0.0043	0.9957	67.06

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

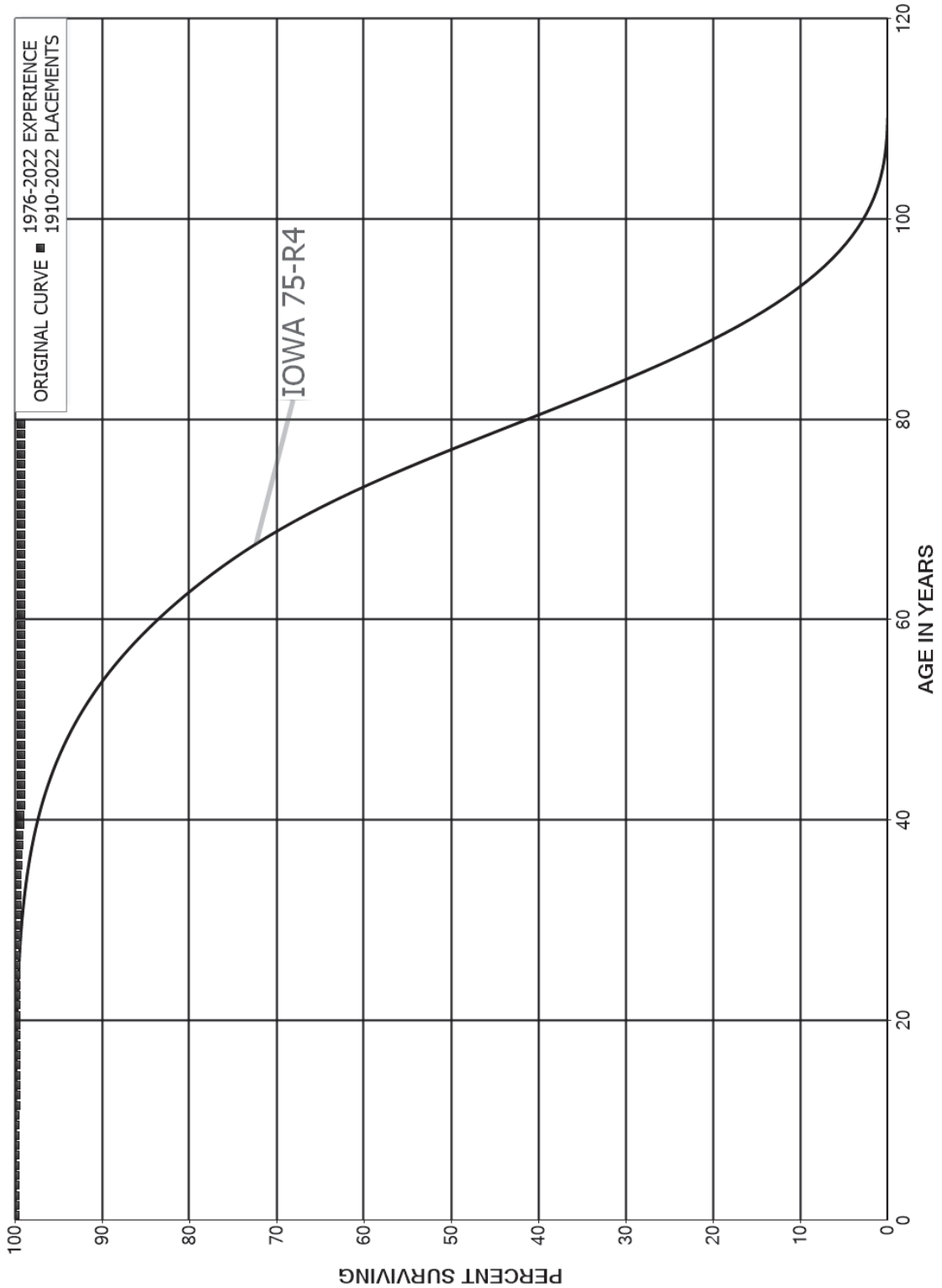
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,667,001	5,944	0.0036	0.9964	66.77
80.5	1,535,457	3,733	0.0024	0.9976	66.53
81.5	1,375,080	2,417	0.0018	0.9982	66.37
82.5	1,242,574	31,638	0.0255	0.9745	66.25
83.5	1,105,414	1,433	0.0013	0.9987	64.57
84.5	995,884	2,116	0.0021	0.9979	64.48
85.5	914		0.0000	1.0000	64.35
86.5	914		0.0000	1.0000	64.35
87.5	914		0.0000	1.0000	64.35
88.5	1,689		0.0000	1.0000	64.35
89.5	1,689		0.0000	1.0000	64.35
90.5	1,689		0.0000	1.0000	64.35
91.5	1,689	914	0.5413	0.4587	64.35
92.5	775		0.0000	1.0000	29.52
93.5	775		0.0000	1.0000	29.52
94.5	775		0.0000	1.0000	29.52
95.5	775		0.0000	1.0000	29.52
96.5	775		0.0000	1.0000	29.52
97.5	775		0.0000	1.0000	29.52
98.5	775		0.0000	1.0000	29.52
99.5	775		0.0000	1.0000	29.52
100.5	775		0.0000	1.0000	29.52
101.5	775		0.0000	1.0000	29.52
102.5	775		0.0000	1.0000	29.52
103.5	775		0.0000	1.0000	29.52
104.5	775		0.0000	1.0000	29.52
105.5	775		0.0000	1.0000	29.52
106.5	775		0.0000	1.0000	29.52
107.5	775		0.0000	1.0000	29.52
108.5	775		0.0000	1.0000	29.52
109.5	775		0.0000	1.0000	29.52
110.5	775		0.0000	1.0000	29.52
111.5	775	775	1.0000		29.52
112.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	424,603,335	6,164	0.0000	1.0000	100.00
0.5	419,917,272	108,833	0.0003	0.9997	100.00
1.5	431,463,616		0.0000	1.0000	99.97
2.5	433,493,583	8,045	0.0000	1.0000	99.97
3.5	419,437,498	55,098	0.0001	0.9999	99.97
4.5	418,256,075	133,735	0.0003	0.9997	99.96
5.5	418,203,691	40,929	0.0001	0.9999	99.93
6.5	420,937,177	21,586	0.0001	0.9999	99.92
7.5	421,518,183	45,881	0.0001	0.9999	99.91
8.5	424,339,325	37,421	0.0001	0.9999	99.90
9.5	413,562,654	1,617	0.0000	1.0000	99.89
10.5	415,873,212	38,524	0.0001	0.9999	99.89
11.5	405,504,578	29,663	0.0001	0.9999	99.88
12.5	395,753,135	14,047	0.0000	1.0000	99.87
13.5	367,676,533	26,902	0.0001	0.9999	99.87
14.5	353,684,706	4,984	0.0000	1.0000	99.86
15.5	342,011,894	4,291	0.0000	1.0000	99.86
16.5	334,606,887	16,627	0.0000	1.0000	99.86
17.5	325,686,764	1,012	0.0000	1.0000	99.86
18.5	320,380,882	14,263	0.0000	1.0000	99.86
19.5	303,634,200	70,060	0.0002	0.9998	99.85
20.5	291,135,341	24,393	0.0001	0.9999	99.83
21.5	288,329,046	3,050	0.0000	1.0000	99.82
22.5	273,719,718	1,225	0.0000	1.0000	99.82
23.5	258,471,941	61,129	0.0002	0.9998	99.82
24.5	234,471,285	10,290	0.0000	1.0000	99.79
25.5	226,925,074	20,482	0.0001	0.9999	99.79
26.5	220,809,153	19,775	0.0001	0.9999	99.78
27.5	206,977,378	38,417	0.0002	0.9998	99.77
28.5	196,809,360	11,743	0.0001	0.9999	99.75
29.5	183,485,646	22,175	0.0001	0.9999	99.75
30.5	170,727,557	20,696	0.0001	0.9999	99.74
31.5	157,986,239	19,804	0.0001	0.9999	99.72
32.5	141,130,502	19,006	0.0001	0.9999	99.71
33.5	126,359,606	23,746	0.0002	0.9998	99.70
34.5	114,150,440	97,266	0.0009	0.9991	99.68
35.5	96,326,486	29,306	0.0003	0.9997	99.59
36.5	92,250,531	46,331	0.0005	0.9995	99.56
37.5	90,240,939	10,037	0.0001	0.9999	99.51
38.5	87,943,866	80,212	0.0009	0.9991	99.50

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	86,112,363	44,389	0.0005	0.9995	99.41
40.5	84,903,753	21,145	0.0002	0.9998	99.36
41.5	80,928,689	15,052	0.0002	0.9998	99.34
42.5	79,509,399	304	0.0000	1.0000	99.32
43.5	76,051,308	1,481	0.0000	1.0000	99.32
44.5	75,286,748	1,828	0.0000	1.0000	99.31
45.5	74,577,706	312	0.0000	1.0000	99.31
46.5	74,408,253	288	0.0000	1.0000	99.31
47.5	73,976,149	265	0.0000	1.0000	99.31
48.5	72,087,210	70	0.0000	1.0000	99.31
49.5	73,181,371	106	0.0000	1.0000	99.31
50.5	70,144,832	95	0.0000	1.0000	99.31
51.5	67,344,436	80	0.0000	1.0000	99.31
52.5	63,982,432	765	0.0000	1.0000	99.31
53.5	60,043,293	58	0.0000	1.0000	99.31
54.5	55,943,946	526	0.0000	1.0000	99.31
55.5	53,046,362	2,329	0.0000	1.0000	99.31
56.5	50,342,475	1,386	0.0000	1.0000	99.30
57.5	47,762,340	84	0.0000	1.0000	99.30
58.5	45,410,393	113	0.0000	1.0000	99.30
59.5	42,600,420	39	0.0000	1.0000	99.30
60.5	39,175,840	30	0.0000	1.0000	99.30
61.5	35,471,591	39	0.0000	1.0000	99.30
62.5	33,696,145	786	0.0000	1.0000	99.30
63.5	32,373,921	1,325	0.0000	1.0000	99.30
64.5	30,913,963	27	0.0000	1.0000	99.29
65.5	28,654,636	36	0.0000	1.0000	99.29
66.5	27,585,142	36	0.0000	1.0000	99.29
67.5	26,028,783	26	0.0000	1.0000	99.29
68.5	24,516,156	13	0.0000	1.0000	99.29
69.5	23,066,327		0.0000	1.0000	99.29
70.5	21,816,265	6	0.0000	1.0000	99.29
71.5	21,083,803		0.0000	1.0000	99.29
72.5	20,603,286	3	0.0000	1.0000	99.29
73.5	20,390,512	6	0.0000	1.0000	99.29
74.5	20,198,544	6	0.0000	1.0000	99.29
75.5	20,001,397	76	0.0000	1.0000	99.29
76.5	19,854,223	6	0.0000	1.0000	99.29
77.5	19,794,670	23	0.0000	1.0000	99.29
78.5	19,771,409	19	0.0000	1.0000	99.29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

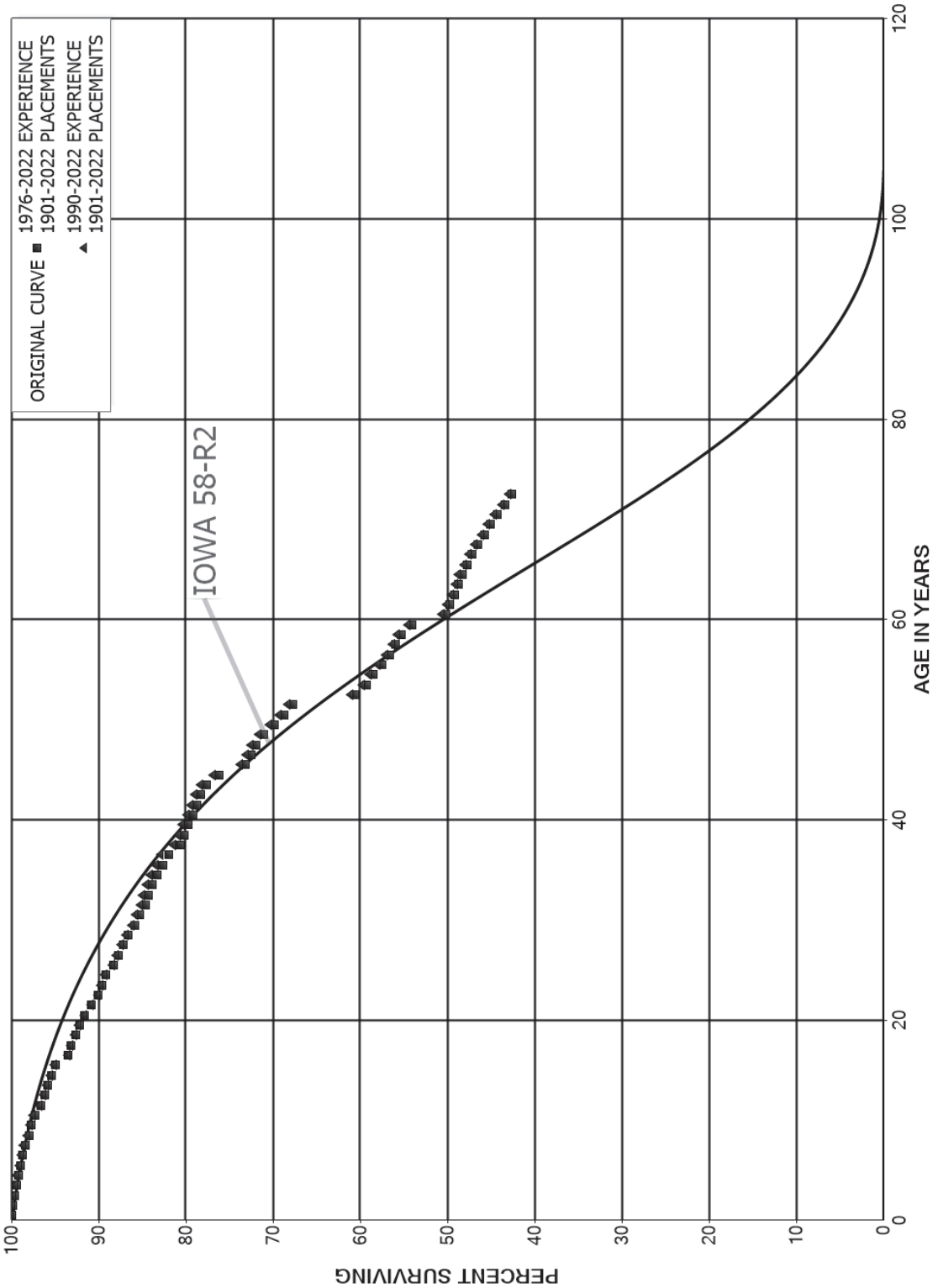
ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	19,658,782	26	0.0000	1.0000	99.29
80.5	19,475,856	78	0.0000	1.0000	99.29
81.5	18,981,765	26	0.0000	1.0000	99.29
82.5	18,300,073	29	0.0000	1.0000	99.29
83.5	17,388,487	38	0.0000	1.0000	99.29
84.5	14,882,586	26	0.0000	1.0000	99.29
85.5	14,314,345	23	0.0000	1.0000	99.29
86.5	13,859,199	23	0.0000	1.0000	99.29
87.5	13,212,408	40	0.0000	1.0000	99.29
88.5	12,720,444	53	0.0000	1.0000	99.29
89.5	12,650,780	62	0.0000	1.0000	99.29
90.5	12,197,330	62	0.0000	1.0000	99.29
91.5	11,128,738	45	0.0000	1.0000	99.29
92.5	9,574,502	152	0.0000	1.0000	99.29
93.5	7,698,469	10	0.0000	1.0000	99.29
94.5	5,915,780	3	0.0000	1.0000	99.29
95.5	4,690,473		0.0000	1.0000	99.29
96.5					99.29

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,513,824,413	1,286,561	0.0008	0.9992	100.00
0.5	1,497,824,649	1,693,667	0.0011	0.9989	99.92
1.5	1,483,417,174	3,509,119	0.0024	0.9976	99.80
2.5	1,472,722,109	2,709,051	0.0018	0.9982	99.57
3.5	1,411,498,554	2,741,375	0.0019	0.9981	99.38
4.5	1,370,893,491	3,599,336	0.0026	0.9974	99.19
5.5	1,327,176,953	3,376,244	0.0025	0.9975	98.93
6.5	1,300,050,137	3,418,021	0.0026	0.9974	98.68
7.5	1,267,855,772	5,612,021	0.0044	0.9956	98.42
8.5	1,251,425,104	3,951,857	0.0032	0.9968	97.98
9.5	1,199,412,846	4,389,340	0.0037	0.9963	97.67
10.5	1,152,091,769	8,737,734	0.0076	0.9924	97.32
11.5	1,101,060,954	4,246,399	0.0039	0.9961	96.58
12.5	1,065,157,744	4,343,312	0.0041	0.9959	96.21
13.5	868,349,903	4,002,317	0.0046	0.9954	95.81
14.5	819,518,282	3,182,515	0.0039	0.9961	95.37
15.5	774,573,181	12,448,067	0.0161	0.9839	95.00
16.5	723,614,659	2,716,954	0.0038	0.9962	93.47
17.5	686,842,637	3,425,274	0.0050	0.9950	93.12
18.5	659,012,069	3,476,463	0.0053	0.9947	92.66
19.5	621,686,577	3,893,981	0.0063	0.9937	92.17
20.5	586,062,291	5,157,488	0.0088	0.9912	91.59
21.5	548,465,027	4,447,676	0.0081	0.9919	90.79
22.5	514,438,654	2,560,874	0.0050	0.9950	90.05
23.5	492,228,196	2,593,763	0.0053	0.9947	89.60
24.5	444,714,662	4,465,703	0.0100	0.9900	89.13
25.5	415,612,194	2,268,861	0.0055	0.9945	88.24
26.5	388,257,188	2,365,590	0.0061	0.9939	87.75
27.5	363,988,659	2,478,781	0.0068	0.9932	87.22
28.5	336,195,279	2,922,474	0.0087	0.9913	86.62
29.5	304,070,281	2,244,536	0.0074	0.9926	85.87
30.5	279,264,517	1,979,499	0.0071	0.9929	85.24
31.5	252,447,712	943,940	0.0037	0.9963	84.63
32.5	239,293,527	1,311,277	0.0055	0.9945	84.32
33.5	214,453,071	1,423,453	0.0066	0.9934	83.86
34.5	195,728,347	1,635,031	0.0084	0.9916	83.30
35.5	172,154,201	1,289,935	0.0075	0.9925	82.60
36.5	158,347,699	2,569,900	0.0162	0.9838	81.98
37.5	144,172,161	880,902	0.0061	0.9939	80.65
38.5	133,444,535	755,090	0.0057	0.9943	80.16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	125,350,965	857,938	0.0068	0.9932	79.71
40.5	124,464,016	680,204	0.0055	0.9945	79.16
41.5	116,861,035	685,787	0.0059	0.9941	78.73
42.5	109,931,965	914,078	0.0083	0.9917	78.27
43.5	101,600,495	1,849,883	0.0182	0.9818	77.62
44.5	94,067,346	3,743,567	0.0398	0.9602	76.20
45.5	86,317,554	739,655	0.0086	0.9914	73.17
46.5	80,089,501	665,457	0.0083	0.9917	72.54
47.5	73,533,360	891,478	0.0121	0.9879	71.94
48.5	67,616,087	1,121,779	0.0166	0.9834	71.07
49.5	60,204,886	1,017,015	0.0169	0.9831	69.89
50.5	53,000,685	744,843	0.0141	0.9859	68.71
51.5	52,255,842	5,473,873	0.1048	0.8952	67.74
52.5	40,854,111	922,296	0.0226	0.9774	60.65
53.5	33,887,822	435,474	0.0129	0.9871	59.28
54.5	28,762,547	495,903	0.0172	0.9828	58.52
55.5	24,347,512	360,101	0.0148	0.9852	57.51
56.5	20,766,287	275,867	0.0133	0.9867	56.66
57.5	18,274,250	188,115	0.0103	0.9897	55.90
58.5	15,256,705	339,709	0.0223	0.9777	55.33
59.5	12,471,219	893,433	0.0716	0.9284	54.10
60.5	11,233,848	111,545	0.0099	0.9901	50.22
61.5	11,122,303	117,899	0.0106	0.9894	49.72
62.5	8,897,746	82,917	0.0093	0.9907	49.20
63.5	7,426,839	63,381	0.0085	0.9915	48.74
64.5	5,971,254	71,455	0.0120	0.9880	48.32
65.5	4,686,506	56,652	0.0121	0.9879	47.74
66.5	3,467,082	46,739	0.0135	0.9865	47.17
67.5	2,166,713	35,432	0.0164	0.9836	46.53
68.5	2,131,282	32,523	0.0153	0.9847	45.77
69.5	2,098,759	37,127	0.0177	0.9823	45.07
70.5	1,590,334	30,217	0.0190	0.9810	44.27
71.5	1,149,949	21,708	0.0189	0.9811	43.43
72.5	906,796	17,335	0.0191	0.9809	42.61
73.5	640,671	15,755	0.0246	0.9754	41.80
74.5	410,506	6,673	0.0163	0.9837	40.77
75.5	395,251	9,817	0.0248	0.9752	40.11
76.5	325,090	6,323	0.0194	0.9806	39.11
77.5	277,753	3,588	0.0129	0.9871	38.35
78.5	253,338	2,716	0.0107	0.9893	37.85

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	230,170	2,079	0.0090	0.9910	37.45
80.5	180,592	6,645	0.0368	0.9632	37.11
81.5	100,078	1,062	0.0106	0.9894	35.74
82.5	38,433	220	0.0057	0.9943	35.37
83.5	26,531	180	0.0068	0.9932	35.16
84.5	24,316	195	0.0080	0.9920	34.92
85.5	24,121	32	0.0013	0.9987	34.64
86.5	24,089		0.0000	1.0000	34.60
87.5	24,089		0.0000	1.0000	34.60
88.5	24,089		0.0000	1.0000	34.60
89.5	24,089		0.0000	1.0000	34.60
90.5	24,089	203	0.0084	0.9916	34.60
91.5	23,886	562	0.0235	0.9765	34.31
92.5	23,323	415	0.0178	0.9822	33.50
93.5	22,908		0.0000	1.0000	32.90
94.5	22,908	19,009	0.8298	0.1702	32.90
95.5	3,899		0.0000	1.0000	5.60
96.5	3,899	3,899	1.0000		5.60
97.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,349,144,662	846,675	0.0006	0.9994	100.00
0.5	1,352,465,702	1,322,793	0.0010	0.9990	99.94
1.5	1,351,276,628	2,051,781	0.0015	0.9985	99.84
2.5	1,353,422,844	1,802,869	0.0013	0.9987	99.69
3.5	1,299,458,357	2,294,371	0.0018	0.9982	99.56
4.5	1,278,341,673	3,457,544	0.0027	0.9973	99.38
5.5	1,237,868,495	3,370,655	0.0027	0.9973	99.11
6.5	1,211,625,661	3,304,433	0.0027	0.9973	98.84
7.5	1,176,484,963	5,003,972	0.0043	0.9957	98.57
8.5	1,162,230,513	3,677,069	0.0032	0.9968	98.15
9.5	1,112,145,772	3,872,432	0.0035	0.9965	97.84
10.5	1,063,006,733	8,514,019	0.0080	0.9920	97.50
11.5	1,014,741,242	4,034,245	0.0040	0.9960	96.72
12.5	980,822,013	4,123,691	0.0042	0.9958	96.34
13.5	788,807,212	3,865,349	0.0049	0.9951	95.93
14.5	746,328,764	2,795,811	0.0037	0.9963	95.46
15.5	704,577,174	11,745,465	0.0167	0.9833	95.10
16.5	662,308,194	2,496,598	0.0038	0.9962	93.52
17.5	630,928,975	3,007,093	0.0048	0.9952	93.16
18.5	597,650,428	3,089,223	0.0052	0.9948	92.72
19.5	566,712,873	3,717,252	0.0066	0.9934	92.24
20.5	536,764,196	4,840,088	0.0090	0.9910	91.64
21.5	504,380,968	3,934,515	0.0078	0.9922	90.81
22.5	473,173,909	2,072,501	0.0044	0.9956	90.10
23.5	455,756,358	2,038,304	0.0045	0.9955	89.71
24.5	417,376,250	4,294,455	0.0103	0.9897	89.31
25.5	385,446,999	2,055,301	0.0053	0.9947	88.39
26.5	360,956,289	2,092,769	0.0058	0.9942	87.92
27.5	338,055,917	2,121,011	0.0063	0.9937	87.41
28.5	310,770,313	2,425,526	0.0078	0.9922	86.86
29.5	281,432,369	1,608,380	0.0057	0.9943	86.18
30.5	258,740,902	1,550,835	0.0060	0.9940	85.69
31.5	233,885,240	598,096	0.0026	0.9974	85.17
32.5	225,533,029	1,095,838	0.0049	0.9951	84.96
33.5	202,142,511	1,191,882	0.0059	0.9941	84.54
34.5	185,262,589	1,443,047	0.0078	0.9922	84.04
35.5	162,534,273	1,165,465	0.0072	0.9928	83.39
36.5	149,624,006	2,569,900	0.0172	0.9828	82.79
37.5	136,026,796	880,902	0.0065	0.9935	81.37
38.5	125,926,312	755,090	0.0060	0.9940	80.84

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	124,266,142	857,938	0.0069	0.9931	80.36
40.5	123,689,406	680,204	0.0055	0.9945	79.80
41.5	116,382,564	685,787	0.0059	0.9941	79.36
42.5	109,466,075	914,078	0.0084	0.9916	78.90
43.5	101,210,074	1,849,883	0.0183	0.9817	78.24
44.5	93,730,197	3,743,567	0.0399	0.9601	76.81
45.5	86,007,405	739,655	0.0086	0.9914	73.74
46.5	79,806,022	665,457	0.0083	0.9917	73.11
47.5	73,307,312	891,478	0.0122	0.9878	72.50
48.5	67,484,858	1,121,779	0.0166	0.9834	71.61
49.5	60,161,931	1,017,015	0.0169	0.9831	70.42
50.5	52,973,277	744,843	0.0141	0.9859	69.23
51.5	52,233,939	5,473,873	0.1048	0.8952	68.26
52.5	40,833,323	922,296	0.0226	0.9774	61.11
53.5	33,867,171	435,474	0.0129	0.9871	59.73
54.5	28,741,878	495,903	0.0173	0.9827	58.96
55.5	24,326,585	360,101	0.0148	0.9852	57.94
56.5	20,745,474	275,867	0.0133	0.9867	57.08
57.5	18,258,337	188,115	0.0103	0.9897	56.32
58.5	15,241,712	339,709	0.0223	0.9777	55.74
59.5	12,455,844	893,433	0.0717	0.9283	54.50
60.5	11,218,906	111,545	0.0099	0.9901	50.59
61.5	11,116,811	117,899	0.0106	0.9894	50.09
62.5	8,892,443	82,917	0.0093	0.9907	49.56
63.5	7,424,689	63,381	0.0085	0.9915	49.10
64.5	5,969,332	71,455	0.0120	0.9880	48.68
65.5	4,684,583	56,652	0.0121	0.9879	48.09
66.5	3,465,159	46,739	0.0135	0.9865	47.51
67.5	2,164,994	35,432	0.0164	0.9836	46.87
68.5	2,129,872	32,523	0.0153	0.9847	46.11
69.5	2,097,764	37,127	0.0177	0.9823	45.40
70.5	1,589,339	30,217	0.0190	0.9810	44.60
71.5	1,148,806	21,708	0.0189	0.9811	43.75
72.5	905,653	17,335	0.0191	0.9809	42.92
73.5	640,418	15,755	0.0246	0.9754	42.10
74.5	388,340	6,673	0.0172	0.9828	41.07
75.5	373,084	9,817	0.0263	0.9737	40.36
76.5	302,923	6,323	0.0209	0.9791	39.30
77.5	255,587	3,588	0.0140	0.9860	38.48
78.5	231,172	2,716	0.0117	0.9883	37.94

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

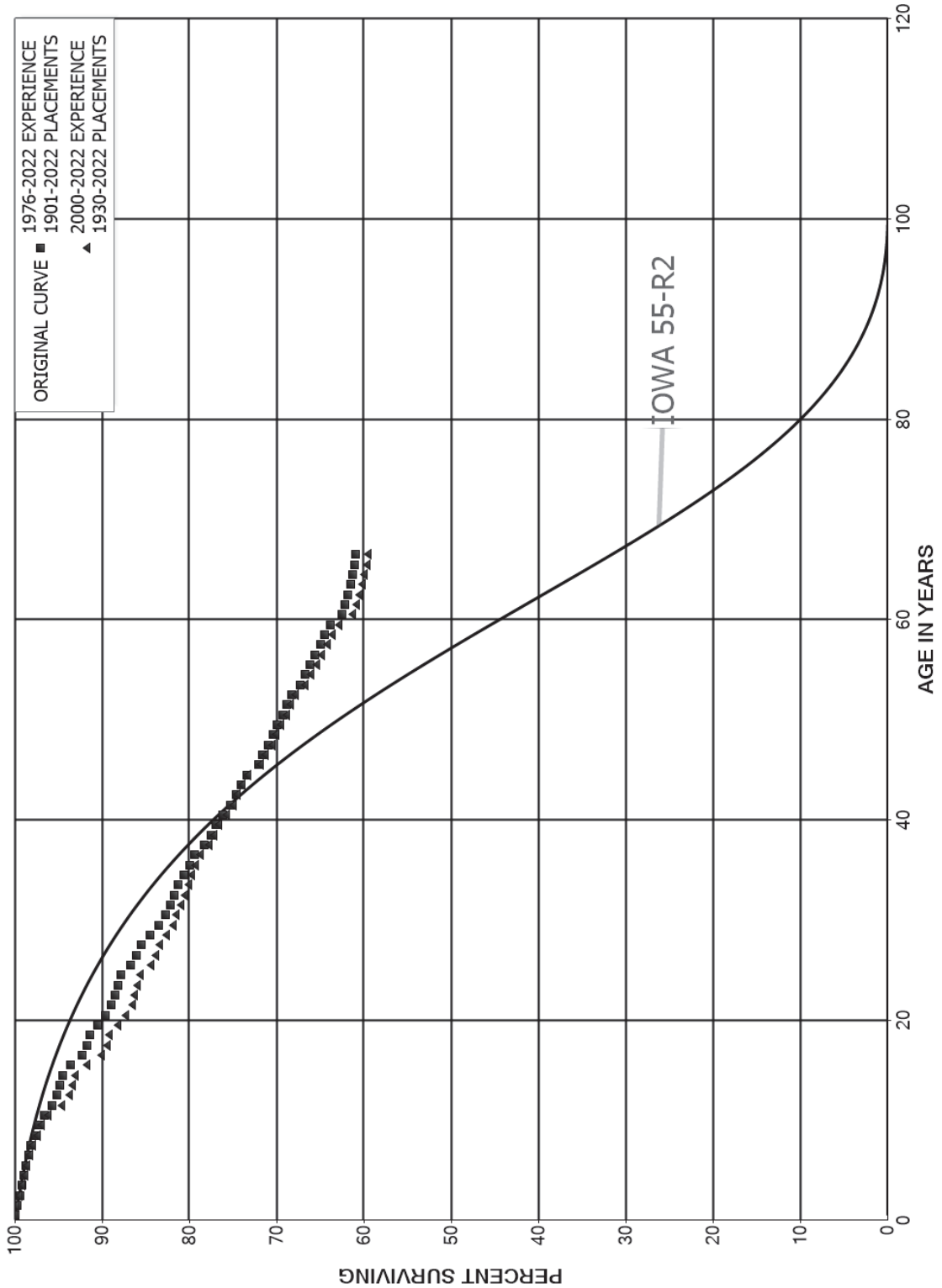
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	208,004	2,079	0.0100	0.9900	37.49
80.5	158,426	6,645	0.0419	0.9581	37.12
81.5	77,912	1,062	0.0136	0.9864	35.56
82.5	16,266	220	0.0135	0.9865	35.08
83.5	4,365	180	0.0413	0.9587	34.60
84.5	2,150	195	0.0907	0.9093	33.17
85.5	2,208	32	0.0145	0.9855	30.16
86.5	2,176		0.0000	1.0000	29.72
87.5	2,176		0.0000	1.0000	29.72
88.5	24,089		0.0000	1.0000	29.72
89.5	24,089		0.0000	1.0000	29.72
90.5	24,089	203	0.0084	0.9916	29.72
91.5	23,886	562	0.0235	0.9765	29.47
92.5	23,323	415	0.0178	0.9822	28.78
93.5	22,908		0.0000	1.0000	28.27
94.5	22,908	19,009	0.8298	0.1702	28.27
95.5	3,899		0.0000	1.0000	4.81
96.5	3,899	3,899	1.0000		4.81
97.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 368.00 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,558,173,709	1,138,160	0.0007	0.9993	100.00
0.5	1,470,475,556	2,415,422	0.0016	0.9984	99.93
1.5	1,422,126,043	5,251,391	0.0037	0.9963	99.76
2.5	1,371,036,498	3,348,098	0.0024	0.9976	99.39
3.5	1,303,083,985	3,104,495	0.0024	0.9976	99.15
4.5	1,248,092,594	2,608,525	0.0021	0.9979	98.92
5.5	1,186,658,722	3,150,976	0.0027	0.9973	98.71
6.5	1,136,654,568	3,534,506	0.0031	0.9969	98.45
7.5	1,087,261,829	5,268,311	0.0048	0.9952	98.14
8.5	1,053,323,253	4,491,823	0.0043	0.9957	97.66
9.5	1,009,388,226	6,118,801	0.0061	0.9939	97.25
10.5	995,241,217	9,393,558	0.0094	0.9906	96.66
11.5	981,275,802	6,145,629	0.0063	0.9937	95.75
12.5	975,946,794	3,048,575	0.0031	0.9969	95.15
13.5	941,294,861	3,532,684	0.0038	0.9962	94.85
14.5	928,962,968	8,918,625	0.0096	0.9904	94.49
15.5	912,079,533	12,552,062	0.0138	0.9862	93.59
16.5	882,543,541	4,971,237	0.0056	0.9944	92.30
17.5	863,242,127	3,945,596	0.0046	0.9954	91.78
18.5	856,702,965	7,968,972	0.0093	0.9907	91.36
19.5	842,641,593	8,024,731	0.0095	0.9905	90.51
20.5	804,917,459	6,609,505	0.0082	0.9918	89.65
21.5	780,332,662	3,236,986	0.0041	0.9959	88.91
22.5	770,161,048	3,069,485	0.0040	0.9960	88.54
23.5	755,681,703	3,509,876	0.0046	0.9954	88.19
24.5	730,989,749	9,201,442	0.0126	0.9874	87.78
25.5	701,470,195	4,940,783	0.0070	0.9930	86.68
26.5	672,364,811	4,776,476	0.0071	0.9929	86.06
27.5	652,232,327	7,574,542	0.0116	0.9884	85.45
28.5	633,959,314	7,078,919	0.0112	0.9888	84.46
29.5	608,324,260	5,769,439	0.0095	0.9905	83.52
30.5	586,710,867	4,198,360	0.0072	0.9928	82.73
31.5	572,863,805	2,804,833	0.0049	0.9951	82.13
32.5	558,346,145	3,235,238	0.0058	0.9942	81.73
33.5	520,993,713	3,820,220	0.0073	0.9927	81.26
34.5	481,802,228	4,015,663	0.0083	0.9917	80.66
35.5	437,054,082	3,222,490	0.0074	0.9926	79.99
36.5	393,558,106	5,544,259	0.0141	0.9859	79.40
37.5	358,797,339	3,360,523	0.0094	0.9906	78.28
38.5	321,869,923	2,617,374	0.0081	0.9919	77.55

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	302,603,694	3,077,413	0.0102	0.9898	76.92
40.5	290,083,333	3,219,753	0.0111	0.9889	76.14
41.5	271,538,015	2,417,304	0.0089	0.9911	75.29
42.5	252,100,810	1,815,001	0.0072	0.9928	74.62
43.5	236,770,762	2,137,249	0.0090	0.9910	74.08
44.5	220,046,825	3,930,379	0.0179	0.9821	73.41
45.5	209,197,933	1,448,758	0.0069	0.9931	72.10
46.5	199,882,622	1,950,956	0.0098	0.9902	71.60
47.5	186,766,785	1,272,055	0.0068	0.9932	70.90
48.5	172,906,336	1,263,569	0.0073	0.9927	70.42
49.5	157,183,608	1,361,733	0.0087	0.9913	69.91
50.5	141,127,177	938,442	0.0066	0.9934	69.30
51.5	126,749,267	963,567	0.0076	0.9924	68.84
52.5	119,990,611	1,736,134	0.0145	0.9855	68.32
53.5	112,287,423	1,064,658	0.0095	0.9905	67.33
54.5	105,141,480	889,853	0.0085	0.9915	66.69
55.5	95,461,699	786,425	0.0082	0.9918	66.13
56.5	89,004,321	788,905	0.0089	0.9911	65.58
57.5	82,184,237	643,365	0.0078	0.9922	65.00
58.5	70,065,268	683,317	0.0098	0.9902	64.49
59.5	56,296,789	1,220,033	0.0217	0.9783	63.86
60.5	46,999,687	243,195	0.0052	0.9948	62.48
61.5	40,357,487	212,640	0.0053	0.9947	62.15
62.5	33,862,606	177,131	0.0052	0.9948	61.83
63.5	30,610,761	112,055	0.0037	0.9963	61.50
64.5	25,514,612	103,322	0.0040	0.9960	61.28
65.5	21,425,079	48,364	0.0023	0.9977	61.03
66.5	14,568,670	11,325	0.0008	0.9992	60.89
67.5	13,853,800	11,333	0.0008	0.9992	60.85
68.5	12,835,953	13,247	0.0010	0.9990	60.80
69.5	11,880,359	1,353	0.0001	0.9999	60.73
70.5	11,641,438	1,122	0.0001	0.9999	60.73
71.5	11,454,977	9,305	0.0008	0.9992	60.72
72.5	11,146,520	32,361	0.0029	0.9971	60.67
73.5	10,785,738	117,713	0.0109	0.9891	60.49
74.5	10,595,095	149,152	0.0141	0.9859	59.83
75.5	10,362,088	222,823	0.0215	0.9785	58.99
76.5	10,008,649	238,772	0.0239	0.9761	57.72
77.5	9,633,477	235,814	0.0245	0.9755	56.35
78.5	9,198,702	239,803	0.0261	0.9739	54.97

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,886,438	214,592	0.0241	0.9759	53.53
80.5	8,047,107	199,910	0.0248	0.9752	52.24
81.5	7,768,918	183,944	0.0237	0.9763	50.94
82.5	7,553,994	164,032	0.0217	0.9783	49.74
83.5	6,439,216	133,642	0.0208	0.9792	48.66
84.5	4,776,679	73,186	0.0153	0.9847	47.65
85.5	3,216,563	48,512	0.0151	0.9849	46.92
86.5	1,981,550	21,973	0.0111	0.9889	46.21
87.5	1,703,087	33,168	0.0195	0.9805	45.70
88.5	1,344,268	21,104	0.0157	0.9843	44.81
89.5	956,254	14,386	0.0150	0.9850	44.10
90.5	663,366	10,645	0.0160	0.9840	43.44
91.5	371,063	9,209	0.0248	0.9752	42.74
92.5	20,380	15,365	0.7539	0.2461	41.68
93.5	5,015	1,430	0.2852	0.7148	10.26
94.5	3,585	2,865	0.7992	0.2008	7.33
95.5	720	360	0.5000	0.5000	1.47
96.5	360	360	1.0000		0.74
97.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1930-2022 EXPERIENCE BAND 2000-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	946,506,717	551,823	0.0006	0.9994	100.00
0.5	873,836,489	1,693,926	0.0019	0.9981	99.94
1.5	835,076,922	3,112,502	0.0037	0.9963	99.75
2.5	781,379,217	2,411,632	0.0031	0.9969	99.38
3.5	724,795,928	2,374,591	0.0033	0.9967	99.07
4.5	675,704,784	1,806,967	0.0027	0.9973	98.74
5.5	637,923,140	2,057,787	0.0032	0.9968	98.48
6.5	602,239,322	2,118,494	0.0035	0.9965	98.16
7.5	569,416,603	3,282,308	0.0058	0.9942	97.82
8.5	539,036,297	2,464,218	0.0046	0.9954	97.25
9.5	502,871,275	3,587,640	0.0071	0.9929	96.81
10.5	494,200,112	8,261,654	0.0167	0.9833	96.12
11.5	503,366,348	4,858,613	0.0097	0.9903	94.51
12.5	527,637,511	1,939,885	0.0037	0.9963	93.60
13.5	530,275,464	1,778,839	0.0034	0.9966	93.26
14.5	560,569,444	7,957,939	0.0142	0.9858	92.94
15.5	574,683,664	10,771,876	0.0187	0.9813	91.62
16.5	564,805,556	3,630,892	0.0064	0.9936	89.91
17.5	554,622,680	1,959,726	0.0035	0.9965	89.33
18.5	551,153,853	5,973,533	0.0108	0.9892	89.01
19.5	550,839,346	5,735,626	0.0104	0.9896	88.05
20.5	534,104,959	4,230,756	0.0079	0.9921	87.13
21.5	526,409,116	1,951,981	0.0037	0.9963	86.44
22.5	519,816,156	1,693,121	0.0033	0.9967	86.12
23.5	514,894,750	2,149,000	0.0042	0.9958	85.84
24.5	503,497,815	7,340,274	0.0146	0.9854	85.48
25.5	487,929,100	2,807,341	0.0058	0.9942	84.24
26.5	481,970,928	2,607,606	0.0054	0.9946	83.75
27.5	480,478,103	4,666,008	0.0097	0.9903	83.30
28.5	480,907,917	4,164,500	0.0087	0.9913	82.49
29.5	464,639,264	2,408,362	0.0052	0.9948	81.77
30.5	452,842,821	3,166,327	0.0070	0.9930	81.35
31.5	446,572,743	2,376,821	0.0053	0.9947	80.78
32.5	442,531,482	2,060,517	0.0047	0.9953	80.35
33.5	411,548,916	1,862,533	0.0045	0.9955	79.98
34.5	390,431,835	2,398,577	0.0061	0.9939	79.62
35.5	362,488,878	2,197,349	0.0061	0.9939	79.13
36.5	333,564,552	4,461,862	0.0134	0.9866	78.65
37.5	306,383,447	2,150,312	0.0070	0.9930	77.59
38.5	275,557,774	2,018,465	0.0073	0.9927	77.05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2022 EXPERIENCE BAND 2000-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	262,891,991	2,862,310	0.0109	0.9891	76.49
40.5	253,892,377	2,617,112	0.0103	0.9897	75.65
41.5	240,878,281	1,687,172	0.0070	0.9930	74.87
42.5	229,454,850	1,716,329	0.0075	0.9925	74.35
43.5	220,972,672	2,003,200	0.0091	0.9909	73.79
44.5	204,784,816	3,913,744	0.0191	0.9809	73.12
45.5	194,671,416	1,444,186	0.0074	0.9926	71.73
46.5	186,356,254	1,947,814	0.0105	0.9895	71.19
47.5	173,481,244	1,270,625	0.0073	0.9927	70.45
48.5	159,814,927	1,235,603	0.0077	0.9923	69.93
49.5	146,023,412	1,359,061	0.0093	0.9907	69.39
50.5	130,301,372	938,442	0.0072	0.9928	68.75
51.5	115,997,959	963,567	0.0083	0.9917	68.25
52.5	109,327,166	1,735,588	0.0159	0.9841	67.69
53.5	101,756,290	1,064,658	0.0105	0.9895	66.61
54.5	94,748,724	887,150	0.0094	0.9906	65.91
55.5	85,300,950	784,622	0.0092	0.9908	65.30
56.5	78,917,853	787,624	0.0100	0.9900	64.70
57.5	72,848,610	643,083	0.0088	0.9912	64.05
58.5	60,808,201	682,819	0.0112	0.9888	63.48
59.5	47,077,130	1,218,272	0.0259	0.9741	62.77
60.5	39,182,678	241,794	0.0062	0.9938	61.15
61.5	34,706,666	212,460	0.0061	0.9939	60.77
62.5	30,159,045	177,131	0.0059	0.9941	60.40
63.5	28,450,291	112,055	0.0039	0.9961	60.04
64.5	23,627,697	103,268	0.0044	0.9956	59.81
65.5	19,910,104	48,364	0.0024	0.9976	59.55
66.5	13,496,366	11,325	0.0008	0.9992	59.40
67.5	13,085,815	10,049	0.0008	0.9992	59.35
68.5	12,428,046	12,929	0.0010	0.9990	59.31
69.5	11,878,051	753	0.0001	0.9999	59.24
70.5	11,639,401	1,025	0.0001	0.9999	59.24
71.5	11,453,038	8,807	0.0008	0.9992	59.23
72.5	11,127,928	32,361	0.0029	0.9971	59.19
73.5	10,765,356	117,615	0.0109	0.9891	59.02
74.5	10,573,370	149,025	0.0141	0.9859	58.37
75.5	10,340,490	222,823	0.0215	0.9785	57.55
76.5	9,987,051	238,772	0.0239	0.9761	56.31
77.5	9,611,879	235,814	0.0245	0.9755	54.96
78.5	9,177,103	239,803	0.0261	0.9739	53.61

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

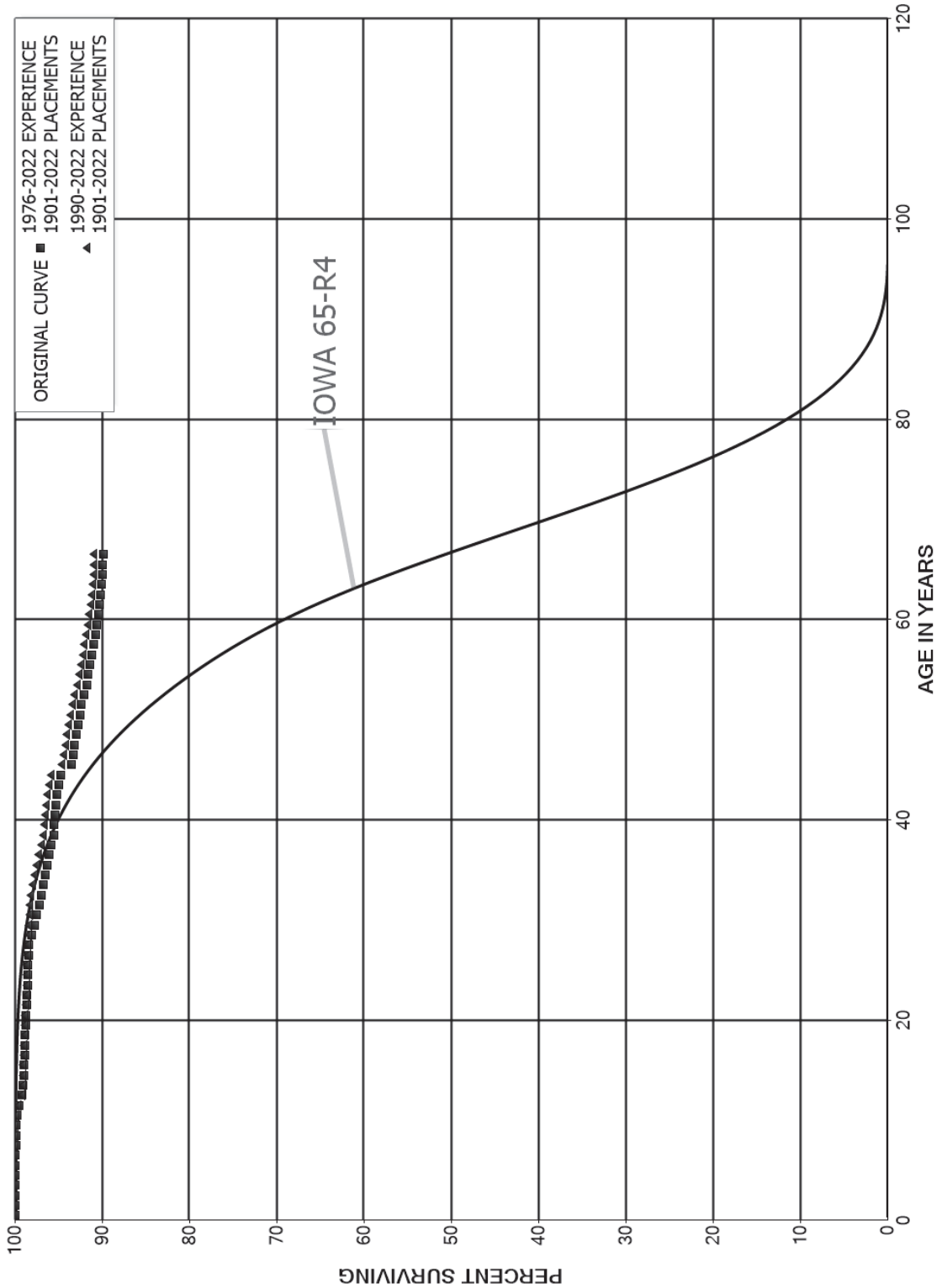
ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2022 EXPERIENCE BAND 2000-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,864,840	214,592	0.0242	0.9758	52.21
80.5	8,025,508	199,910	0.0249	0.9751	50.95
81.5	7,747,319	183,865	0.0237	0.9763	49.68
82.5	7,532,474	164,032	0.0218	0.9782	48.50
83.5	6,417,696	133,642	0.0208	0.9792	47.45
84.5	4,755,159	73,186	0.0154	0.9846	46.46
85.5	3,195,043	48,512	0.0152	0.9848	45.74
86.5	1,960,030	21,162	0.0108	0.9892	45.05
87.5	1,682,378	33,168	0.0197	0.9803	44.56
88.5	1,323,559	21,104	0.0159	0.9841	43.68
89.5	935,546	14,386	0.0154	0.9846	42.99
90.5	642,658	10,317	0.0161	0.9839	42.33
91.5	350,683	9,209	0.0263	0.9737	41.65
92.5					40.55

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 369.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	544,181,811	18,817	0.0000	1.0000	100.00
0.5	515,227,917	35,465	0.0001	0.9999	100.00
1.5	517,063,572	88,125	0.0002	0.9998	99.99
2.5	501,488,293	46,937	0.0001	0.9999	99.97
3.5	487,306,080	88,475	0.0002	0.9998	99.96
4.5	471,340,281	128,995	0.0003	0.9997	99.95
5.5	468,984,050	85,127	0.0002	0.9998	99.92
6.5	465,417,444	154,374	0.0003	0.9997	99.90
7.5	463,825,326	148,421	0.0003	0.9997	99.87
8.5	462,557,292	199,011	0.0004	0.9996	99.83
9.5	463,323,719	175,229	0.0004	0.9996	99.79
10.5	456,037,049	1,362,094	0.0030	0.9970	99.75
11.5	441,537,500	1,406,589	0.0032	0.9968	99.46
12.5	423,393,358	541,087	0.0013	0.9987	99.14
13.5	408,180,351	151,288	0.0004	0.9996	99.01
14.5	391,342,243	138,881	0.0004	0.9996	98.98
15.5	372,765,422	257,482	0.0007	0.9993	98.94
16.5	353,670,750	133,428	0.0004	0.9996	98.87
17.5	336,120,416	122,302	0.0004	0.9996	98.83
18.5	316,708,598	103,606	0.0003	0.9997	98.80
19.5	297,086,477	155,127	0.0005	0.9995	98.77
20.5	284,266,300	253,390	0.0009	0.9991	98.72
21.5	270,106,748	147,017	0.0005	0.9995	98.63
22.5	256,101,622	73,489	0.0003	0.9997	98.57
23.5	244,324,219	75,715	0.0003	0.9997	98.55
24.5	229,893,270	117,551	0.0005	0.9995	98.51
25.5	217,697,958	78,208	0.0004	0.9996	98.46
26.5	202,538,147	74,020	0.0004	0.9996	98.43
27.5	188,687,008	700,074	0.0037	0.9963	98.39
28.5	174,587,474	479,080	0.0027	0.9973	98.03
29.5	162,282,354	507,943	0.0031	0.9969	97.76
30.5	152,533,476	353,088	0.0023	0.9977	97.45
31.5	143,797,692	336,976	0.0023	0.9977	97.23
32.5	134,549,470	317,705	0.0024	0.9976	97.00
33.5	125,083,916	280,182	0.0022	0.9978	96.77
34.5	115,318,546	290,127	0.0025	0.9975	96.55
35.5	106,631,109	277,156	0.0026	0.9974	96.31
36.5	97,096,375	273,180	0.0028	0.9972	96.06
37.5	88,156,810	220,860	0.0025	0.9975	95.79
38.5	80,645,478	65,746	0.0008	0.9992	95.55

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	74,722,097	70,936	0.0009	0.9991	95.47
40.5	69,861,125	79,920	0.0011	0.9989	95.38
41.5	65,113,960	100,891	0.0015	0.9985	95.27
42.5	60,935,012	139,981	0.0023	0.9977	95.12
43.5	55,828,674	120,568	0.0022	0.9978	94.91
44.5	51,511,276	654,504	0.0127	0.9873	94.70
45.5	47,448,969	81,642	0.0017	0.9983	93.50
46.5	43,911,768	99,059	0.0023	0.9977	93.34
47.5	40,380,428	82,509	0.0020	0.9980	93.13
48.5	37,037,922	74,287	0.0020	0.9980	92.94
49.5	34,010,007	71,959	0.0021	0.9979	92.75
50.5	31,231,431	66,211	0.0021	0.9979	92.55
51.5	28,448,250	77,120	0.0027	0.9973	92.36
52.5	25,732,333	97,013	0.0038	0.9962	92.11
53.5	22,992,380	48,909	0.0021	0.9979	91.76
54.5	20,817,921	45,203	0.0022	0.9978	91.56
55.5	18,874,450	41,734	0.0022	0.9978	91.37
56.5	16,984,738	36,816	0.0022	0.9978	91.16
57.5	15,241,051	32,076	0.0021	0.9979	90.97
58.5	13,601,153	27,042	0.0020	0.9980	90.77
59.5	11,916,271	22,975	0.0019	0.9981	90.59
60.5	10,351,158	18,422	0.0018	0.9982	90.42
61.5	9,019,423	12,124	0.0013	0.9987	90.26
62.5	7,887,298	8,916	0.0011	0.9989	90.14
63.5	6,827,589	5,756	0.0008	0.9992	90.04
64.5	5,954,668	3,593	0.0006	0.9994	89.96
65.5	5,162,626	2,127	0.0004	0.9996	89.91
66.5	4,300,472	309	0.0001	0.9999	89.87
67.5	4,137,793	16	0.0000	1.0000	89.86
68.5	4,109,295	19	0.0000	1.0000	89.86
69.5	3,521,938	28	0.0000	1.0000	89.86
70.5	2,968,125	61	0.0000	1.0000	89.86
71.5	2,369,429	49	0.0000	1.0000	89.86
72.5	1,890,259	47	0.0000	1.0000	89.86
73.5	1,516,328	63	0.0000	1.0000	89.85
74.5	1,207,238	5	0.0000	1.0000	89.85
75.5	966,151	33	0.0000	1.0000	89.85
76.5	826,330	28	0.0000	1.0000	89.85
77.5	781,329	16	0.0000	1.0000	89.84
78.5	757,320	5	0.0000	1.0000	89.84

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	727,480	14	0.0000	1.0000	89.84
80.5	671,203	12	0.0000	1.0000	89.84
81.5	575,202	32	0.0001	0.9999	89.84
82.5	488,884	21	0.0000	1.0000	89.83
83.5	415,503	24	0.0001	0.9999	89.83
84.5	312,355	21	0.0001	0.9999	89.82
85.5	309,719	23	0.0001	0.9999	89.82
86.5	263,360		0.0000	1.0000	89.81
87.5	214,664		0.0000	1.0000	89.81
88.5	193,993		0.0000	1.0000	89.81
89.5	182,761	434	0.0024	0.9976	89.81
90.5	166,775	42	0.0002	0.9998	89.60
91.5	145,700		0.0000	1.0000	89.58
92.5	116,092	10	0.0001	0.9999	89.58
93.5	85,738		0.0000	1.0000	89.57
94.5	61,738	333	0.0054	0.9946	89.57
95.5	38,337		0.0000	1.0000	89.08
96.5	4,507		0.0000	1.0000	89.08
97.5	4,507		0.0000	1.0000	89.08
98.5	4,507		0.0000	1.0000	89.08
99.5	4,507		0.0000	1.0000	89.08
100.5	4,507		0.0000	1.0000	89.08
101.5	4,507		0.0000	1.0000	89.08
102.5	4,507		0.0000	1.0000	89.08
103.5	4,507		0.0000	1.0000	89.08
104.5	4,507		0.0000	1.0000	89.08
105.5	4,507		0.0000	1.0000	89.08
106.5	4,507		0.0000	1.0000	89.08
107.5	4,507		0.0000	1.0000	89.08
108.5	4,507		0.0000	1.0000	89.08
109.5	4,507		0.0000	1.0000	89.08
110.5	4,507		0.0000	1.0000	89.08
111.5	4,507	4,507	1.0000		89.08
112.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	454,617,177	15,826	0.0000	1.0000	100.00
0.5	431,440,035	26,431	0.0001	0.9999	100.00
1.5	439,611,336	70,804	0.0002	0.9998	99.99
2.5	429,355,044	30,950	0.0001	0.9999	99.97
3.5	421,843,998	63,503	0.0002	0.9998	99.97
4.5	412,097,114	108,980	0.0003	0.9997	99.95
5.5	414,403,972	79,837	0.0002	0.9998	99.93
6.5	414,079,921	135,869	0.0003	0.9997	99.91
7.5	415,278,953	118,218	0.0003	0.9997	99.87
8.5	416,837,103	166,736	0.0004	0.9996	99.85
9.5	419,877,735	128,251	0.0003	0.9997	99.81
10.5	415,532,176	1,332,632	0.0032	0.9968	99.77
11.5	403,546,757	1,384,969	0.0034	0.9966	99.45
12.5	387,225,237	526,327	0.0014	0.9986	99.11
13.5	373,971,592	140,707	0.0004	0.9996	98.98
14.5	359,278,624	120,553	0.0003	0.9997	98.94
15.5	342,900,664	229,621	0.0007	0.9993	98.91
16.5	325,843,290	113,406	0.0003	0.9997	98.84
17.5	310,166,208	104,985	0.0003	0.9997	98.81
18.5	289,290,412	93,054	0.0003	0.9997	98.77
19.5	271,505,578	141,930	0.0005	0.9995	98.74
20.5	261,239,298	224,682	0.0009	0.9991	98.69
21.5	249,159,823	132,824	0.0005	0.9995	98.61
22.5	236,062,097	58,058	0.0002	0.9998	98.55
23.5	225,652,128	55,749	0.0002	0.9998	98.53
24.5	212,738,009	114,764	0.0005	0.9995	98.50
25.5	201,710,671	73,692	0.0004	0.9996	98.45
26.5	187,892,737	69,841	0.0004	0.9996	98.42
27.5	175,324,493	84,955	0.0005	0.9995	98.38
28.5	162,971,145	102,622	0.0006	0.9994	98.33
29.5	152,056,926	100,341	0.0007	0.9993	98.27
30.5	143,755,429	83,161	0.0006	0.9994	98.20
31.5	136,160,584	66,979	0.0005	0.9995	98.15
32.5	129,887,330	314,189	0.0024	0.9976	98.10
33.5	121,257,595	280,182	0.0023	0.9977	97.86
34.5	111,576,842	284,132	0.0025	0.9975	97.64
35.5	102,947,295	267,980	0.0026	0.9974	97.39
36.5	93,968,429	273,180	0.0029	0.9971	97.13
37.5	85,479,721	220,755	0.0026	0.9974	96.85
38.5	78,565,005	65,746	0.0008	0.9992	96.60

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	73,089,472	70,760	0.0010	0.9990	96.52
40.5	68,554,069	79,920	0.0012	0.9988	96.43
41.5	64,100,281	100,891	0.0016	0.9984	96.31
42.5	60,151,312	139,981	0.0023	0.9977	96.16
43.5	55,169,295	120,568	0.0022	0.9978	95.94
44.5	50,875,850	654,504	0.0129	0.9871	95.73
45.5	46,807,922	81,642	0.0017	0.9983	94.50
46.5	43,270,212	99,059	0.0023	0.9977	94.33
47.5	39,771,144	82,509	0.0021	0.9979	94.12
48.5	36,501,591	74,287	0.0020	0.9980	93.92
49.5	33,526,161	71,959	0.0021	0.9979	93.73
50.5	30,821,022	66,211	0.0021	0.9979	93.53
51.5	28,141,031	77,120	0.0027	0.9973	93.33
52.5	25,427,731	97,013	0.0038	0.9962	93.07
53.5	22,734,150	48,909	0.0022	0.9978	92.72
54.5	20,608,417	45,203	0.0022	0.9978	92.52
55.5	18,685,196	41,734	0.0022	0.9978	92.32
56.5	16,806,721	36,816	0.0022	0.9978	92.11
57.5	15,078,600	32,076	0.0021	0.9979	91.91
58.5	13,459,748	27,042	0.0020	0.9980	91.71
59.5	11,804,494	22,975	0.0019	0.9981	91.53
60.5	10,269,744	18,422	0.0018	0.9982	91.35
61.5	8,962,032	12,124	0.0014	0.9986	91.19
62.5	7,853,000	8,916	0.0011	0.9989	91.06
63.5	6,827,154	5,756	0.0008	0.9992	90.96
64.5	5,954,233	3,593	0.0006	0.9994	90.88
65.5	5,162,191	2,127	0.0004	0.9996	90.83
66.5	4,300,037	309	0.0001	0.9999	90.79
67.5	4,137,357	16	0.0000	1.0000	90.78
68.5	4,108,860	19	0.0000	1.0000	90.78
69.5	3,521,938	28	0.0000	1.0000	90.78
70.5	2,968,084	61	0.0000	1.0000	90.78
71.5	2,369,388	49	0.0000	1.0000	90.78
72.5	1,890,209	47	0.0000	1.0000	90.78
73.5	1,516,278	63	0.0000	1.0000	90.78
74.5	1,202,347	5	0.0000	1.0000	90.77
75.5	961,260	33	0.0000	1.0000	90.77
76.5	821,439	28	0.0000	1.0000	90.77
77.5	776,438	16	0.0000	1.0000	90.77
78.5	752,429	5	0.0000	1.0000	90.76

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

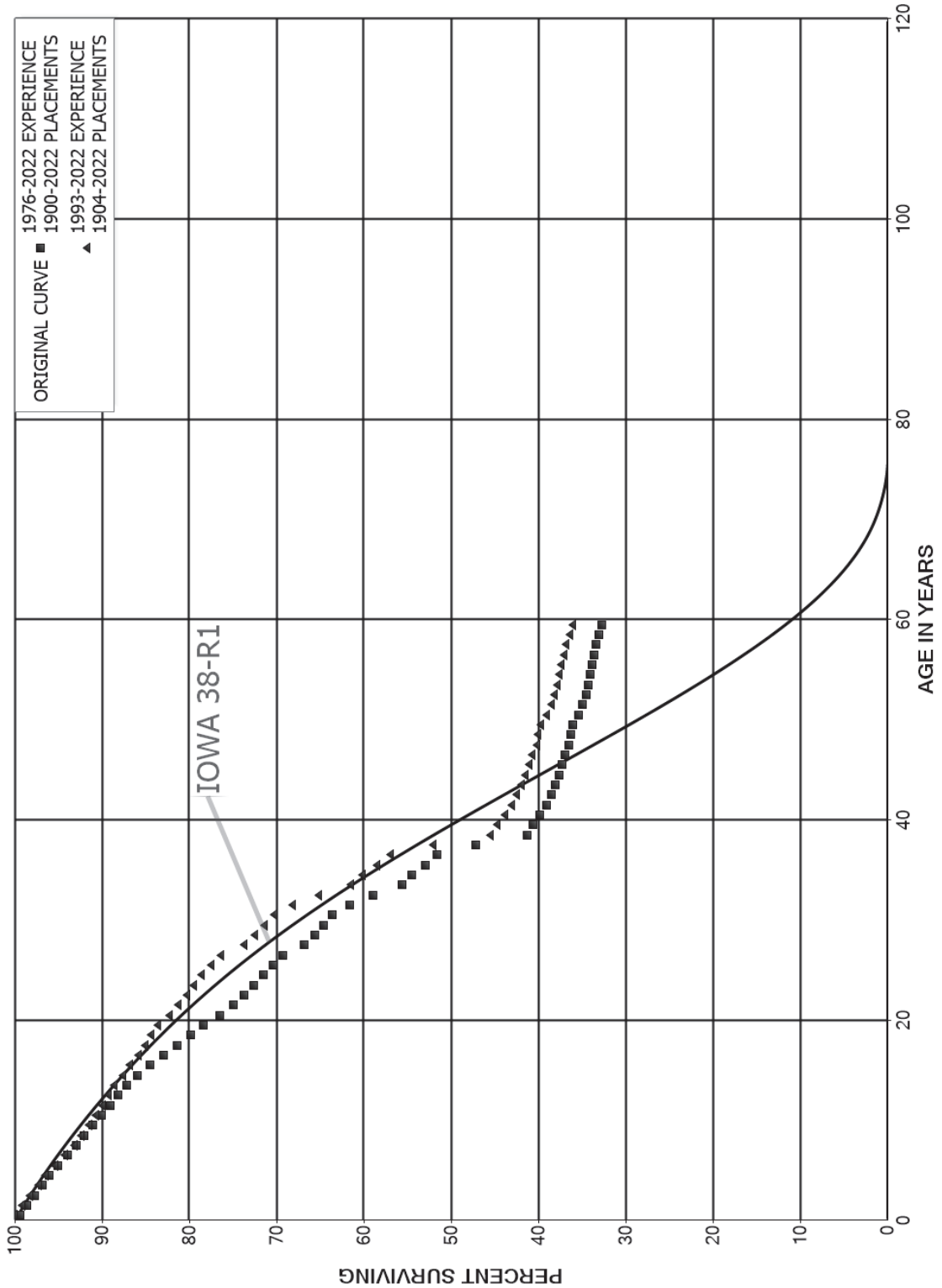
ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	722,589	14	0.0000	1.0000	90.76
80.5	666,312	12	0.0000	1.0000	90.76
81.5	570,311	32	0.0001	0.9999	90.76
82.5	483,993	21	0.0000	1.0000	90.76
83.5	410,612	24	0.0001	0.9999	90.75
84.5	307,505	21	0.0001	0.9999	90.75
85.5	304,868	23	0.0001	0.9999	90.74
86.5	258,519		0.0000	1.0000	90.73
87.5	209,823		0.0000	1.0000	90.73
88.5	193,993		0.0000	1.0000	90.73
89.5	182,761	434	0.0024	0.9976	90.73
90.5	166,775	42	0.0002	0.9998	90.52
91.5	145,700		0.0000	1.0000	90.49
92.5	116,092	10	0.0001	0.9999	90.49
93.5	85,738		0.0000	1.0000	90.49
94.5	61,738	333	0.0054	0.9946	90.49
95.5	38,337		0.0000	1.0000	90.00
96.5	4,507		0.0000	1.0000	90.00
97.5	4,507		0.0000	1.0000	90.00
98.5	4,507		0.0000	1.0000	90.00
99.5	4,507		0.0000	1.0000	90.00
100.5	4,507		0.0000	1.0000	90.00
101.5	4,507		0.0000	1.0000	90.00
102.5	4,507		0.0000	1.0000	90.00
103.5	4,507		0.0000	1.0000	90.00
104.5	4,507		0.0000	1.0000	90.00
105.5	4,507		0.0000	1.0000	90.00
106.5	4,507		0.0000	1.0000	90.00
107.5	4,507		0.0000	1.0000	90.00
108.5	4,507		0.0000	1.0000	90.00
109.5	4,507		0.0000	1.0000	90.00
110.5	4,507		0.0000	1.0000	90.00
111.5	4,507	4,507	1.0000		90.00
112.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	570,552,825	3,624,515	0.0064	0.9936	100.00
0.5	539,310,944	4,042,216	0.0075	0.9925	99.36
1.5	504,034,502	4,443,089	0.0088	0.9912	98.62
2.5	483,498,822	4,287,419	0.0089	0.9911	97.75
3.5	463,815,856	3,859,371	0.0083	0.9917	96.88
4.5	445,490,380	4,766,305	0.0107	0.9893	96.08
5.5	425,137,847	4,759,483	0.0112	0.9888	95.05
6.5	402,827,626	4,454,593	0.0111	0.9889	93.99
7.5	381,416,815	3,623,907	0.0095	0.9905	92.95
8.5	365,196,310	4,133,915	0.0113	0.9887	92.06
9.5	342,760,764	3,740,973	0.0109	0.9891	91.02
10.5	319,712,292	3,338,255	0.0104	0.9896	90.03
11.5	316,082,110	3,423,079	0.0108	0.9892	89.09
12.5	303,238,086	3,245,991	0.0107	0.9893	88.12
13.5	266,175,325	3,839,933	0.0144	0.9856	87.18
14.5	229,076,318	3,686,621	0.0161	0.9839	85.92
15.5	203,164,137	3,885,797	0.0191	0.9809	84.54
16.5	189,835,209	3,521,277	0.0185	0.9815	82.92
17.5	177,097,799	3,285,983	0.0186	0.9814	81.38
18.5	166,609,030	3,105,779	0.0186	0.9814	79.87
19.5	156,781,707	3,767,485	0.0240	0.9760	78.39
20.5	146,060,555	2,852,226	0.0195	0.9805	76.50
21.5	136,843,208	2,350,257	0.0172	0.9828	75.01
22.5	128,268,042	1,996,168	0.0156	0.9844	73.72
23.5	118,142,472	1,668,907	0.0141	0.9859	72.57
24.5	110,871,377	1,796,709	0.0162	0.9838	71.55
25.5	104,058,710	1,668,872	0.0160	0.9840	70.39
26.5	96,833,647	3,392,037	0.0350	0.9650	69.26
27.5	86,799,139	1,579,899	0.0182	0.9818	66.83
28.5	79,702,703	1,259,392	0.0158	0.9842	65.62
29.5	71,288,791	1,117,890	0.0157	0.9843	64.58
30.5	63,009,627	1,897,769	0.0301	0.9699	63.57
31.5	54,683,596	2,349,900	0.0430	0.9570	61.65
32.5	46,358,649	2,624,377	0.0566	0.9434	59.00
33.5	39,531,316	817,877	0.0207	0.9793	55.66
34.5	34,243,577	957,930	0.0280	0.9720	54.51
35.5	28,831,987	754,169	0.0262	0.9738	52.99
36.5	24,194,857	2,050,920	0.0848	0.9152	51.60
37.5	19,109,785	2,383,520	0.1247	0.8753	47.23
38.5	13,696,245	246,584	0.0180	0.9820	41.34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,981,445	211,739	0.0193	0.9807	40.59
40.5	8,581,638	156,832	0.0183	0.9817	39.81
41.5	8,046,933	108,903	0.0135	0.9865	39.08
42.5	7,529,886	96,705	0.0128	0.9872	38.55
43.5	6,555,705	76,203	0.0116	0.9884	38.06
44.5	5,352,614	54,148	0.0101	0.9899	37.61
45.5	4,955,929	32,631	0.0066	0.9934	37.23
46.5	4,721,458	65,235	0.0138	0.9862	36.99
47.5	4,435,205	23,880	0.0054	0.9946	36.48
48.5	4,116,815	29,390	0.0071	0.9929	36.28
49.5	3,683,666	61,305	0.0166	0.9834	36.02
50.5	3,255,062	43,147	0.0133	0.9867	35.42
51.5	2,863,160	32,553	0.0114	0.9886	34.95
52.5	2,646,085	17,304	0.0065	0.9935	34.56
53.5	2,444,645	16,064	0.0066	0.9934	34.33
54.5	2,244,674	16,877	0.0075	0.9925	34.10
55.5	2,022,959	13,836	0.0068	0.9932	33.85
56.5	1,764,121	14,449	0.0082	0.9918	33.62
57.5	1,525,794	14,195	0.0093	0.9907	33.34
58.5	1,307,578	13,520	0.0103	0.9897	33.03
59.5	1,090,689	16,251	0.0149	0.9851	32.69
60.5	850,828	10,336	0.0121	0.9879	32.20
61.5	665,397	18,006	0.0271	0.9729	31.81
62.5	532,862	4,953	0.0093	0.9907	30.95
63.5	444,402	4,218	0.0095	0.9905	30.66
64.5	364,178	7,559	0.0208	0.9792	30.37
65.5	286,433	5,807	0.0203	0.9797	29.74
66.5	233,550	4,062	0.0174	0.9826	29.14
67.5	193,788	1,431	0.0074	0.9926	28.63
68.5	174,944	226	0.0013	0.9987	28.42
69.5	7,575		0.0000	1.0000	28.38
70.5	7,575		0.0000	1.0000	28.38
71.5	7,575		0.0000	1.0000	28.38
72.5	7,575		0.0000	1.0000	28.38
73.5	7,575		0.0000	1.0000	28.38
74.5	7,575		0.0000	1.0000	28.38
75.5	8,131		0.0000	1.0000	28.38
76.5	8,131		0.0000	1.0000	28.38
77.5	8,131		0.0000	1.0000	28.38
78.5	8,131		0.0000	1.0000	28.38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1976-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,131		0.0000	1.0000	28.38
80.5	8,131		0.0000	1.0000	28.38
81.5	8,131		0.0000	1.0000	28.38
82.5	8,131		0.0000	1.0000	28.38
83.5	8,131		0.0000	1.0000	28.38
84.5	8,131		0.0000	1.0000	28.38
85.5	8,131		0.0000	1.0000	28.38
86.5	8,131		0.0000	1.0000	28.38
87.5	8,131		0.0000	1.0000	28.38
88.5	8,131		0.0000	1.0000	28.38
89.5	8,131		0.0000	1.0000	28.38
90.5	8,131	556	0.0684	0.9316	28.38
91.5	7,575		0.0000	1.0000	26.44
92.5	7,575		0.0000	1.0000	26.44
93.5	7,575		0.0000	1.0000	26.44
94.5	7,575		0.0000	1.0000	26.44
95.5	7,575		0.0000	1.0000	26.44
96.5	7,575		0.0000	1.0000	26.44
97.5	7,575		0.0000	1.0000	26.44
98.5	7,575	7,575	1.0000		26.44
99.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	489,104,645	386,267	0.0008	0.9992	100.00
0.5	468,231,784	3,824,406	0.0082	0.9918	99.92
1.5	439,195,763	4,220,622	0.0096	0.9904	99.10
2.5	422,655,547	4,013,388	0.0095	0.9905	98.15
3.5	405,155,419	3,584,111	0.0088	0.9912	97.22
4.5	390,510,343	4,527,532	0.0116	0.9884	96.36
5.5	374,351,834	4,394,076	0.0117	0.9883	95.24
6.5	355,758,811	3,825,493	0.0108	0.9892	94.13
7.5	338,373,568	2,859,616	0.0085	0.9915	93.11
8.5	325,194,781	3,180,041	0.0098	0.9902	92.33
9.5	307,086,637	2,693,430	0.0088	0.9912	91.42
10.5	286,256,262	2,312,184	0.0081	0.9919	90.62
11.5	281,565,565	2,285,618	0.0081	0.9919	89.89
12.5	268,192,970	1,967,780	0.0073	0.9927	89.16
13.5	232,372,435	2,494,723	0.0107	0.9893	88.51
14.5	199,293,365	1,959,776	0.0098	0.9902	87.56
15.5	177,283,592	1,964,282	0.0111	0.9889	86.69
16.5	166,068,825	1,415,343	0.0085	0.9915	85.73
17.5	155,732,111	1,283,459	0.0082	0.9918	85.00
18.5	147,745,073	1,413,878	0.0096	0.9904	84.30
19.5	142,810,146	2,336,940	0.0164	0.9836	83.50
20.5	135,763,012	1,665,784	0.0123	0.9877	82.13
21.5	128,934,462	1,495,389	0.0116	0.9884	81.12
22.5	121,269,493	1,251,659	0.0103	0.9897	80.18
23.5	112,134,327	1,271,599	0.0113	0.9887	79.35
24.5	105,498,513	1,458,455	0.0138	0.9862	78.45
25.5	99,391,026	1,461,015	0.0147	0.9853	77.37
26.5	92,737,766	3,232,290	0.0349	0.9651	76.23
27.5	84,122,101	1,403,020	0.0167	0.9833	73.57
28.5	77,482,881	1,157,467	0.0149	0.9851	72.35
29.5	69,461,066	1,051,756	0.0151	0.9849	71.27
30.5	61,564,810	1,870,405	0.0304	0.9696	70.19
31.5	53,749,113	2,331,432	0.0434	0.9566	68.06
32.5	45,700,108	2,608,893	0.0571	0.9429	65.10
33.5	38,983,344	807,537	0.0207	0.9793	61.39
34.5	33,792,257	951,589	0.0282	0.9718	60.12
35.5	28,478,863	751,335	0.0264	0.9736	58.42
36.5	23,900,952	2,049,994	0.0858	0.9142	56.88
37.5	18,857,111	2,382,551	0.1263	0.8737	52.00
38.5	13,465,901	245,228	0.0182	0.9818	45.43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,967,589	210,907	0.0192	0.9808	44.60
40.5	8,569,601	156,014	0.0182	0.9818	43.75
41.5	8,038,378	108,227	0.0135	0.9865	42.95
42.5	7,524,548	96,236	0.0128	0.9872	42.37
43.5	6,552,701	75,831	0.0116	0.9884	41.83
44.5	5,351,470	53,777	0.0100	0.9900	41.35
45.5	4,954,626	32,238	0.0065	0.9935	40.93
46.5	4,719,953	64,737	0.0137	0.9863	40.66
47.5	4,433,742	23,343	0.0053	0.9947	40.11
48.5	4,115,592	28,924	0.0070	0.9930	39.90
49.5	3,682,684	60,930	0.0165	0.9835	39.62
50.5	3,254,312	42,829	0.0132	0.9868	38.96
51.5	2,862,691	32,318	0.0113	0.9887	38.45
52.5	2,645,830	17,173	0.0065	0.9935	38.01
53.5	2,444,513	15,980	0.0065	0.9935	37.77
54.5	2,244,625	16,837	0.0075	0.9925	37.52
55.5	2,022,947	13,829	0.0068	0.9932	37.24
56.5	1,764,116	14,448	0.0082	0.9918	36.98
57.5	1,525,790	14,191	0.0093	0.9907	36.68
58.5	1,307,578	13,520	0.0103	0.9897	36.34
59.5	1,090,689	16,251	0.0149	0.9851	35.96
60.5	850,828	10,336	0.0121	0.9879	35.43
61.5	657,821	18,006	0.0274	0.9726	35.00
62.5	525,287	4,953	0.0094	0.9906	34.04
63.5	436,827	4,218	0.0097	0.9903	33.72
64.5	356,603	7,559	0.0212	0.9788	33.39
65.5	278,858	5,807	0.0208	0.9792	32.68
66.5	225,975	4,062	0.0180	0.9820	32.00
67.5	186,213	1,431	0.0077	0.9923	31.43
68.5	167,369	226	0.0013	0.9987	31.19
69.5					31.15
70.5					
71.5					
72.5					
73.5					
74.5					
75.5					
76.5					
77.5					
78.5	7,575		0.0000		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

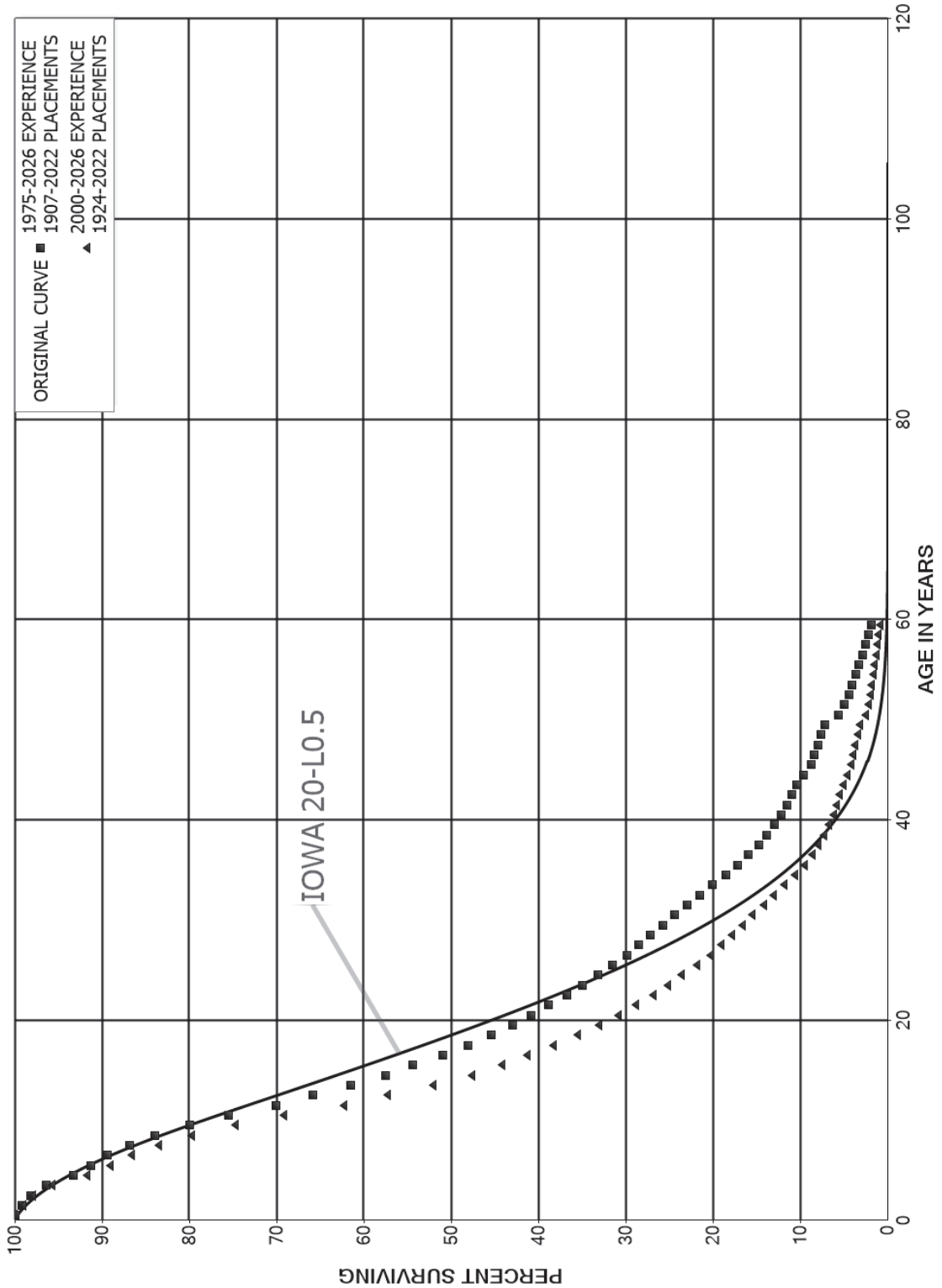
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	7,575		0.0000		
80.5	7,575		0.0000		
81.5	7,575		0.0000		
82.5	7,575		0.0000		
83.5	7,575		0.0000		
84.5	7,575		0.0000		
85.5	7,575		0.0000		
86.5	7,575		0.0000		
87.5	7,575		0.0000		
88.5	7,575		0.0000		
89.5	7,575		0.0000		
90.5	7,575		0.0000		
91.5	7,575		0.0000		
92.5	7,575		0.0000		
93.5	7,575		0.0000		
94.5	7,575		0.0000		
95.5	7,575		0.0000		
96.5	7,575		0.0000		
97.5	7,575		0.0000		
98.5	7,575	7,575	1.0000		
99.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT
ACCOUNT 370.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1907-2022 EXPERIENCE BAND 1975-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	438,681,894	295,389	0.0007	0.9993	100.00
0.5	441,159,914	3,564,590	0.0081	0.9919	99.93
1.5	441,563,034	4,183,872	0.0095	0.9905	99.13
2.5	440,058,392	7,864,058	0.0179	0.9821	98.19
3.5	434,553,419	14,138,418	0.0325	0.9675	96.43
4.5	364,351,737	7,870,245	0.0216	0.9784	93.29
5.5	341,705,007	7,195,061	0.0211	0.9789	91.28
6.5	328,805,038	9,185,298	0.0279	0.9721	89.36
7.5	313,395,452	10,679,459	0.0341	0.9659	86.86
8.5	300,221,082	14,060,582	0.0468	0.9532	83.90
9.5	278,452,204	15,362,625	0.0552	0.9448	79.97
10.5	260,115,883	18,865,303	0.0725	0.9275	75.56
11.5	240,197,075	14,405,599	0.0600	0.9400	70.08
12.5	227,756,325	15,133,373	0.0664	0.9336	65.88
13.5	215,043,375	13,952,678	0.0649	0.9351	61.50
14.5	202,930,207	11,105,510	0.0547	0.9453	57.51
15.5	193,249,290	12,102,490	0.0626	0.9374	54.36
16.5	182,596,699	10,445,998	0.0572	0.9428	50.96
17.5	173,507,293	9,610,996	0.0554	0.9446	48.04
18.5	165,010,331	8,677,053	0.0526	0.9474	45.38
19.5	157,215,207	7,757,623	0.0493	0.9507	42.99
20.5	150,145,070	7,639,034	0.0509	0.9491	40.87
21.5	144,312,614	7,746,238	0.0537	0.9463	38.79
22.5	137,676,434	6,406,198	0.0465	0.9535	36.71
23.5	132,404,890	6,708,257	0.0507	0.9493	35.00
24.5	135,130,836	7,235,357	0.0535	0.9465	33.23
25.5	128,561,397	6,744,987	0.0525	0.9475	31.45
26.5	122,593,756	5,483,874	0.0447	0.9553	29.80
27.5	117,661,128	5,533,650	0.0470	0.9530	28.47
28.5	112,311,694	5,781,737	0.0515	0.9485	27.13
29.5	106,700,666	5,650,458	0.0530	0.9470	25.73
30.5	101,096,293	6,098,517	0.0603	0.9397	24.37
31.5	95,044,049	5,966,047	0.0628	0.9372	22.90
32.5	89,151,237	5,993,686	0.0672	0.9328	21.46
33.5	83,386,979	6,456,881	0.0774	0.9226	20.02
34.5	77,109,679	5,415,823	0.0702	0.9298	18.47
35.5	71,834,507	4,985,313	0.0694	0.9306	17.17
36.5	67,024,320	5,055,754	0.0754	0.9246	15.98
37.5	62,159,485	3,824,592	0.0615	0.9385	14.77
38.5	58,402,049	3,804,464	0.0651	0.9349	13.87

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1907-2022 EXPERIENCE BAND 1975-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	54,656,052	3,189,142	0.0583	0.9417	12.96
40.5	51,501,331	2,804,295	0.0545	0.9455	12.21
41.5	48,716,564	2,328,661	0.0478	0.9522	11.54
42.5	46,393,563	2,507,586	0.0541	0.9459	10.99
43.5	43,904,858	3,385,715	0.0771	0.9229	10.40
44.5	40,540,326	3,672,450	0.0906	0.9094	9.59
45.5	36,887,653	1,562,392	0.0424	0.9576	8.72
46.5	35,343,606	1,511,497	0.0428	0.9572	8.36
47.5	33,849,001	1,566,726	0.0463	0.9537	8.00
48.5	32,295,154	1,863,802	0.0577	0.9423	7.63
49.5	30,440,884	6,827,669	0.2243	0.7757	7.19
50.5	23,620,386	2,526,665	0.1070	0.8930	5.58
51.5	21,098,059	2,259,136	0.1071	0.8929	4.98
52.5	18,840,938	1,695,411	0.0900	0.9100	4.45
53.5	17,146,229	1,780,181	0.1038	0.8962	4.05
54.5	15,366,249	1,643,810	0.1070	0.8930	3.63
55.5	13,722,456	1,705,871	0.1243	0.8757	3.24
56.5	12,016,939	1,419,328	0.1181	0.8819	2.84
57.5	10,597,611	1,192,088	0.1125	0.8875	2.50
58.5	9,405,522	1,396,118	0.1484	0.8516	2.22
59.5	8,009,404	1,307,375	0.1632	0.8368	1.89
60.5	6,702,029	1,105,819	0.1650	0.8350	1.58
61.5	5,596,210	998,530	0.1784	0.8216	1.32
62.5	4,597,679	823,992	0.1792	0.8208	1.08
63.5	3,773,688	588,745	0.1560	0.8440	0.89
64.5	3,184,942	519,520	0.1631	0.8369	0.75
65.5	2,665,422	413,583	0.1552	0.8448	0.63
66.5	2,251,840	289,331	0.1285	0.8715	0.53
67.5	1,962,509	208,592	0.1063	0.8937	0.46
68.5	1,753,917	165,216	0.0942	0.9058	0.41
69.5	1,588,701	539,318	0.3395	0.6605	0.37
70.5	1,049,383	307,956	0.2935	0.7065	0.25
71.5	741,427	192,424	0.2595	0.7405	0.17
72.5	549,003	428,623	0.7807	0.2193	0.13
73.5	120,380	25,158	0.2090	0.7910	0.03
74.5	95,223	24,656	0.2589	0.7411	0.02
75.5	70,567	13,115	0.1859	0.8141	0.02
76.5	57,452	8,110	0.1412	0.8588	0.01
77.5	49,342	2,593	0.0526	0.9474	0.01
78.5	46,749	7,747	0.1657	0.8343	0.01

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1907-2022 EXPERIENCE BAND 1975-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	39,002	7,939	0.2036	0.7964	0.01
80.5	31,062	7,939	0.2556	0.7444	0.01
81.5	23,123	7,931	0.3430	0.6570	0.01
82.5	15,192	6,144	0.4044	0.5956	0.00
83.5	9,048	4,546	0.5025	0.4975	0.00
84.5	4,502	2,752	0.6114	0.3886	0.00
85.5	1,750	1,524	0.8709	0.1291	0.00
86.5	226	191	0.8476	0.1524	0.00
87.5	34	34	1.0000		0.00
88.5					

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2022 EXPERIENCE BAND 2000-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	318,194,459	35,225	0.0001	0.9999	100.00
0.5	328,606,198	3,281,762	0.0100	0.9900	99.99
1.5	331,613,666	3,846,738	0.0116	0.9884	98.99
2.5	332,250,862	7,524,605	0.0226	0.9774	97.84
3.5	329,411,467	13,804,777	0.0419	0.9581	95.63
4.5	263,529,903	7,521,022	0.0285	0.9715	91.62
5.5	247,377,766	6,842,002	0.0277	0.9723	89.00
6.5	239,371,174	8,837,623	0.0369	0.9631	86.54
7.5	228,897,234	10,342,421	0.0452	0.9548	83.35
8.5	219,400,200	13,689,738	0.0624	0.9376	79.58
9.5	201,415,040	15,021,677	0.0746	0.9254	74.62
10.5	187,393,888	18,523,083	0.0988	0.9012	69.05
11.5	171,844,564	14,048,771	0.0818	0.9182	62.23
12.5	163,229,732	14,772,384	0.0905	0.9095	57.14
13.5	153,286,533	13,120,155	0.0856	0.9144	51.97
14.5	147,697,350	10,741,828	0.0727	0.9273	47.52
15.5	140,690,997	9,076,820	0.0645	0.9355	44.06
16.5	134,488,444	10,061,385	0.0748	0.9252	41.22
17.5	127,021,161	9,207,710	0.0725	0.9275	38.14
18.5	119,381,585	8,288,054	0.0694	0.9306	35.37
19.5	112,813,732	7,391,117	0.0655	0.9345	32.92
20.5	108,804,646	7,274,687	0.0669	0.9331	30.76
21.5	105,954,227	7,355,817	0.0694	0.9306	28.70
22.5	99,936,751	5,982,621	0.0599	0.9401	26.71
23.5	95,159,838	6,245,120	0.0656	0.9344	25.11
24.5	90,225,515	6,736,533	0.0747	0.9253	23.46
25.5	85,161,013	6,197,319	0.0728	0.9272	21.71
26.5	81,318,122	4,905,478	0.0603	0.9397	20.13
27.5	78,586,827	4,949,373	0.0630	0.9370	18.92
28.5	75,651,044	5,188,581	0.0686	0.9314	17.73
29.5	71,519,800	5,039,976	0.0705	0.9295	16.51
30.5	67,585,127	5,525,437	0.0818	0.9182	15.35
31.5	63,235,192	5,391,216	0.0853	0.9147	14.09
32.5	59,066,790	5,422,171	0.0918	0.9082	12.89
33.5	55,088,815	5,894,860	0.1070	0.8930	11.71
34.5	50,577,623	4,882,994	0.0965	0.9035	10.45
35.5	46,941,400	4,477,378	0.0954	0.9046	9.45
36.5	43,743,955	3,719,479	0.0850	0.9150	8.54
37.5	41,494,996	3,315,041	0.0799	0.9201	7.82
38.5	39,285,308	3,305,925	0.0842	0.9158	7.19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2022 EXPERIENCE BAND 2000-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,141,624	2,724,163	0.0733	0.9267	6.59
40.5	35,275,135	2,375,366	0.0673	0.9327	6.10
41.5	33,707,401	1,947,530	0.0578	0.9422	5.69
42.5	32,498,498	2,191,278	0.0674	0.9326	5.36
43.5	30,795,185	3,129,340	0.1016	0.8984	5.00
44.5	28,029,251	3,018,357	0.1077	0.8923	4.49
45.5	25,237,342	1,419,052	0.0562	0.9438	4.01
46.5	24,360,900	1,410,906	0.0579	0.9421	3.79
47.5	23,381,286	1,490,690	0.0638	0.9362	3.57
48.5	22,231,238	1,803,313	0.0811	0.9189	3.34
49.5	29,286,620	6,776,487	0.2314	0.7686	3.07
50.5	22,652,958	2,485,467	0.1097	0.8903	2.36
51.5	20,336,990	2,226,202	0.1095	0.8905	2.10
52.5	18,234,069	1,666,104	0.0914	0.9086	1.87
53.5	16,610,624	1,760,487	0.1060	0.8940	1.70
54.5	14,891,240	1,631,426	0.1096	0.8904	1.52
55.5	13,271,043	1,701,442	0.1282	0.8718	1.35
56.5	11,581,506	1,418,578	0.1225	0.8775	1.18
57.5	10,182,534	1,191,732	0.1170	0.8830	1.03
58.5	9,055,487	1,395,984	0.1542	0.8458	0.91
59.5	7,713,823	1,307,038	0.1694	0.8306	0.77
60.5	6,452,275	1,105,565	0.1713	0.8287	0.64
61.5	5,407,586	998,436	0.1846	0.8154	0.53
62.5	4,478,842	823,808	0.1839	0.8161	0.43
63.5	3,680,060	588,651	0.1600	0.8400	0.35
64.5	3,113,880	519,432	0.1668	0.8332	0.30
65.5	2,608,413	413,318	0.1585	0.8415	0.25
66.5	2,202,626	288,958	0.1312	0.8688	0.21
67.5	1,916,190	208,563	0.1088	0.8912	0.18
68.5	1,715,316	165,216	0.0963	0.9037	0.16
69.5	1,558,724	539,260	0.3460	0.6540	0.15
70.5	1,027,405	307,926	0.2997	0.7003	0.10
71.5	726,615	192,307	0.2647	0.7353	0.07
72.5	540,390	428,623	0.7932	0.2068	0.05
73.5	116,169	25,085	0.2159	0.7841	0.01
74.5	93,704	24,656	0.2631	0.7369	0.01
75.5	70,567	13,115	0.1859	0.8141	0.01
76.5	57,452	8,110	0.1412	0.8588	0.00
77.5	49,342	2,593	0.0526	0.9474	0.00
78.5	46,749	7,747	0.1657	0.8343	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

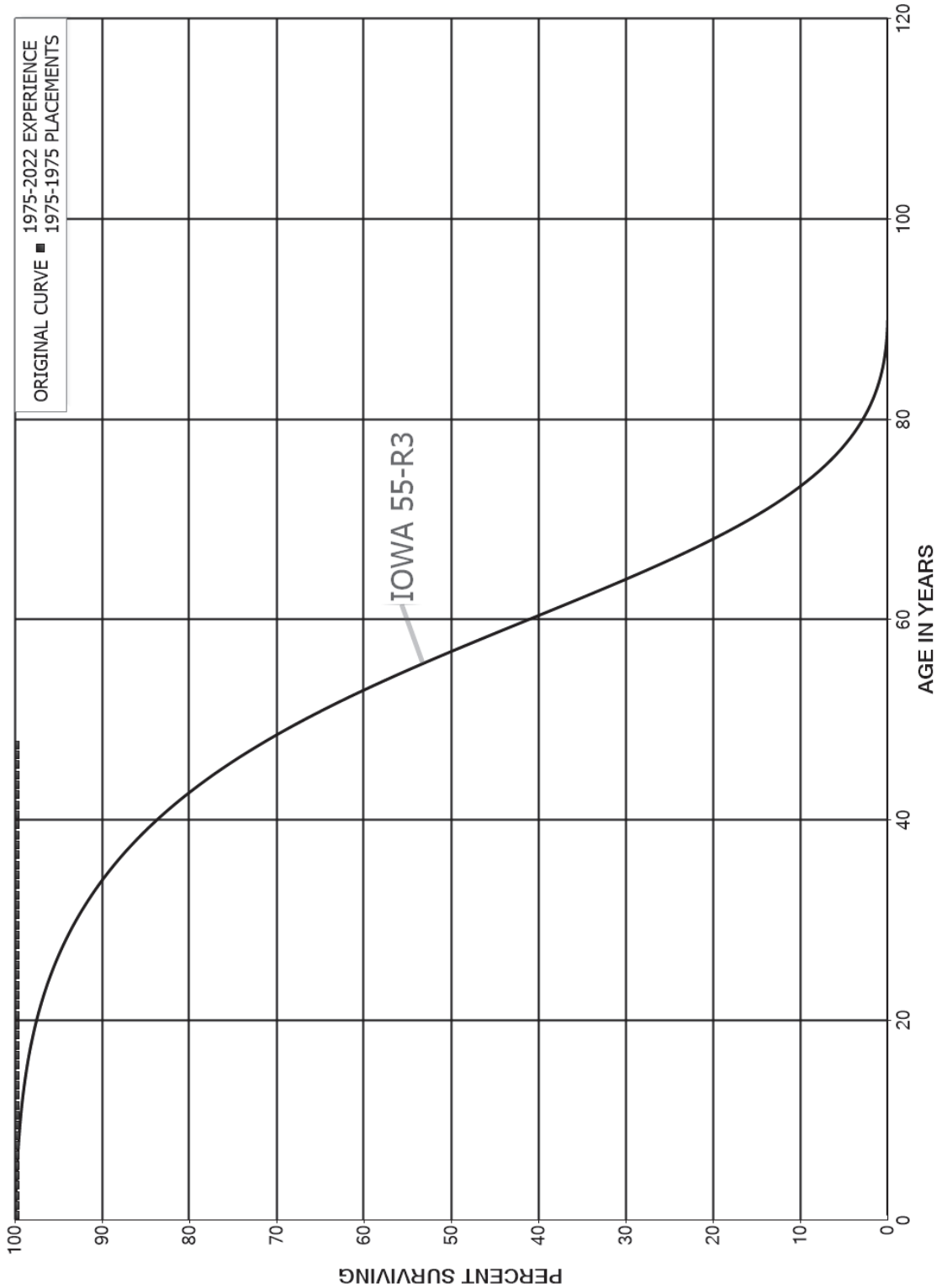
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2022 EXPERIENCE BAND 2000-2026

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	39,002	7,939	0.2036	0.7964	0.00
80.5	31,062	7,939	0.2556	0.7444	0.00
81.5	23,123	7,931	0.3430	0.6570	0.00
82.5	15,192	6,144	0.4044	0.5956	0.00
83.5	9,048	4,546	0.5025	0.4975	0.00
84.5	4,502	2,752	0.6114	0.3886	0.00
85.5	1,750	1,524	0.8709	0.1291	0.00
86.5	226	191	0.8476	0.1524	0.00
87.5	34	34	1.0000		0.00
88.5					

GAS PLANT

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 304.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 304.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-1975 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	41,239		0.0000	1.0000	100.00
0.5	41,239		0.0000	1.0000	100.00
1.5	41,239		0.0000	1.0000	100.00
2.5	41,239		0.0000	1.0000	100.00
3.5	41,239		0.0000	1.0000	100.00
4.5	41,239		0.0000	1.0000	100.00
5.5	41,239		0.0000	1.0000	100.00
6.5	41,239		0.0000	1.0000	100.00
7.5	41,239		0.0000	1.0000	100.00
8.5	41,239		0.0000	1.0000	100.00
9.5	41,239		0.0000	1.0000	100.00
10.5	41,239		0.0000	1.0000	100.00
11.5	41,239		0.0000	1.0000	100.00
12.5	41,239		0.0000	1.0000	100.00
13.5	41,239		0.0000	1.0000	100.00
14.5	41,239		0.0000	1.0000	100.00
15.5	41,239		0.0000	1.0000	100.00
16.5	41,239		0.0000	1.0000	100.00
17.5	41,239		0.0000	1.0000	100.00
18.5	41,239		0.0000	1.0000	100.00
19.5	41,239		0.0000	1.0000	100.00
20.5	41,239		0.0000	1.0000	100.00
21.5	41,239		0.0000	1.0000	100.00
22.5	41,239		0.0000	1.0000	100.00
23.5	41,239		0.0000	1.0000	100.00
24.5	41,239		0.0000	1.0000	100.00
25.5	41,239		0.0000	1.0000	100.00
26.5	41,239		0.0000	1.0000	100.00
27.5	41,239		0.0000	1.0000	100.00
28.5	41,239		0.0000	1.0000	100.00
29.5	41,239		0.0000	1.0000	100.00
30.5	41,239		0.0000	1.0000	100.00
31.5	41,239		0.0000	1.0000	100.00
32.5	41,239		0.0000	1.0000	100.00
33.5	41,239		0.0000	1.0000	100.00
34.5	41,239		0.0000	1.0000	100.00
35.5	41,239		0.0000	1.0000	100.00
36.5	41,239		0.0000	1.0000	100.00
37.5	41,239		0.0000	1.0000	100.00
38.5	41,239		0.0000	1.0000	100.00

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

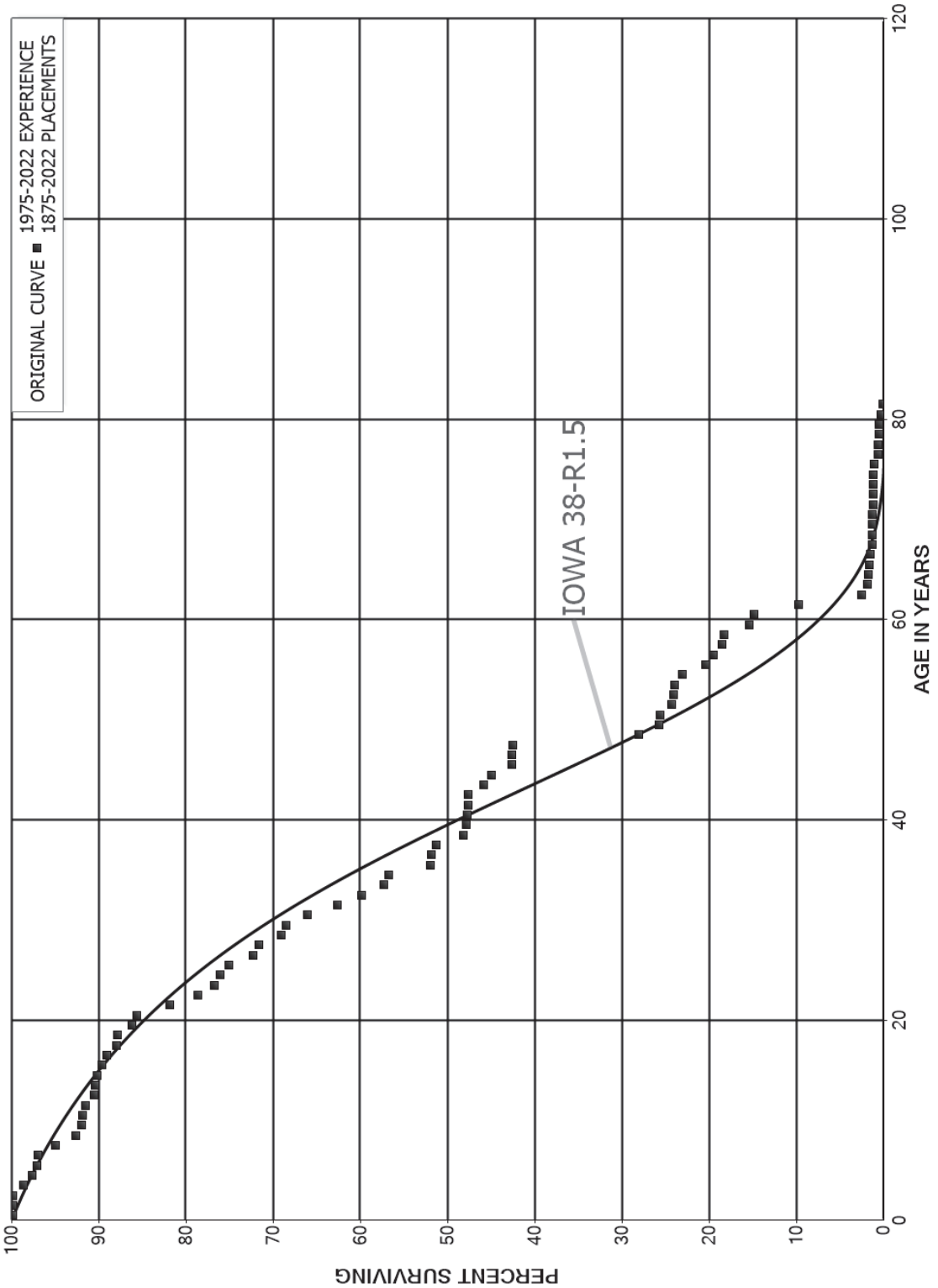
ACCOUNT 304.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1975-1975 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	41,239		0.0000	1.0000	100.00
40.5	41,239		0.0000	1.0000	100.00
41.5	41,239		0.0000	1.0000	100.00
42.5	41,239		0.0000	1.0000	100.00
43.5	41,239		0.0000	1.0000	100.00
44.5	41,239		0.0000	1.0000	100.00
45.5	41,239		0.0000	1.0000	100.00
46.5	41,239		0.0000	1.0000	100.00
47.5					100.00

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1875-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,554,585	12,731	0.0013	0.9987	100.00
0.5	11,090,508		0.0000	1.0000	99.87
1.5	11,212,744	18	0.0000	1.0000	99.87
2.5	11,211,130	134,955	0.0120	0.9880	99.87
3.5	11,206,119	122,584	0.0109	0.9891	98.66
4.5	11,125,152	62,358	0.0056	0.9944	97.59
5.5	11,065,623	15,988	0.0014	0.9986	97.04
6.5	11,051,916	224,198	0.0203	0.9797	96.90
7.5	10,839,384	263,565	0.0243	0.9757	94.93
8.5	10,620,907	76,693	0.0072	0.9928	92.62
9.5	10,609,498	14,103	0.0013	0.9987	91.96
10.5	10,718,677	36,498	0.0034	0.9966	91.83
11.5	11,037,967	116,197	0.0105	0.9895	91.52
12.5	10,424,943	18,575	0.0018	0.9982	90.56
13.5	10,237,938	24,778	0.0024	0.9976	90.40
14.5	10,171,091	63,980	0.0063	0.9937	90.18
15.5	9,443,793	60,540	0.0064	0.9936	89.61
16.5	9,408,812	109,509	0.0116	0.9884	89.03
17.5	9,601,586	17,672	0.0018	0.9982	88.00
18.5	9,716,341	179,529	0.0185	0.9815	87.84
19.5	9,963,080	70,456	0.0071	0.9929	86.21
20.5	10,466,189	457,081	0.0437	0.9563	85.60
21.5	10,270,566	411,644	0.0401	0.9599	81.87
22.5	10,358,279	239,755	0.0231	0.9769	78.58
23.5	10,193,732	98,000	0.0096	0.9904	76.77
24.5	7,812,310	95,101	0.0122	0.9878	76.03
25.5	8,004,156	303,742	0.0379	0.9621	75.10
26.5	6,523,599	58,320	0.0089	0.9911	72.25
27.5	6,496,711	233,312	0.0359	0.9641	71.61
28.5	6,283,342	51,361	0.0082	0.9918	69.03
29.5	6,245,666	215,671	0.0345	0.9655	68.47
30.5	6,025,637	314,191	0.0521	0.9479	66.11
31.5	5,750,915	261,373	0.0454	0.9546	62.66
32.5	5,433,077	233,702	0.0430	0.9570	59.81
33.5	5,184,305	42,678	0.0082	0.9918	57.24
34.5	5,143,814	434,367	0.0844	0.9156	56.77
35.5	4,709,447	9,880	0.0021	0.9979	51.97
36.5	4,527,154	53,403	0.0118	0.9882	51.86
37.5	4,336,478	259,714	0.0599	0.9401	51.25
38.5	4,029,432	25,760	0.0064	0.9936	48.18

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1875-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,869,403	15,250	0.0039	0.9961	47.88
40.5	3,801,648	9,388	0.0025	0.9975	47.69
41.5	3,807,954	347	0.0001	0.9999	47.57
42.5	3,539,280	130,446	0.0369	0.9631	47.56
43.5	3,319,904	60,084	0.0181	0.9819	45.81
44.5	2,798,586	148,630	0.0531	0.9469	44.98
45.5	2,083,821	1,395	0.0007	0.9993	42.59
46.5	2,030,914	2,022	0.0010	0.9990	42.56
47.5	112,785	38,440	0.3408	0.6592	42.52
48.5	185,858	15,171	0.0816	0.9184	28.03
49.5	288,264	900	0.0031	0.9969	25.74
50.5	324,969	16,756	0.0516	0.9484	25.66
51.5	351,105	3,376	0.0096	0.9904	24.34
52.5	387,319	1,538	0.0040	0.9960	24.10
53.5	408,150	15,362	0.0376	0.9624	24.01
54.5	397,899	47,569	0.1195	0.8805	23.10
55.5	390,524	15,827	0.0405	0.9595	20.34
56.5	400,874	21,060	0.0525	0.9475	19.52
57.5	383,093	3,914	0.0102	0.9898	18.49
58.5	390,085	61,966	0.1589	0.8411	18.30
59.5	328,120	11,829	0.0361	0.9639	15.40
60.5	316,290	108,964	0.3445	0.6555	14.84
61.5	210,321	156,052	0.7420	0.2580	9.73
62.5	89,419	24,991	0.2795	0.7205	2.51
63.5	64,964	3,123	0.0481	0.9519	1.81
64.5	74,978	2,608	0.0348	0.9652	1.72
65.5	117,425	8,625	0.0735	0.9265	1.66
66.5	120,258	17,838	0.1483	0.8517	1.54
67.5	108,056	1,952	0.0181	0.9819	1.31
68.5	106,104	1,574	0.0148	0.9852	1.29
69.5	189,908	5,683	0.0299	0.9701	1.27
70.5	254,374	2,398	0.0094	0.9906	1.23
71.5	259,958	1,584	0.0061	0.9939	1.22
72.5	370,485	10,842	0.0293	0.9707	1.21
73.5	371,036	2,329	0.0063	0.9937	1.18
74.5	368,708	35,676	0.0968	0.9032	1.17
75.5	333,031	143,426	0.4307	0.5693	1.06
76.5	189,605	12,680	0.0669	0.9331	0.60
77.5	176,925	9,104	0.0515	0.9485	0.56
78.5	167,821		0.0000	1.0000	0.53

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

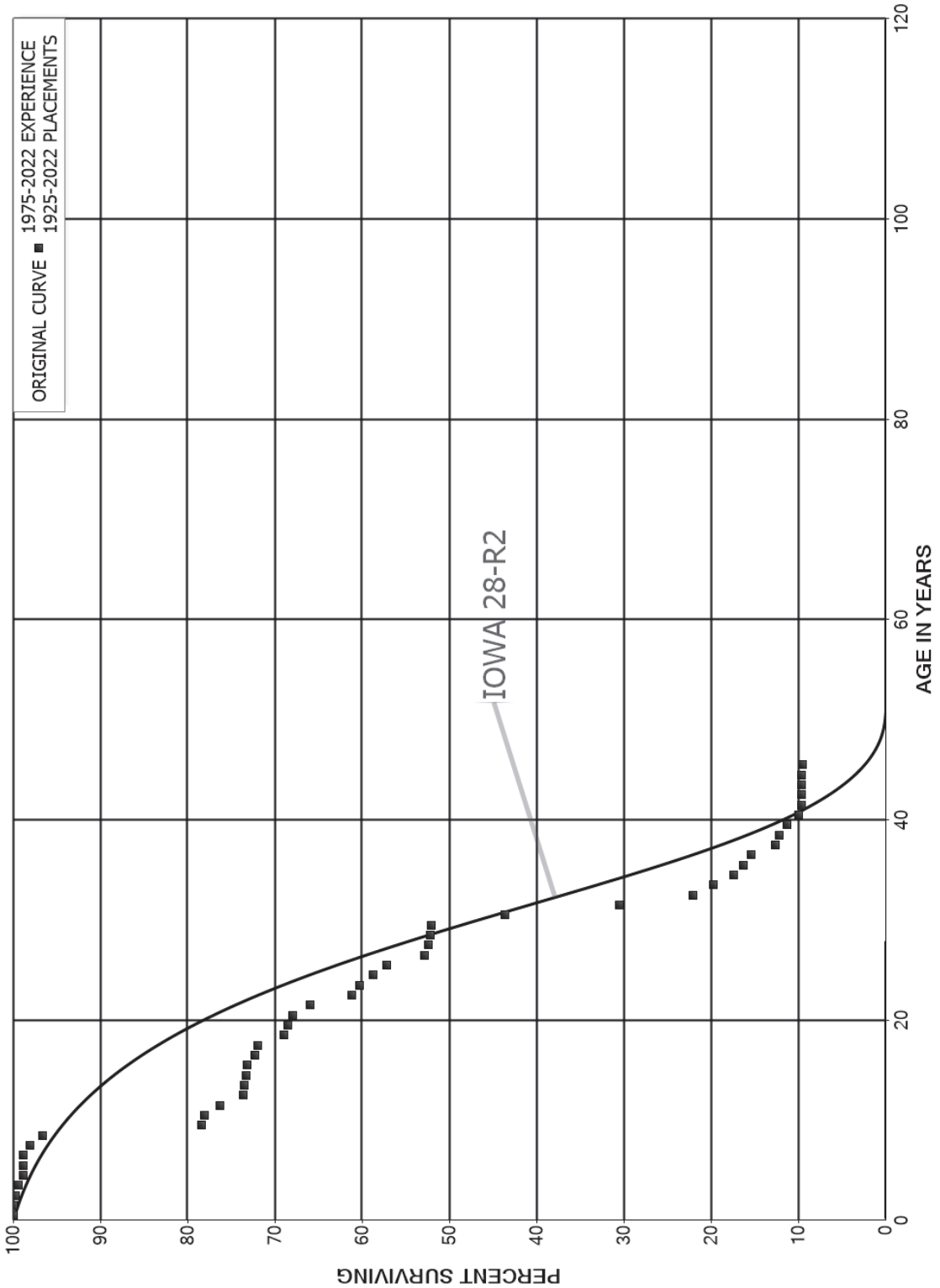
ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1875-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	167,821	80,136	0.4775	0.5225	0.53
80.5	87,685	69,018	0.7871	0.2129	0.28
81.5	18,668	5,750	0.3080	0.6920	0.06
82.5	12,918	3,130	0.2423	0.7577	0.04
83.5	15,125	1,870	0.1236	0.8764	0.03
84.5	22,848		0.0000	1.0000	0.03
85.5	22,848		0.0000	1.0000	0.03
86.5	22,848	5,337	0.2336	0.7664	0.03
87.5	17,511	9,594	0.5479	0.4521	0.02
88.5	7,918		0.0000	1.0000	0.01
89.5	7,918		0.0000	1.0000	0.01
90.5	7,918		0.0000	1.0000	0.01
91.5	7,918		0.0000	1.0000	0.01
92.5	7,918		0.0000	1.0000	0.01
93.5	7,918		0.0000	1.0000	0.01
94.5	7,918		0.0000	1.0000	0.01
95.5	7,918	3,428	0.4330	0.5670	0.01
96.5	4,489	4,489	1.0000		0.01
97.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 307.00 OTHER POWER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1925-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,498,269		0.0000	1.0000	100.00
0.5	4,508,247		0.0000	1.0000	100.00
1.5	4,520,931	10,032	0.0022	0.9978	100.00
2.5	4,486,750	19,484	0.0043	0.9957	99.78
3.5	4,444,489	22,384	0.0050	0.9950	99.34
4.5	4,373,940	1,765	0.0004	0.9996	98.84
5.5	4,382,810	23	0.0000	1.0000	98.80
6.5	4,388,332	33,079	0.0075	0.9925	98.80
7.5	4,371,740	63,622	0.0146	0.9854	98.06
8.5	4,311,506	815,266	0.1891	0.8109	96.63
9.5	3,496,888	12,677	0.0036	0.9964	78.36
10.5	3,507,149	78,543	0.0224	0.9776	78.08
11.5	3,524,124	124,187	0.0352	0.9648	76.33
12.5	3,439,907	8,332	0.0024	0.9976	73.64
13.5	3,456,966	8,775	0.0025	0.9975	73.46
14.5	3,456,729	2,193	0.0006	0.9994	73.27
15.5	3,472,687	45,389	0.0131	0.9869	73.23
16.5	3,486,610	18,181	0.0052	0.9948	72.27
17.5	3,599,844	148,583	0.0413	0.9587	71.89
18.5	3,751,848	23,089	0.0062	0.9938	68.93
19.5	4,669,518	39,630	0.0085	0.9915	68.50
20.5	5,087,606	143,523	0.0282	0.9718	67.92
21.5	4,993,789	369,338	0.0740	0.9260	66.00
22.5	4,793,345	61,613	0.0129	0.9871	61.12
23.5	4,763,698	131,349	0.0276	0.9724	60.34
24.5	4,722,316	121,598	0.0257	0.9743	58.67
25.5	4,615,708	352,646	0.0764	0.9236	57.16
26.5	4,288,426	28,423	0.0066	0.9934	52.79
27.5	4,295,733	21,964	0.0051	0.9949	52.44
28.5	4,193,176	11,447	0.0027	0.9973	52.18
29.5	4,166,894	673,611	0.1617	0.8383	52.03
30.5	1,136,186	342,855	0.3018	0.6982	43.62
31.5	797,084	220,227	0.2763	0.7237	30.46
32.5	577,775	61,105	0.1058	0.8942	22.04
33.5	521,987	62,036	0.1188	0.8812	19.71
34.5	461,137	29,440	0.0638	0.9362	17.37
35.5	431,800	23,445	0.0543	0.9457	16.26
36.5	408,355	74,388	0.1822	0.8178	15.38
37.5	333,968	11,974	0.0359	0.9641	12.58
38.5	323,879	22,812	0.0704	0.9296	12.13

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

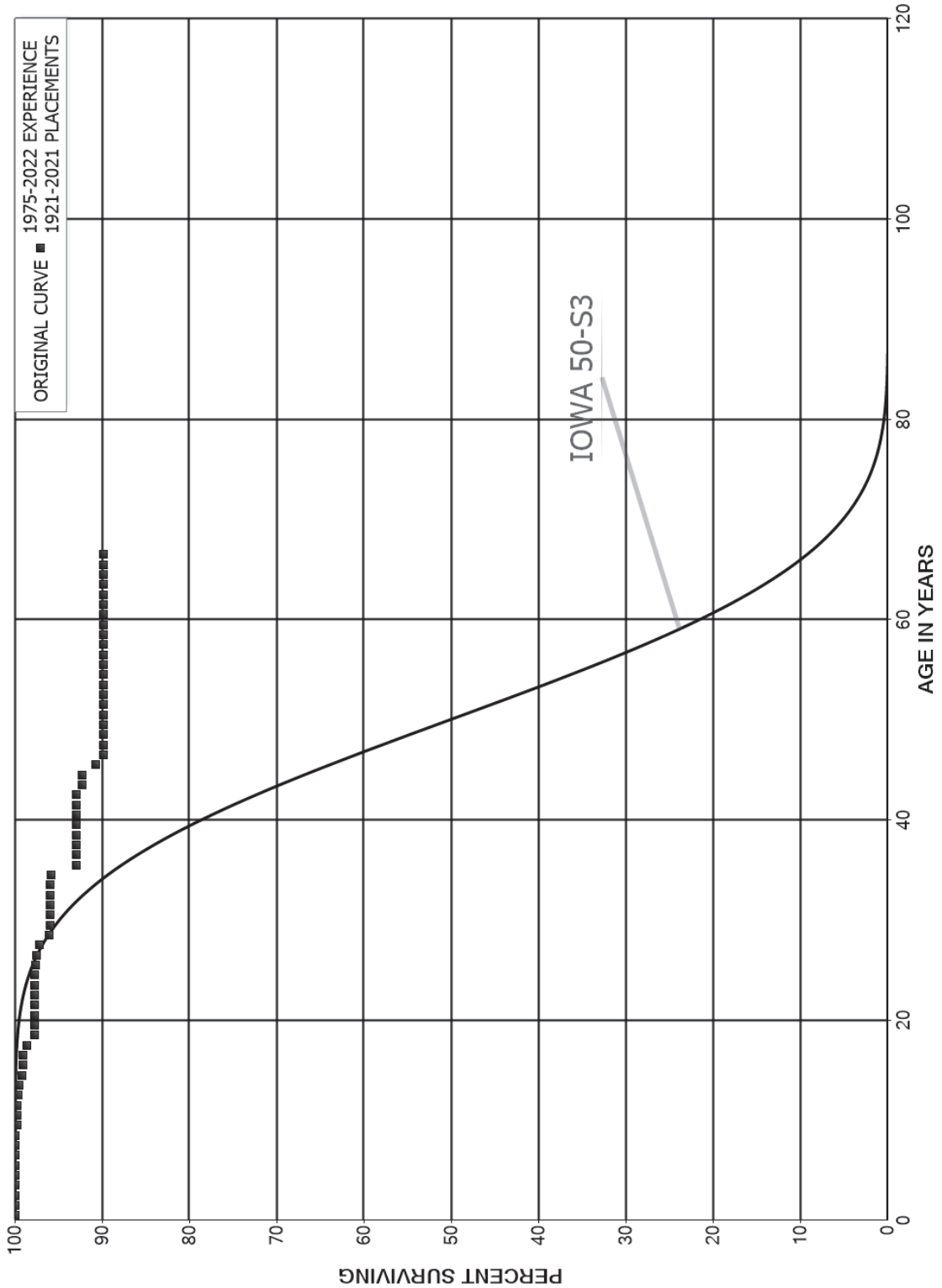
ACCOUNT 307.00 OTHER POWER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1925-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	301,392	36,665	0.1217	0.8783	11.27
40.5	264,931	6,624	0.0250	0.9750	9.90
41.5	233,675	1,345	0.0058	0.9942	9.65
42.5	205,004		0.0000	1.0000	9.60
43.5	199,672	345	0.0017	0.9983	9.60
44.5	144,683	1,439	0.0099	0.9901	9.58
45.5	55,817	1,774	0.0318	0.9682	9.49
46.5	54,043		0.0000	1.0000	9.18
47.5	12,841		0.0000	1.0000	9.18
48.5	23,507		0.0000	1.0000	9.18
49.5	25,191		0.0000	1.0000	9.18
50.5	25,191	1,886	0.0749	0.9251	9.18
51.5	23,306	9,454	0.4057	0.5943	8.50
52.5	13,852	303	0.0219	0.9781	5.05
53.5	13,548	562	0.0415	0.9585	4.94
54.5	12,986		0.0000	1.0000	4.73
55.5	12,986	596	0.0459	0.9541	4.73
56.5	12,390	9,473	0.7646	0.2354	4.52
57.5	2,917		0.0000	1.0000	1.06
58.5	2,917		0.0000	1.0000	1.06
59.5	2,917		0.0000	1.0000	1.06
60.5	2,917	1,536	0.5265	0.4735	1.06
61.5	1,381	1,381	1.0000		0.50
62.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2021 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,375,555		0.0000	1.0000	100.00
0.5	34,427,464		0.0000	1.0000	100.00
1.5	37,215,082		0.0000	1.0000	100.00
2.5	37,692,037		0.0000	1.0000	100.00
3.5	37,676,830	2,639	0.0001	0.9999	100.00
4.5	37,546,787		0.0000	1.0000	99.99
5.5	37,479,058		0.0000	1.0000	99.99
6.5	36,751,619		0.0000	1.0000	99.99
7.5	36,299,849	1,403	0.0000	1.0000	99.99
8.5	36,298,446	108,999	0.0030	0.9970	99.99
9.5	36,189,447	2,366	0.0001	0.9999	99.69
10.5	36,187,081		0.0000	1.0000	99.68
11.5	36,187,081	8,376	0.0002	0.9998	99.68
12.5	36,178,706	38,207	0.0011	0.9989	99.66
13.5	36,160,047	148,868	0.0041	0.9959	99.55
14.5	36,069,814	10,906	0.0003	0.9997	99.14
15.5	36,576,973		0.0000	1.0000	99.11
16.5	36,652,179	196,123	0.0054	0.9946	99.11
17.5	36,513,210	308,027	0.0084	0.9916	98.58
18.5	37,809,491		0.0000	1.0000	97.75
19.5	37,870,724		0.0000	1.0000	97.75
20.5	38,084,098		0.0000	1.0000	97.75
21.5	33,183,355		0.0000	1.0000	97.75
22.5	33,213,097	259	0.0000	1.0000	97.75
23.5	32,364,372		0.0000	1.0000	97.75
24.5	31,232,910	60,618	0.0019	0.9981	97.75
25.5	31,202,609	15,161	0.0005	0.9995	97.56
26.5	31,451,648	94,672	0.0030	0.9970	97.51
27.5	31,399,858	370,443	0.0118	0.9882	97.22
28.5	31,029,415	39,618	0.0013	0.9987	96.07
29.5	30,989,797		0.0000	1.0000	95.95
30.5	11,907,837		0.0000	1.0000	95.95
31.5	11,871,933		0.0000	1.0000	95.95
32.5	11,583,004	2,650	0.0002	0.9998	95.95
33.5	11,461,641	6,889	0.0006	0.9994	95.93
34.5	11,454,752	347,734	0.0304	0.9696	95.87
35.5	11,107,018		0.0000	1.0000	92.96
36.5	10,613,962	1,556	0.0001	0.9999	92.96
37.5	10,158,424		0.0000	1.0000	92.95
38.5	10,158,424		0.0000	1.0000	92.95

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2021 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,844,420		0.0000	1.0000	92.95
40.5	9,571,375		0.0000	1.0000	92.95
41.5	9,326,437		0.0000	1.0000	92.95
42.5	9,150,045	70,120	0.0077	0.9923	92.95
43.5	9,050,304		0.0000	1.0000	92.24
44.5	8,990,914	142,739	0.0159	0.9841	92.24
45.5	8,645,369	84,348	0.0098	0.9902	90.77
46.5	8,404,539		0.0000	1.0000	89.89
47.5	5,417,316		0.0000	1.0000	89.89
48.5	5,304,033		0.0000	1.0000	89.89
49.5	3,297,677		0.0000	1.0000	89.89
50.5	2,892,562		0.0000	1.0000	89.89
51.5	2,869,960		0.0000	1.0000	89.89
52.5	2,858,400		0.0000	1.0000	89.89
53.5	2,881,790		0.0000	1.0000	89.89
54.5	2,881,790		0.0000	1.0000	89.89
55.5	2,881,790		0.0000	1.0000	89.89
56.5	2,881,790		0.0000	1.0000	89.89
57.5	2,881,790		0.0000	1.0000	89.89
58.5	2,881,790		0.0000	1.0000	89.89
59.5	2,881,790		0.0000	1.0000	89.89
60.5	2,881,790		0.0000	1.0000	89.89
61.5	2,862,242		0.0000	1.0000	89.89
62.5	2,807,829		0.0000	1.0000	89.89
63.5	2,293,429		0.0000	1.0000	89.89
64.5	2,218,319		0.0000	1.0000	89.89
65.5	2,218,319		0.0000	1.0000	89.89
66.5	640,612		0.0000	1.0000	89.89
67.5	579,378		0.0000	1.0000	89.89
68.5	385,460		0.0000	1.0000	89.89
69.5	385,460		0.0000	1.0000	89.89
70.5	379,810		0.0000	1.0000	89.89
71.5	379,810		0.0000	1.0000	89.89
72.5	379,810		0.0000	1.0000	89.89
73.5	349,494		0.0000	1.0000	89.89
74.5	86,851		0.0000	1.0000	89.89
75.5	43,968		0.0000	1.0000	89.89
76.5	43,968		0.0000	1.0000	89.89
77.5	43,968		0.0000	1.0000	89.89
78.5	43,968		0.0000	1.0000	89.89

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

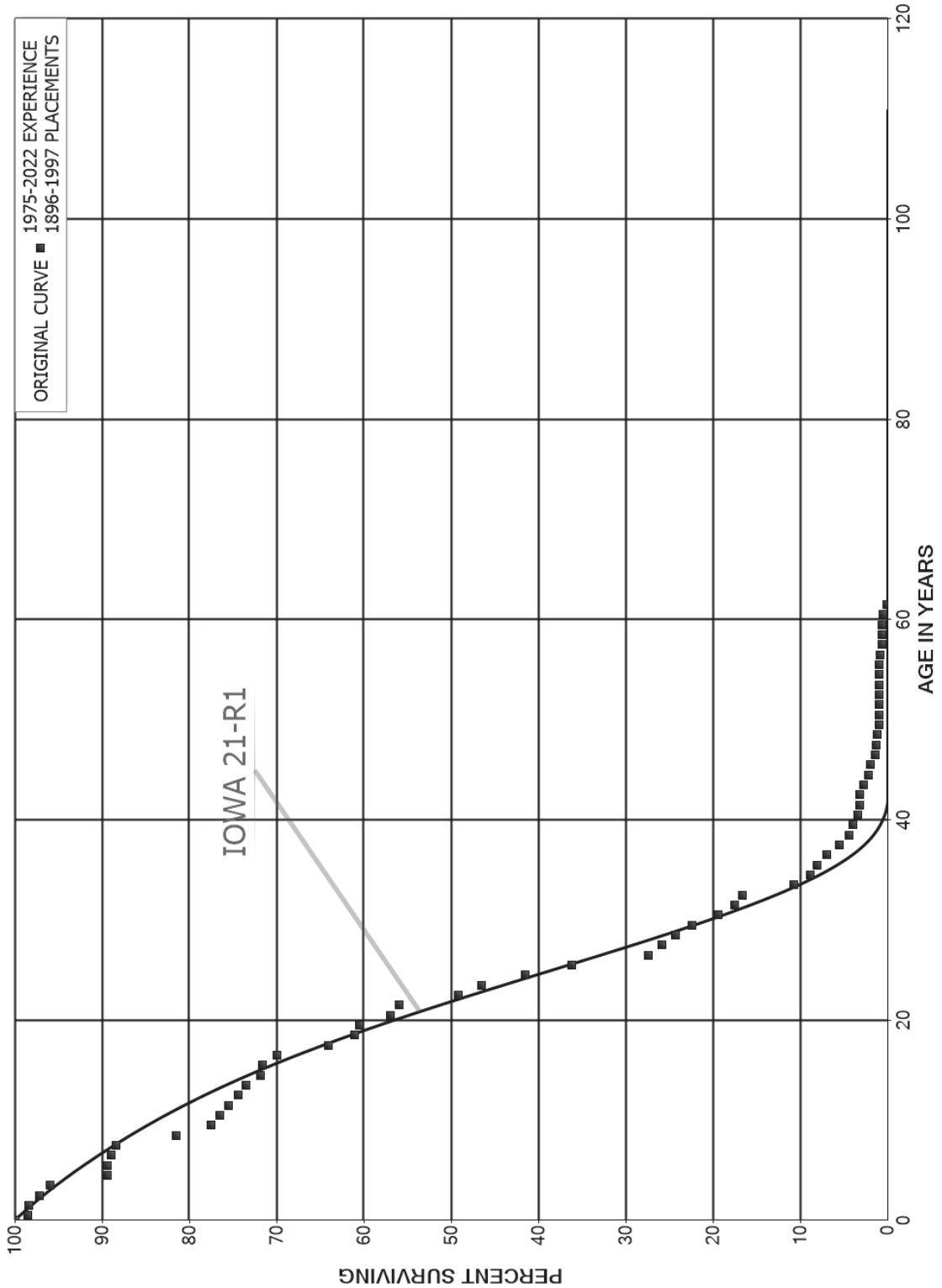
ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2021 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	43,968		0.0000	1.0000	89.89
80.5	23,391		0.0000	1.0000	89.89
81.5	23,391		0.0000	1.0000	89.89
82.5	23,391		0.0000	1.0000	89.89
83.5	23,391		0.0000	1.0000	89.89
84.5	23,391		0.0000	1.0000	89.89
85.5	23,391		0.0000	1.0000	89.89
86.5	23,391		0.0000	1.0000	89.89
87.5	23,391		0.0000	1.0000	89.89
88.5	23,391		0.0000	1.0000	89.89
89.5	23,391		0.0000	1.0000	89.89
90.5	23,391		0.0000	1.0000	89.89
91.5	23,391		0.0000	1.0000	89.89
92.5	23,391		0.0000	1.0000	89.89
93.5	23,391		0.0000	1.0000	89.89
94.5	23,391		0.0000	1.0000	89.89
95.5	23,391		0.0000	1.0000	89.89
96.5	23,391		0.0000	1.0000	89.89
97.5	23,391		0.0000	1.0000	89.89
98.5	23,391		0.0000	1.0000	89.89
99.5	23,391		0.0000	1.0000	89.89
100.5	23,391		0.0000	1.0000	89.89
101.5					89.89

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 320.00 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1896-1997 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,864,286	74,396	0.0153	0.9847	100.00
0.5	8,108,681	2,326	0.0003	0.9997	98.47
1.5	8,216,136	106,800	0.0130	0.9870	98.44
2.5	8,204,260	100,332	0.0122	0.9878	97.16
3.5	8,115,370	552,858	0.0681	0.9319	95.97
4.5	7,652,766	6,461	0.0008	0.9992	89.44
5.5	7,664,067	33,108	0.0043	0.9957	89.36
6.5	7,677,726	45,573	0.0059	0.9941	88.97
7.5	7,691,267	605,649	0.0787	0.9213	88.45
8.5	7,129,015	345,571	0.0485	0.9515	81.48
9.5	6,893,380	93,344	0.0135	0.9865	77.53
10.5	6,962,792	85,892	0.0123	0.9877	76.48
11.5	7,489,872	115,249	0.0154	0.9846	75.54
12.5	8,051,127	97,193	0.0121	0.9879	74.38
13.5	8,476,768	195,334	0.0230	0.9770	73.48
14.5	8,085,483	21,808	0.0027	0.9973	71.79
15.5	6,080,306	142,162	0.0234	0.9766	71.59
16.5	6,094,272	508,240	0.0834	0.9166	69.92
17.5	6,195,261	296,716	0.0479	0.9521	64.09
18.5	6,485,447	50,917	0.0079	0.9921	61.02
19.5	6,791,328	402,733	0.0593	0.9407	60.54
20.5	8,051,255	138,134	0.0172	0.9828	56.95
21.5	8,433,840	1,023,864	0.1214	0.8786	55.97
22.5	7,951,996	431,848	0.0543	0.9457	49.18
23.5	7,779,980	832,685	0.1070	0.8930	46.51
24.5	7,512,957	963,705	0.1283	0.8717	41.53
25.5	6,840,739	1,657,809	0.2423	0.7577	36.20
26.5	5,504,555	320,244	0.0582	0.9418	27.43
27.5	5,341,001	315,325	0.0590	0.9410	25.83
28.5	5,088,792	391,411	0.0769	0.9231	24.31
29.5	4,757,772	640,136	0.1345	0.8655	22.44
30.5	4,159,970	403,505	0.0970	0.9030	19.42
31.5	3,838,844	195,627	0.0510	0.9490	17.54
32.5	3,728,951	1,322,326	0.3546	0.6454	16.64
33.5	2,641,883	469,898	0.1779	0.8221	10.74
34.5	2,215,374	200,307	0.0904	0.9096	8.83
35.5	2,067,343	277,209	0.1341	0.8659	8.03
36.5	1,800,077	366,036	0.2033	0.7967	6.95
37.5	1,442,328	294,213	0.2040	0.7960	5.54
38.5	1,238,113	122,593	0.0990	0.9010	4.41

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1896-1997 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,107,314	147,337	0.1331	0.8669	3.97
40.5	967,716	77,671	0.0803	0.9197	3.44
41.5	906,481	8,747	0.0096	0.9904	3.17
42.5	917,947	121,411	0.1323	0.8677	3.14
43.5	707,315	144,564	0.2044	0.7956	2.72
44.5	664,418	55,996	0.0843	0.9157	2.17
45.5	624,064	180,989	0.2900	0.7100	1.98
46.5	518,163	40,566	0.0783	0.9217	1.41
47.5	626,598	76,750	0.1225	0.8775	1.30
48.5	930,787	111,726	0.1200	0.8800	1.14
49.5	827,191	30,879	0.0373	0.9627	1.00
50.5	815,040	6,016	0.0074	0.9926	0.96
51.5	835,892	5,024	0.0060	0.9940	0.96
52.5	908,950	10,385	0.0114	0.9886	0.95
53.5	913,098	15,377	0.0168	0.9832	0.94
54.5	901,511	19,562	0.0217	0.9783	0.93
55.5	892,552	80,032	0.0897	0.9103	0.91
56.5	819,942	168,302	0.2053	0.7947	0.82
57.5	651,719	54,316	0.0833	0.9167	0.65
58.5	607,667	6,259	0.0103	0.9897	0.60
59.5	602,093	145,986	0.2425	0.7575	0.59
60.5	459,605	378,197	0.8229	0.1771	0.45
61.5	81,408	17,416	0.2139	0.7861	0.08
62.5	63,992	10,171	0.1589	0.8411	0.06
63.5	53,821	20,201	0.3753	0.6247	0.05
64.5	110,937	1,249	0.0113	0.9887	0.03
65.5	109,773	13,514	0.1231	0.8769	0.03
66.5	105,850	847	0.0080	0.9920	0.03
67.5	105,003	6,333	0.0603	0.9397	0.03
68.5	106,496	7,261	0.0682	0.9318	0.03
69.5	121,882	2,518	0.0207	0.9793	0.02
70.5	272,154	301	0.0011	0.9989	0.02
71.5	271,852	9,011	0.0331	0.9669	0.02
72.5	262,841	3,499	0.0133	0.9867	0.02
73.5	259,342	139,798	0.5390	0.4610	0.02
74.5	119,544	45,068	0.3770	0.6230	0.01
75.5	74,476	535	0.0072	0.9928	0.01
76.5	75,326	38,802	0.5151	0.4849	0.01
77.5	36,524	70	0.0019	0.9981	0.00
78.5	38,778		0.0000	1.0000	0.00

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

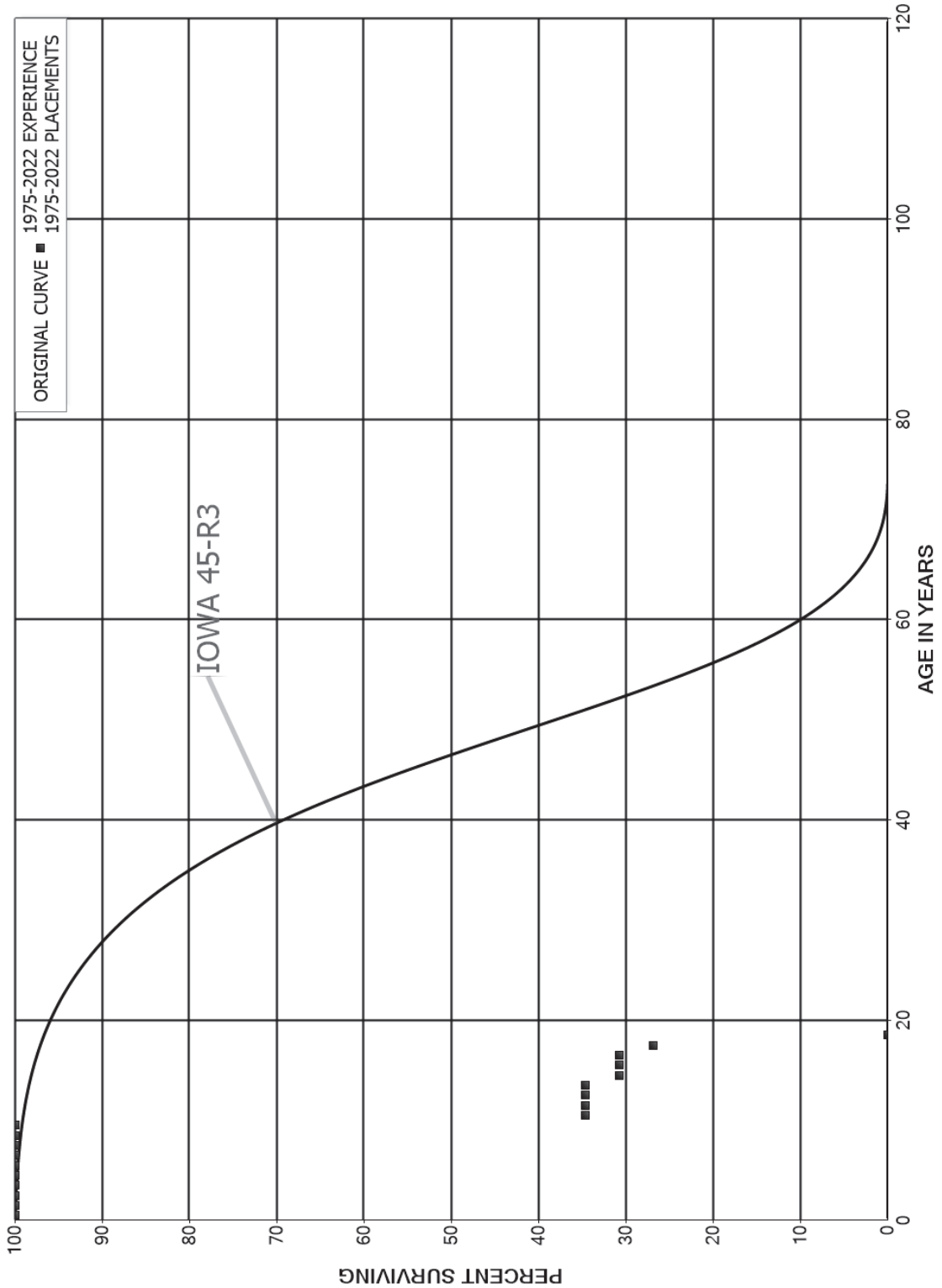
ACCOUNT 320.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1896-1997 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	38,778	24,031	0.6197	0.3803	0.00
80.5	14,746	12,422	0.8424	0.1576	0.00
81.5	2,324	2,324	1.0000		0.00
82.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

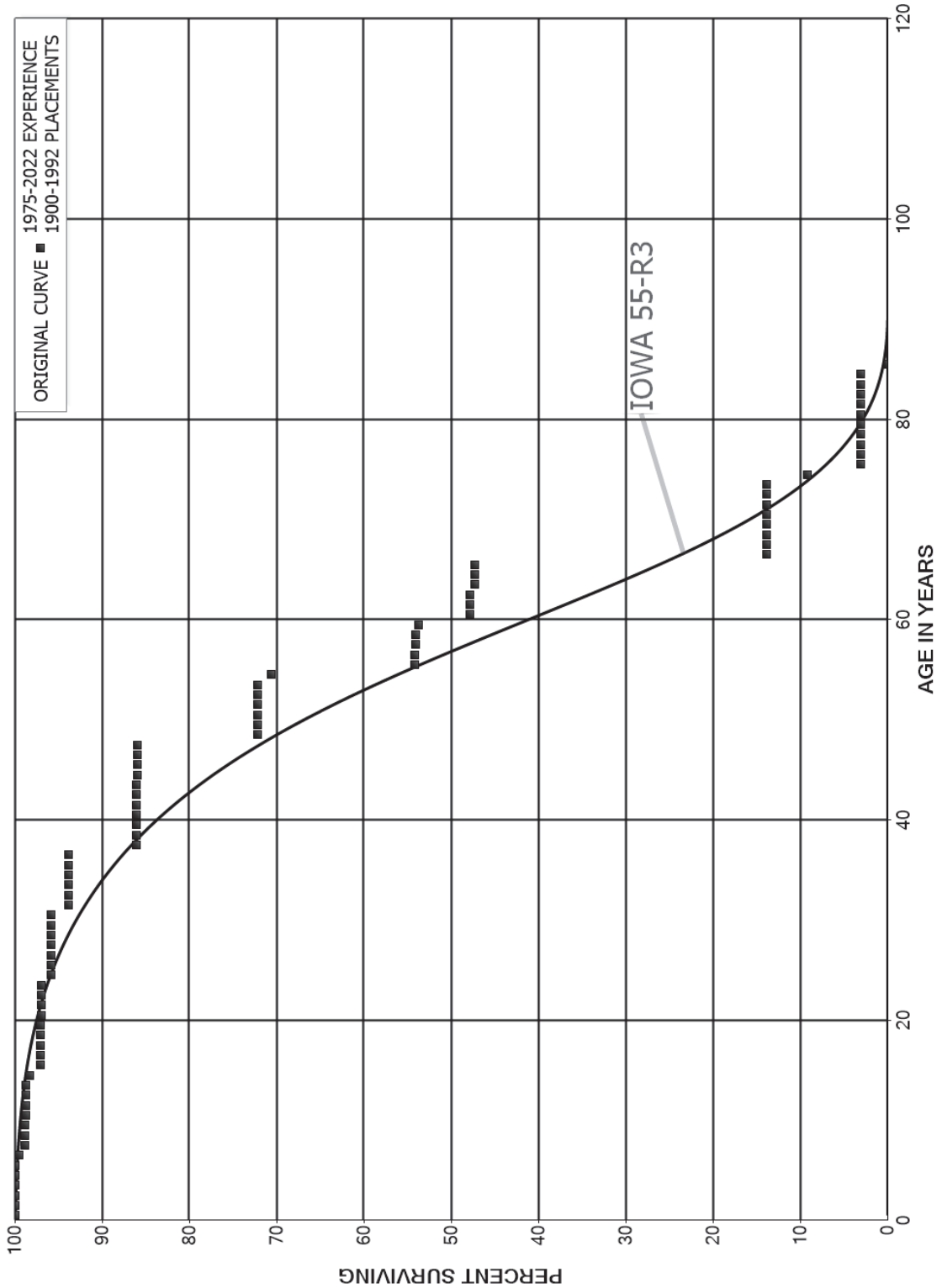
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	550,751		0.0000	1.0000	100.00
0.5	366,930		0.0000	1.0000	100.00
1.5	257,117		0.0000	1.0000	100.00
2.5	257,117		0.0000	1.0000	100.00
3.5	257,117		0.0000	1.0000	100.00
4.5	257,117		0.0000	1.0000	100.00
5.5	257,117		0.0000	1.0000	100.00
6.5	257,117		0.0000	1.0000	100.00
7.5	257,117		0.0000	1.0000	100.00
8.5	257,117		0.0000	1.0000	100.00
9.5	257,117	168,171	0.6541	0.3459	100.00
10.5	88,946		0.0000	1.0000	34.59
11.5	88,946		0.0000	1.0000	34.59
12.5	88,946		0.0000	1.0000	34.59
13.5	88,946	9,894	0.1112	0.8888	34.59
14.5	79,052		0.0000	1.0000	30.75
15.5	79,052		0.0000	1.0000	30.75
16.5	79,052	10,097	0.1277	0.8723	30.75
17.5	68,954	68,954	1.0000		26.82
18.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 362.00 GAS HOLDERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-1992 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,368,679		0.0000	1.0000	100.00
0.5	5,072,239		0.0000	1.0000	100.00
1.5	5,075,584		0.0000	1.0000	100.00
2.5	5,097,400	1,445	0.0003	0.9997	100.00
3.5	5,152,807		0.0000	1.0000	99.97
4.5	5,221,097	3,345	0.0006	0.9994	99.97
5.5	5,217,753	21,817	0.0042	0.9958	99.91
6.5	5,195,936	36,094	0.0069	0.9931	99.49
7.5	5,159,842		0.0000	1.0000	98.80
8.5	5,160,072		0.0000	1.0000	98.80
9.5	5,160,472	2,995	0.0006	0.9994	98.80
10.5	5,157,477	1,316	0.0003	0.9997	98.74
11.5	5,156,161		0.0000	1.0000	98.72
12.5	5,156,161		0.0000	1.0000	98.72
13.5	5,156,161	20,759	0.0040	0.9960	98.72
14.5	5,135,402	68,290	0.0133	0.9867	98.32
15.5	5,067,113		0.0000	1.0000	97.01
16.5	5,068,761		0.0000	1.0000	97.01
17.5	5,071,197		0.0000	1.0000	97.01
18.5	5,072,554		0.0000	1.0000	97.01
19.5	5,072,554	1,648	0.0003	0.9997	97.01
20.5	5,696,991		0.0000	1.0000	96.98
21.5	5,696,999		0.0000	1.0000	96.98
22.5	5,697,155		0.0000	1.0000	96.98
23.5	5,697,155	66,126	0.0116	0.9884	96.98
24.5	5,631,029	230	0.0000	1.0000	95.85
25.5	5,630,799	400	0.0001	0.9999	95.85
26.5	5,630,399		0.0000	1.0000	95.84
27.5	5,633,729	2,076	0.0004	0.9996	95.84
28.5	5,631,653	360	0.0001	0.9999	95.81
29.5	5,631,292		0.0000	1.0000	95.80
30.5	5,524,391	111,845	0.0202	0.9798	95.80
31.5	5,423,210	1,154	0.0002	0.9998	93.86
32.5	5,422,954		0.0000	1.0000	93.84
33.5	5,422,954		0.0000	1.0000	93.84
34.5	5,422,954	1,357	0.0003	0.9997	93.84
35.5	5,421,870		0.0000	1.0000	93.82
36.5	5,421,870	446,960	0.0824	0.9176	93.82
37.5	4,999,514	8	0.0000	1.0000	86.08
38.5	5,017,117	156	0.0000	1.0000	86.08

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-1992 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,910,817		0.0000	1.0000	86.08
40.5	4,911,549		0.0000	1.0000	86.08
41.5	4,767,139		0.0000	1.0000	86.08
42.5	4,772,374	898	0.0002	0.9998	86.08
43.5	4,771,476	3,330	0.0007	0.9993	86.07
44.5	4,768,146		0.0000	1.0000	86.01
45.5	4,768,146		0.0000	1.0000	86.01
46.5	4,758,608	4,276	0.0009	0.9991	86.01
47.5	66,630	10,663	0.1600	0.8400	85.93
48.5	152,006		0.0000	1.0000	72.18
49.5	917,566		0.0000	1.0000	72.18
50.5	917,566		0.0000	1.0000	72.18
51.5	1,166,684	273	0.0002	0.9998	72.18
52.5	1,166,411		0.0000	1.0000	72.16
53.5	1,166,411	24,605	0.0211	0.9789	72.16
54.5	1,141,806	266,729	0.2336	0.7664	70.64
55.5	875,077		0.0000	1.0000	54.14
56.5	875,077	732	0.0008	0.9992	54.14
57.5	874,345		0.0000	1.0000	54.09
58.5	874,345	5,235	0.0060	0.9940	54.09
59.5	869,110	96,039	0.1105	0.8895	53.77
60.5	773,071		0.0000	1.0000	47.83
61.5	774,531		0.0000	1.0000	47.83
62.5	774,531	7,911	0.0102	0.9898	47.83
63.5	767,379		0.0000	1.0000	47.34
64.5	1,082,466		0.0000	1.0000	47.34
65.5	1,082,466	765,160	0.7069	0.2931	47.34
66.5	317,306		0.0000	1.0000	13.88
67.5	317,306		0.0000	1.0000	13.88
68.5	317,306		0.0000	1.0000	13.88
69.5	317,306		0.0000	1.0000	13.88
70.5	475,445		0.0000	1.0000	13.88
71.5	475,445	1,460	0.0031	0.9969	13.88
72.5	473,985		0.0000	1.0000	13.83
73.5	473,985	158,897	0.3352	0.6648	13.83
74.5	469,130	315,087	0.6716	0.3284	9.20
75.5	154,043		0.0000	1.0000	3.02
76.5	154,043		0.0000	1.0000	3.02
77.5	154,043		0.0000	1.0000	3.02
78.5	154,043		0.0000	1.0000	3.02

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

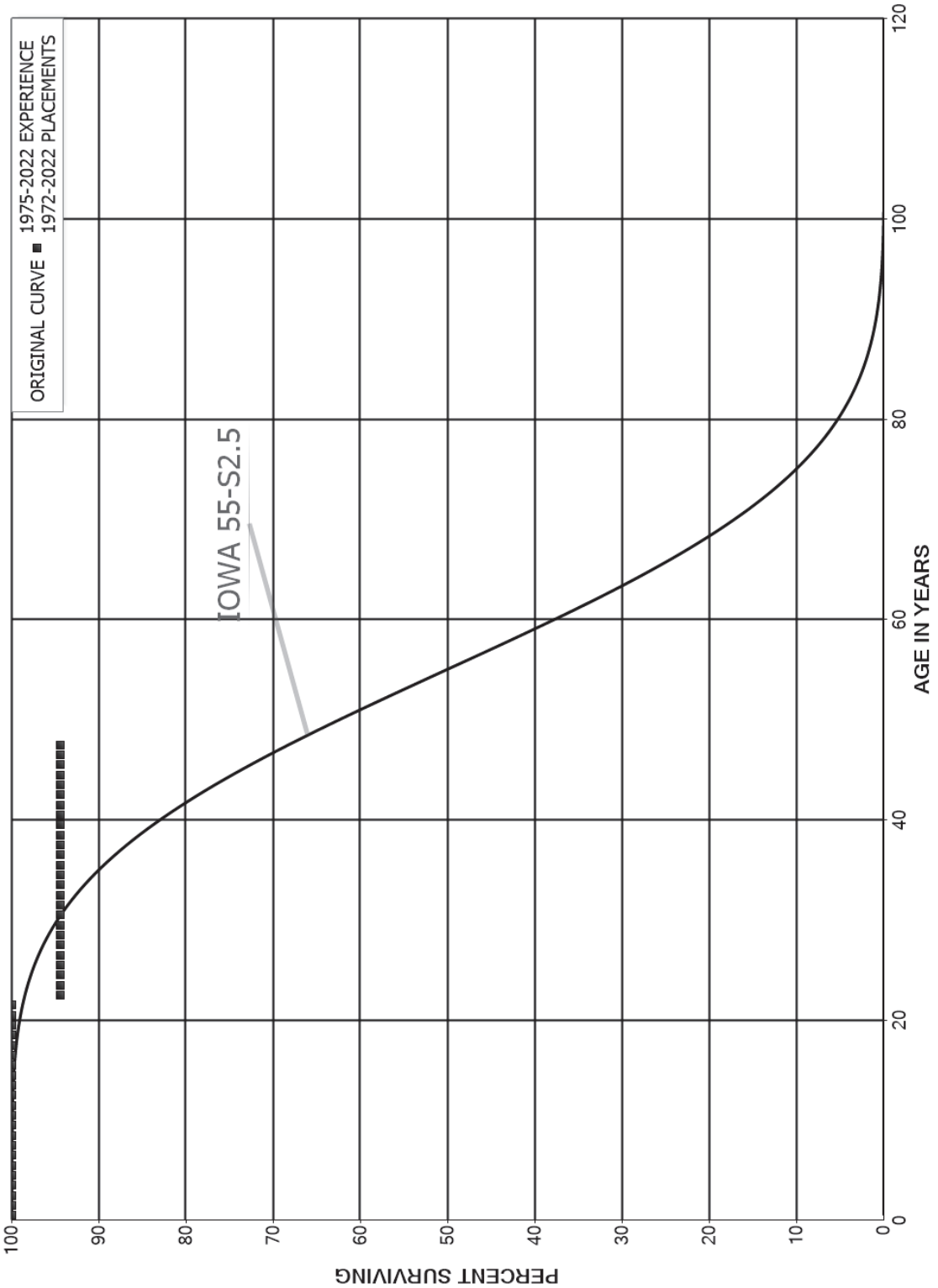
ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-1992 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	154,043		0.0000	1.0000	3.02
80.5	154,043		0.0000	1.0000	3.02
81.5	154,043		0.0000	1.0000	3.02
82.5	154,043		0.0000	1.0000	3.02
83.5	154,043		0.0000	1.0000	3.02
84.5	154,043	154,043	1.0000		3.02
85.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNTS 363.20 AND 363.40 OTHER STORAGE PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 363.20 AND 363.40 OTHER STORAGE PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,087,347		0.0000	1.0000	100.00
0.5	14,257,292		0.0000	1.0000	100.00
1.5	6,315,571		0.0000	1.0000	100.00
2.5	6,416,714		0.0000	1.0000	100.00
3.5	5,794,152		0.0000	1.0000	100.00
4.5	4,922,596		0.0000	1.0000	100.00
5.5	4,119,571		0.0000	1.0000	100.00
6.5	3,300,827		0.0000	1.0000	100.00
7.5	2,949,147		0.0000	1.0000	100.00
8.5	2,949,147		0.0000	1.0000	100.00
9.5	2,353,283		0.0000	1.0000	100.00
10.5	1,905,322		0.0000	1.0000	100.00
11.5	1,905,322		0.0000	1.0000	100.00
12.5	1,905,322		0.0000	1.0000	100.00
13.5	1,905,322		0.0000	1.0000	100.00
14.5	1,905,322		0.0000	1.0000	100.00
15.5	1,793,807		0.0000	1.0000	100.00
16.5	1,793,807		0.0000	1.0000	100.00
17.5	1,793,807		0.0000	1.0000	100.00
18.5	1,793,807		0.0000	1.0000	100.00
19.5	1,793,807		0.0000	1.0000	100.00
20.5	1,793,807		0.0000	1.0000	100.00
21.5	1,793,807	101,143	0.0564	0.9436	100.00
22.5	1,692,663		0.0000	1.0000	94.36
23.5	1,656,143		0.0000	1.0000	94.36
24.5	1,656,143		0.0000	1.0000	94.36
25.5	1,608,136		0.0000	1.0000	94.36
26.5	1,588,916		0.0000	1.0000	94.36
27.5	1,588,916		0.0000	1.0000	94.36
28.5	1,588,916		0.0000	1.0000	94.36
29.5	1,565,767		0.0000	1.0000	94.36
30.5	1,339,028		0.0000	1.0000	94.36
31.5	1,339,028		0.0000	1.0000	94.36
32.5	1,339,028		0.0000	1.0000	94.36
33.5	1,184,391		0.0000	1.0000	94.36
34.5	1,184,391		0.0000	1.0000	94.36
35.5	1,184,391		0.0000	1.0000	94.36
36.5	1,184,391		0.0000	1.0000	94.36
37.5	1,184,391		0.0000	1.0000	94.36
38.5	1,184,391		0.0000	1.0000	94.36

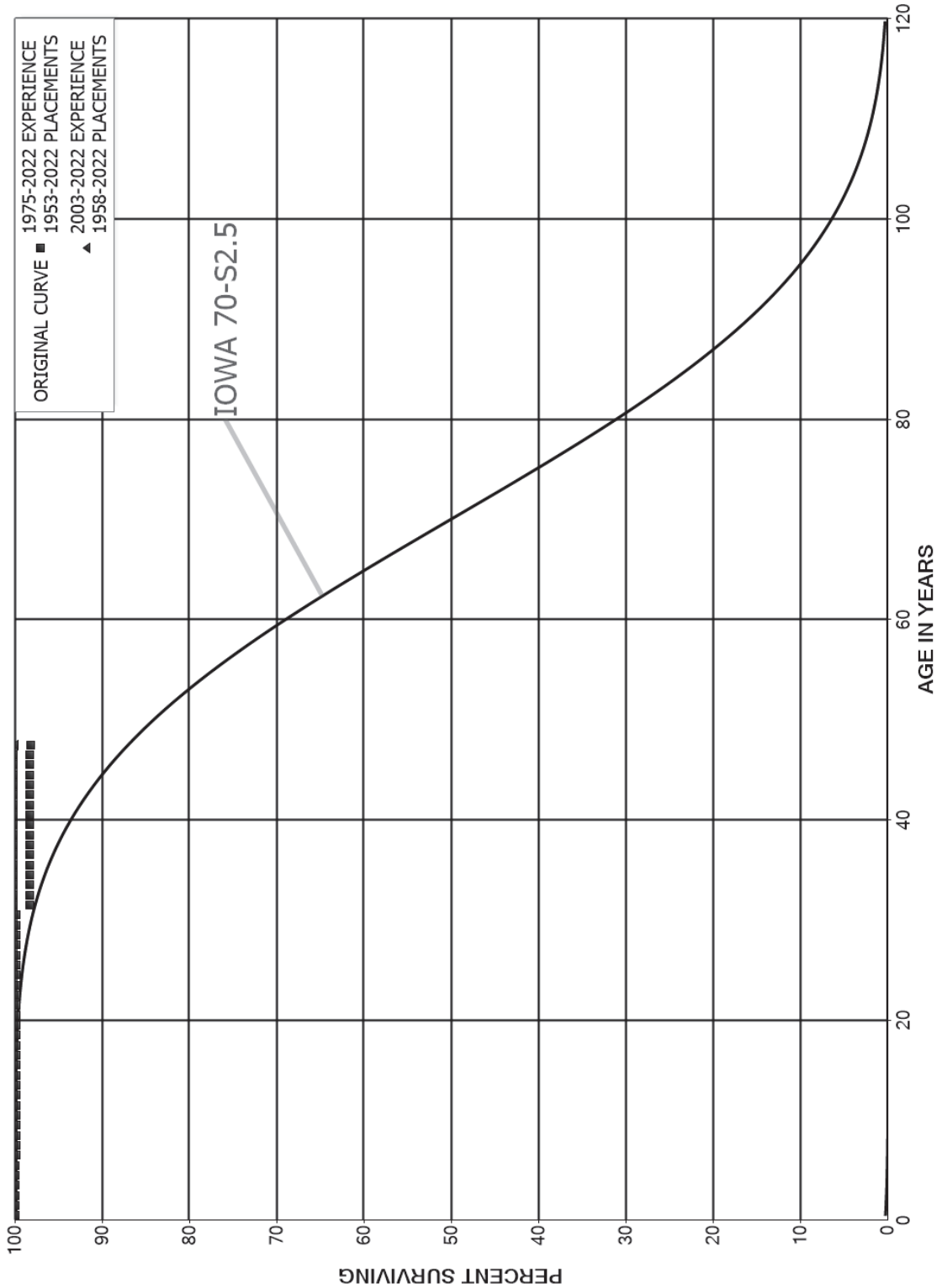
PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 363.20 AND 363.40 OTHER STORAGE PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1972-2022			EXPERIENCE BAND 1975-2022		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,184,391		0.0000	1.0000	94.36
40.5	1,184,391		0.0000	1.0000	94.36
41.5	1,184,391		0.0000	1.0000	94.36
42.5	1,184,391		0.0000	1.0000	94.36
43.5	1,184,391		0.0000	1.0000	94.36
44.5	1,184,391		0.0000	1.0000	94.36
45.5	1,184,391		0.0000	1.0000	94.36
46.5	719,609		0.0000	1.0000	94.36
47.5					94.36

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 367.00 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 367.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1953-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	65,733,812		0.0000	1.0000	100.00
0.5	80,365,318		0.0000	1.0000	100.00
1.5	93,874,260	102,473	0.0011	0.9989	100.00
2.5	93,239,288		0.0000	1.0000	99.89
3.5	91,511,987		0.0000	1.0000	99.89
4.5	88,991,309		0.0000	1.0000	99.89
5.5	80,067,393	5,810	0.0001	0.9999	99.89
6.5	80,061,582		0.0000	1.0000	99.88
7.5	79,209,323		0.0000	1.0000	99.88
8.5	79,209,323		0.0000	1.0000	99.88
9.5	79,209,323		0.0000	1.0000	99.88
10.5	79,102,031		0.0000	1.0000	99.88
11.5	79,100,018		0.0000	1.0000	99.88
12.5	79,046,634		0.0000	1.0000	99.88
13.5	78,573,761		0.0000	1.0000	99.88
14.5	78,493,528		0.0000	1.0000	99.88
15.5	78,465,807		0.0000	1.0000	99.88
16.5	72,871,044	22,365	0.0003	0.9997	99.88
17.5	59,045,269		0.0000	1.0000	99.85
18.5	59,045,269		0.0000	1.0000	99.85
19.5	59,045,269		0.0000	1.0000	99.85
20.5	58,906,320		0.0000	1.0000	99.85
21.5	54,349,092		0.0000	1.0000	99.85
22.5	54,349,092		0.0000	1.0000	99.85
23.5	54,204,057		0.0000	1.0000	99.85
24.5	52,377,186		0.0000	1.0000	99.85
25.5	52,377,186		0.0000	1.0000	99.85
26.5	50,317,187		0.0000	1.0000	99.85
27.5	47,604,608		0.0000	1.0000	99.85
28.5	47,479,106		0.0000	1.0000	99.85
29.5	44,663,940		0.0000	1.0000	99.85
30.5	34,057,324	524,493	0.0154	0.9846	99.85
31.5	28,184,917		0.0000	1.0000	98.32
32.5	28,184,917		0.0000	1.0000	98.32
33.5	27,523,025		0.0000	1.0000	98.32
34.5	20,164,767		0.0000	1.0000	98.32
35.5	20,044,186		0.0000	1.0000	98.32
36.5	19,749,873		0.0000	1.0000	98.32
37.5	18,718,642		0.0000	1.0000	98.32
38.5	18,701,030		0.0000	1.0000	98.32

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 367.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1953-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,328,866		0.0000	1.0000	98.32
40.5	18,287,821		0.0000	1.0000	98.32
41.5	18,282,328		0.0000	1.0000	98.32
42.5	18,265,819		0.0000	1.0000	98.32
43.5	18,265,819		0.0000	1.0000	98.32
44.5	17,981,933		0.0000	1.0000	98.32
45.5	16,376,612		0.0000	1.0000	98.32
46.5	14,492,661	21,451	0.0015	0.9985	98.32
47.5	13,046		0.0000	1.0000	98.17
48.5	13,046		0.0000	1.0000	98.17
49.5	13,046		0.0000	1.0000	98.17
50.5	13,046		0.0000	1.0000	98.17
51.5	13,046		0.0000	1.0000	98.17
52.5	13,046		0.0000	1.0000	98.17
53.5	13,046		0.0000	1.0000	98.17
54.5	13,046		0.0000	1.0000	98.17
55.5	13,046		0.0000	1.0000	98.17
56.5	13,046		0.0000	1.0000	98.17
57.5	13,046		0.0000	1.0000	98.17
58.5	13,046		0.0000	1.0000	98.17
59.5	6,876		0.0000	1.0000	98.17
60.5	6,876		0.0000	1.0000	98.17
61.5	6,876		0.0000	1.0000	98.17
62.5	6,876		0.0000	1.0000	98.17
63.5	6,876		0.0000	1.0000	98.17
64.5					98.17

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 367.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,616,157		0.0000	1.0000	100.00
0.5	21,755,104		0.0000	1.0000	100.00
1.5	39,953,511		0.0000	1.0000	100.00
2.5	39,421,011		0.0000	1.0000	100.00
3.5	37,838,745		0.0000	1.0000	100.00
4.5	37,144,938		0.0000	1.0000	100.00
5.5	28,221,021		0.0000	1.0000	100.00
6.5	30,281,021		0.0000	1.0000	100.00
7.5	32,141,341		0.0000	1.0000	100.00
8.5	32,266,842		0.0000	1.0000	100.00
9.5	35,104,373		0.0000	1.0000	100.00
10.5	45,603,697		0.0000	1.0000	100.00
11.5	50,921,977		0.0000	1.0000	100.00
12.5	50,868,593		0.0000	1.0000	100.00
13.5	51,057,613		0.0000	1.0000	100.00
14.5	58,335,637		0.0000	1.0000	100.00
15.5	58,428,497		0.0000	1.0000	100.00
16.5	53,121,171	22,365	0.0004	0.9996	100.00
17.5	40,326,627		0.0000	1.0000	99.96
18.5	40,344,238		0.0000	1.0000	99.96
19.5	40,716,403		0.0000	1.0000	99.96
20.5	40,618,498		0.0000	1.0000	99.96
21.5	35,542,270		0.0000	1.0000	99.96
22.5	35,558,780		0.0000	1.0000	99.96
23.5	35,413,745		0.0000	1.0000	99.96
24.5	33,870,760		0.0000	1.0000	99.96
25.5	35,476,081		0.0000	1.0000	99.96
26.5	35,300,033		0.0000	1.0000	99.96
27.5	47,045,617		0.0000	1.0000	99.96
28.5	46,920,115		0.0000	1.0000	99.96
29.5	44,104,950		0.0000	1.0000	99.96
30.5	33,498,333		0.0000	1.0000	99.96
31.5	28,150,420		0.0000	1.0000	99.96
32.5	28,150,420		0.0000	1.0000	99.96
33.5	27,488,528		0.0000	1.0000	99.96
34.5	20,130,270		0.0000	1.0000	99.96
35.5	20,009,689		0.0000	1.0000	99.96
36.5	19,715,376		0.0000	1.0000	99.96
37.5	18,684,145		0.0000	1.0000	99.96
38.5	18,666,533		0.0000	1.0000	99.96

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

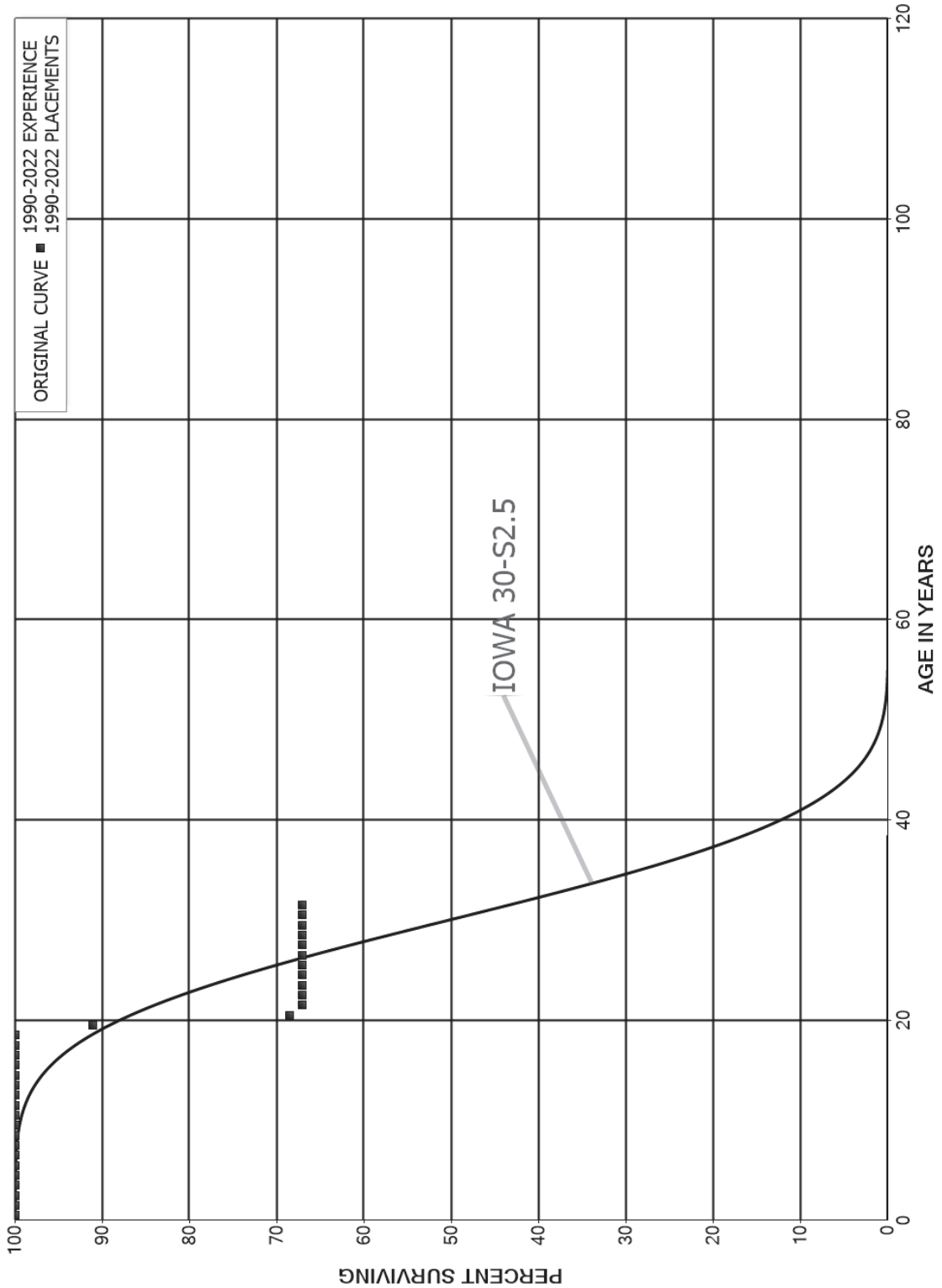
ACCOUNT 367.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1958-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,321,990		0.0000	1.0000	99.96
40.5	18,280,945		0.0000	1.0000	99.96
41.5	18,275,452		0.0000	1.0000	99.96
42.5	18,258,942		0.0000	1.0000	99.96
43.5	18,258,942		0.0000	1.0000	99.96
44.5	17,981,933		0.0000	1.0000	99.96
45.5	16,376,612		0.0000	1.0000	99.96
46.5	14,492,661	21,451	0.0015	0.9985	99.96
47.5	13,046		0.0000	1.0000	99.81
48.5	13,046		0.0000	1.0000	99.81
49.5	13,046		0.0000	1.0000	99.81
50.5	13,046		0.0000	1.0000	99.81
51.5	13,046		0.0000	1.0000	99.81
52.5	13,046		0.0000	1.0000	99.81
53.5	13,046		0.0000	1.0000	99.81
54.5	13,046		0.0000	1.0000	99.81
55.5	13,046		0.0000	1.0000	99.81
56.5	13,046		0.0000	1.0000	99.81
57.5	13,046		0.0000	1.0000	99.81
58.5	13,046		0.0000	1.0000	99.81
59.5	6,876		0.0000	1.0000	99.81
60.5	6,876		0.0000	1.0000	99.81
61.5	6,876		0.0000	1.0000	99.81
62.5	6,876		0.0000	1.0000	99.81
63.5	6,876		0.0000	1.0000	99.81
64.5					99.81

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

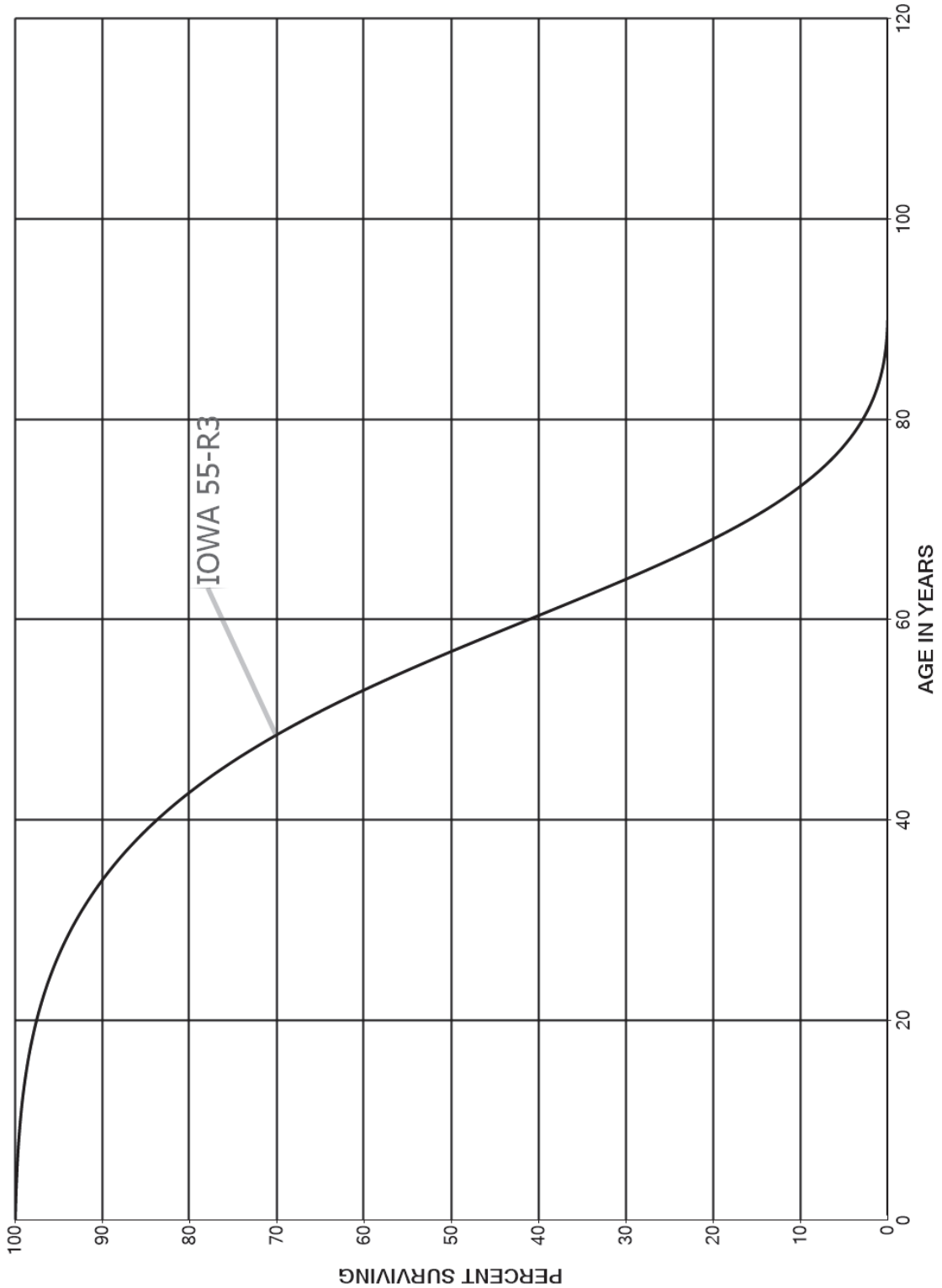
ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

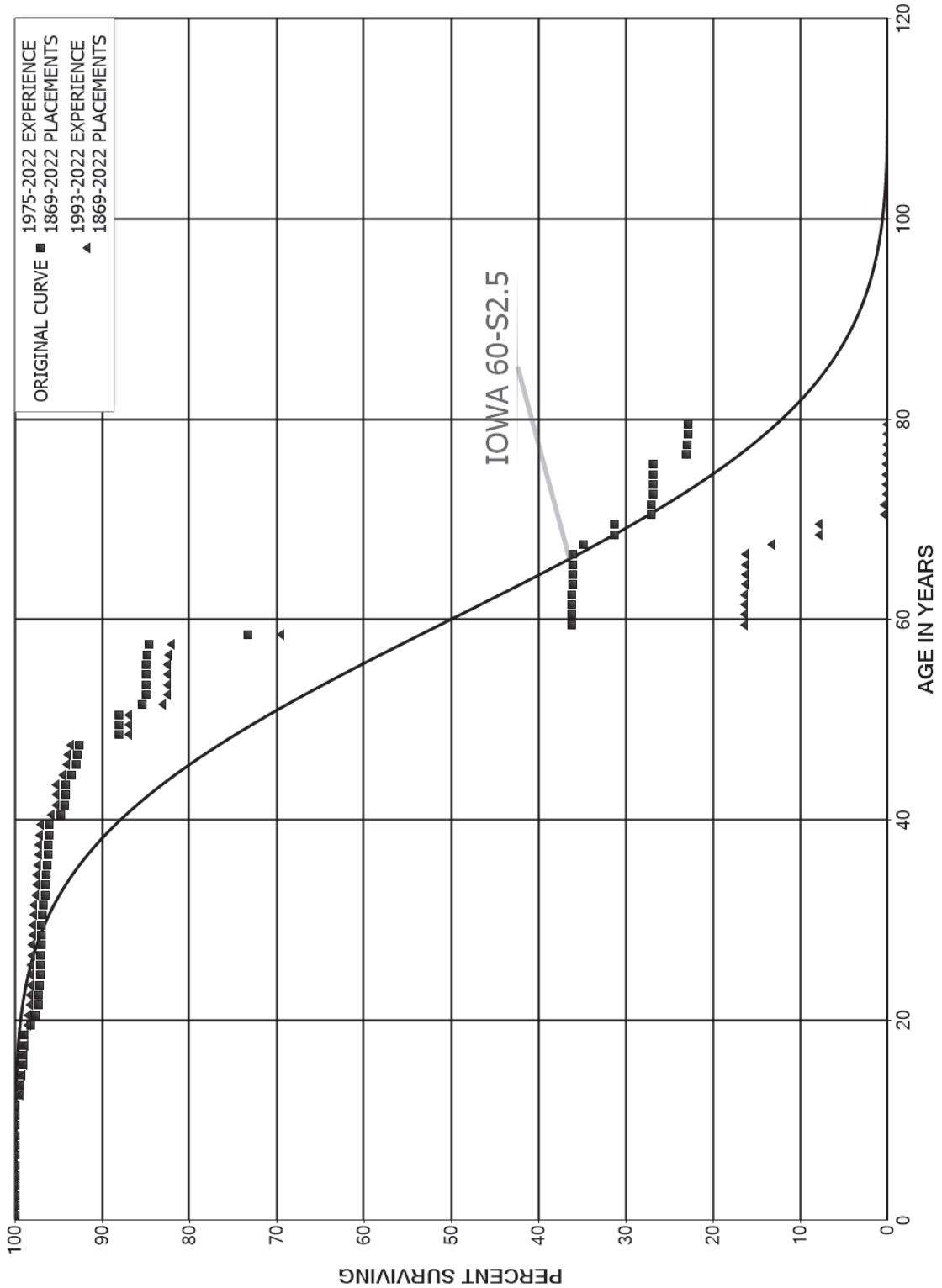
PLACEMENT BAND 1990-2022 EXPERIENCE BAND 1990-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,410,358		0.0000	1.0000	100.00
0.5	6,411,488		0.0000	1.0000	100.00
1.5	6,299,196		0.0000	1.0000	100.00
2.5	6,299,196		0.0000	1.0000	100.00
3.5	6,299,196		0.0000	1.0000	100.00
4.5	6,299,196		0.0000	1.0000	100.00
5.5	6,299,196		0.0000	1.0000	100.00
6.5	6,299,196		0.0000	1.0000	100.00
7.5	6,299,196		0.0000	1.0000	100.00
8.5	6,299,196		0.0000	1.0000	100.00
9.5	6,299,196		0.0000	1.0000	100.00
10.5	6,299,196		0.0000	1.0000	100.00
11.5	6,299,196		0.0000	1.0000	100.00
12.5	6,299,196		0.0000	1.0000	100.00
13.5	6,299,196		0.0000	1.0000	100.00
14.5	6,299,196		0.0000	1.0000	100.00
15.5	6,299,196		0.0000	1.0000	100.00
16.5	6,299,196		0.0000	1.0000	100.00
17.5	6,299,196		0.0000	1.0000	100.00
18.5	6,299,196	560,850	0.0890	0.9110	100.00
19.5	5,738,346	1,420,174	0.2475	0.7525	91.10
20.5	4,318,172	94,052	0.0218	0.9782	68.55
21.5	4,224,120		0.0000	1.0000	67.06
22.5	4,224,120		0.0000	1.0000	67.06
23.5	4,224,120		0.0000	1.0000	67.06
24.5	4,224,120		0.0000	1.0000	67.06
25.5	4,146,914		0.0000	1.0000	67.06
26.5	4,132,689		0.0000	1.0000	67.06
27.5	4,131,835		0.0000	1.0000	67.06
28.5	4,131,826		0.0000	1.0000	67.06
29.5	3,484,937		0.0000	1.0000	67.06
30.5	3,059,964		0.0000	1.0000	67.06
31.5	1,139		0.0000	1.0000	67.06
32.5					67.06

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 374.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY
SMOOTH SURVIVOR CURVE



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	101,393,309		0.0000	1.0000	100.00
0.5	101,075,615	64,248	0.0006	0.9994	100.00
1.5	96,414,875		0.0000	1.0000	99.94
2.5	95,852,979		0.0000	1.0000	99.94
3.5	96,547,518		0.0000	1.0000	99.94
4.5	55,560,298	10,350	0.0002	0.9998	99.94
5.5	47,749,583		0.0000	1.0000	99.92
6.5	47,818,310		0.0000	1.0000	99.92
7.5	47,853,974		0.0000	1.0000	99.92
8.5	48,152,337		0.0000	1.0000	99.92
9.5	48,162,455		0.0000	1.0000	99.92
10.5	48,515,749	10,841	0.0002	0.9998	99.92
11.5	48,514,157	202,314	0.0042	0.9958	99.90
12.5	48,311,139	38,168	0.0008	0.9992	99.48
13.5	48,376,927	58,702	0.0012	0.9988	99.40
14.5	48,322,709	77,761	0.0016	0.9984	99.28
15.5	48,247,334	20,589	0.0004	0.9996	99.12
16.5	47,543,975	12,547	0.0003	0.9997	99.08
17.5	47,566,124	40,538	0.0009	0.9991	99.05
18.5	47,529,933	368,246	0.0077	0.9923	98.97
19.5	46,099,109	266,216	0.0058	0.9942	98.20
20.5	45,929,602	165,076	0.0036	0.9964	97.63
21.5	45,817,617	4,587	0.0001	0.9999	97.28
22.5	45,837,995	64,815	0.0014	0.9986	97.27
23.5	45,155,018	23,761	0.0005	0.9995	97.14
24.5	42,633,482	5,879	0.0001	0.9999	97.08
25.5	40,500,656	11,823	0.0003	0.9997	97.07
26.5	40,078,234	20,821	0.0005	0.9995	97.04
27.5	39,353,574	36,882	0.0009	0.9991	96.99
28.5	38,530,304	593	0.0000	1.0000	96.90
29.5	35,234,647	39,848	0.0011	0.9989	96.90
30.5	28,494,081	3,650	0.0001	0.9999	96.79
31.5	25,974,064	66,722	0.0026	0.9974	96.78
32.5	25,292,248	16,283	0.0006	0.9994	96.53
33.5	21,866,161	21,690	0.0010	0.9990	96.47
34.5	21,392,181	22,117	0.0010	0.9990	96.37
35.5	20,926,258	9,314	0.0004	0.9996	96.27
36.5	20,075,657	4,441	0.0002	0.9998	96.23
37.5	19,391,806	34,255	0.0018	0.9982	96.21
38.5	18,797,210	5,153	0.0003	0.9997	96.04

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,456,132	189,718	0.0131	0.9869	96.01
40.5	13,470,975	69,059	0.0051	0.9949	94.75
41.5	13,087,277	4,982	0.0004	0.9996	94.27
42.5	12,601,510		0.0000	1.0000	94.23
43.5	12,276,480	95,515	0.0078	0.9922	94.23
44.5	8,644,407	45,623	0.0053	0.9947	93.50
45.5	8,111,050	11,685	0.0014	0.9986	93.00
46.5	6,862,060	18,816	0.0027	0.9973	92.87
47.5	383,938	18,826	0.0490	0.9510	92.61
48.5	365,610	15	0.0000	1.0000	88.07
49.5	376,135		0.0000	1.0000	88.07
50.5	376,135	11,480	0.0305	0.9695	88.07
51.5	364,655	1,695	0.0046	0.9954	85.38
52.5	348,674		0.0000	1.0000	84.98
53.5	348,903		0.0000	1.0000	84.98
54.5	304,681		0.0000	1.0000	84.98
55.5	304,681	415	0.0014	0.9986	84.98
56.5	245,800	853	0.0035	0.9965	84.87
57.5	255,751	34,019	0.1330	0.8670	84.57
58.5	116,362	58,926	0.5064	0.4936	73.32
59.5	57,436		0.0000	1.0000	36.19
60.5	57,436		0.0000	1.0000	36.19
61.5	57,436		0.0000	1.0000	36.19
62.5	76,267	227	0.0030	0.9970	36.19
63.5	76,569		0.0000	1.0000	36.09
64.5	82,206		0.0000	1.0000	36.09
65.5	64,366		0.0000	1.0000	36.09
66.5	64,366	2,232	0.0347	0.9653	36.09
67.5	81,448	8,426	0.1035	0.8965	34.83
68.5	84,899		0.0000	1.0000	31.23
69.5	85,804	11,470	0.1337	0.8663	31.23
70.5	74,611		0.0000	1.0000	27.06
71.5	74,611	499	0.0067	0.9933	27.06
72.5	74,113		0.0000	1.0000	26.87
73.5	74,113		0.0000	1.0000	26.87
74.5	74,113		0.0000	1.0000	26.87
75.5	76,218	10,804	0.1417	0.8583	26.87
76.5	65,414	228	0.0035	0.9965	23.07
77.5	74,208	595	0.0080	0.9920	22.98
78.5	73,613		0.0000	1.0000	22.80

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	74,837		0.0000	1.0000	22.80
80.5	74,837	3,000	0.0401	0.9599	22.80
81.5	71,837	5,115	0.0712	0.9288	21.89
82.5	66,722	5,638	0.0845	0.9155	20.33
83.5	61,085		0.0000	1.0000	18.61
84.5	61,085		0.0000	1.0000	18.61
85.5	61,085	18,831	0.3083	0.6917	18.61
86.5	42,254	529	0.0125	0.9875	12.87
87.5	41,782		0.0000	1.0000	12.71
88.5	41,782		0.0000	1.0000	12.71
89.5	41,782		0.0000	1.0000	12.71
90.5	41,782	19,314	0.4622	0.5378	12.71
91.5	22,469	11,878	0.5286	0.4714	6.84
92.5	10,591	905	0.0854	0.9146	3.22
93.5	9,686	277	0.0286	0.9714	2.95
94.5	9,408		0.0000	1.0000	2.86
95.5	9,408		0.0000	1.0000	2.86
96.5	9,408		0.0000	1.0000	2.86
97.5	9,408		0.0000	1.0000	2.86
98.5	9,408	2,105	0.2237	0.7763	2.86
99.5	7,303		0.0000	1.0000	2.22
100.5	7,303	6,022	0.8245	0.1755	2.22
101.5	1,281		0.0000	1.0000	0.39
102.5	1,281	1,224	0.9552	0.0448	0.39
103.5	57		0.0000	1.0000	0.02
104.5	35,984		0.0000	1.0000	0.02
105.5	37,634		0.0000	1.0000	0.02
106.5	37,634		0.0000	1.0000	0.02
107.5	37,634		0.0000	1.0000	0.02
108.5	37,634		0.0000	1.0000	0.02
109.5	37,634		0.0000	1.0000	0.02
110.5	37,634	57	0.0015	0.9985	0.02
111.5	37,577		0.0000	1.0000	0.02
112.5	37,577		0.0000	1.0000	0.02
113.5	37,577		0.0000	1.0000	0.02
114.5	37,577		0.0000	1.0000	0.02
115.5	37,577		0.0000	1.0000	0.02
116.5	37,577		0.0000	1.0000	0.02
117.5	37,577		0.0000	1.0000	0.02
118.5	37,577		0.0000	1.0000	0.02

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,577		0.0000	1.0000	0.02
120.5	37,577		0.0000	1.0000	0.02
121.5	37,577		0.0000	1.0000	0.02
122.5	37,577		0.0000	1.0000	0.02
123.5	37,577		0.0000	1.0000	0.02
124.5	37,577		0.0000	1.0000	0.02
125.5	37,577		0.0000	1.0000	0.02
126.5	37,577		0.0000	1.0000	0.02
127.5	37,577	35,927	0.9561	0.0439	0.02
128.5	1,650	1,650	1.0000		0.00
129.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	68,272,231		0.0000	1.0000	100.00
0.5	72,812,377	64,248	0.0009	0.9991	100.00
1.5	70,695,016		0.0000	1.0000	99.91
2.5	70,734,795		0.0000	1.0000	99.91
3.5	73,972,765		0.0000	1.0000	99.91
4.5	33,444,757		0.0000	1.0000	99.91
5.5	26,133,689		0.0000	1.0000	99.91
6.5	27,039,633		0.0000	1.0000	99.91
7.5	27,728,450		0.0000	1.0000	99.91
8.5	28,371,751		0.0000	1.0000	99.91
9.5	32,784,640		0.0000	1.0000	99.91
10.5	33,885,476	10,841	0.0003	0.9997	99.91
11.5	34,216,155	202,314	0.0059	0.9941	99.88
12.5	34,506,793	29,472	0.0009	0.9991	99.29
13.5	34,862,399	56,874	0.0016	0.9984	99.20
14.5	38,493,693	77,761	0.0020	0.9980	99.04
15.5	38,952,315	20,217	0.0005	0.9995	98.84
16.5	39,986,800	4,649	0.0001	0.9999	98.79
17.5	46,499,693	38,900	0.0008	0.9992	98.78
18.5	46,472,352	128,332	0.0028	0.9972	98.70
19.5	45,239,067	30,975	0.0007	0.9993	98.42
20.5	45,233,405	61,399	0.0014	0.9986	98.36
21.5	45,183,974	4,463	0.0001	0.9999	98.22
22.5	45,196,083	64,815	0.0014	0.9986	98.21
23.5	44,505,850	18,980	0.0004	0.9996	98.07
24.5	42,007,770	2,820	0.0001	0.9999	98.03
25.5	39,910,824	10,846	0.0003	0.9997	98.02
26.5	39,550,095	20,821	0.0005	0.9995	98.00
27.5	38,818,064	36,882	0.0010	0.9990	97.95
28.5	38,110,373	593	0.0000	1.0000	97.85
29.5	34,818,002	39,848	0.0011	0.9989	97.85
30.5	28,092,209	3,258	0.0001	0.9999	97.74
31.5	25,573,200	66,722	0.0026	0.9974	97.73
32.5	24,882,700	16,283	0.0007	0.9993	97.47
33.5	21,458,427	10,064	0.0005	0.9995	97.41
34.5	21,006,403	22,117	0.0011	0.9989	97.36
35.5	20,503,648	9,314	0.0005	0.9995	97.26
36.5	19,656,329	4,441	0.0002	0.9998	97.22
37.5	19,021,767	34,255	0.0018	0.9982	97.20
38.5	18,523,880	5,153	0.0003	0.9997	97.02

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,235,665	189,518	0.0133	0.9867	96.99
40.5	13,275,282	69,059	0.0052	0.9948	95.70
41.5	12,912,276	3,062	0.0002	0.9998	95.20
42.5	12,475,206		0.0000	1.0000	95.18
43.5	12,148,960	95,515	0.0079	0.9921	95.18
44.5	8,508,460	45,438	0.0053	0.9947	94.43
45.5	7,992,776	11,685	0.0015	0.9985	93.93
46.5	6,742,856	18,816	0.0028	0.9972	93.79
47.5	264,734	18,826	0.0711	0.9289	93.53
48.5	245,908	15	0.0001	0.9999	86.88
49.5	245,893		0.0000	1.0000	86.87
50.5	257,788	11,480	0.0445	0.9555	86.87
51.5	248,856	1,695	0.0068	0.9932	83.00
52.5	266,894		0.0000	1.0000	82.44
53.5	325,820		0.0000	1.0000	82.44
54.5	281,004		0.0000	1.0000	82.44
55.5	281,004	415	0.0015	0.9985	82.44
56.5	222,123	853	0.0038	0.9962	82.32
57.5	221,497	34,019	0.1536	0.8464	82.00
58.5	76,993	58,926	0.7653	0.2347	69.41
59.5	18,068		0.0000	1.0000	16.29
60.5	18,068		0.0000	1.0000	16.29
61.5	20,300		0.0000	1.0000	16.29
62.5	28,726	227	0.0079	0.9921	16.29
63.5	28,498		0.0000	1.0000	16.16
64.5	29,429		0.0000	1.0000	16.16
65.5	11,588		0.0000	1.0000	16.16
66.5	12,087	2,232	0.1847	0.8153	16.16
67.5	20,395	8,426	0.4131	0.5869	13.17
68.5	11,969		0.0000	1.0000	7.73
69.5	11,969	11,470	0.9584	0.0416	7.73
70.5	499		0.0000	1.0000	0.32
71.5	727	499	0.6857	0.3143	0.32
72.5	823		0.0000	1.0000	0.10
73.5	823		0.0000	1.0000	0.10
74.5	823		0.0000	1.0000	0.10
75.5	11,627	10,804	0.9292	0.0708	0.10
76.5	5,938	228	0.0385	0.9615	0.01
77.5	5,709	595	0.1042	0.8958	0.01
78.5	5,115		0.0000	1.0000	0.01

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	5,115		0.0000	1.0000	0.01
80.5	23,946		0.0000	1.0000	0.01
81.5	24,474	5,115	0.2090	0.7910	0.01
82.5	24,997	5,638	0.2255	0.7745	0.00
83.5	19,360		0.0000	1.0000	0.00
84.5	19,360		0.0000	1.0000	0.00
85.5	38,673	18,831	0.4869	0.5131	0.00
86.5	31,720	529	0.0167	0.9833	0.00
87.5	32,096		0.0000	1.0000	0.00
88.5	32,374		0.0000	1.0000	0.00
89.5	32,374		0.0000	1.0000	0.00
90.5	32,374	19,314	0.5966	0.4034	0.00
91.5	13,060	11,878	0.9095	0.0905	0.00
92.5	1,182	905	0.7653	0.2347	0.00
93.5	2,382	277	0.1165	0.8835	0.00
94.5	2,105		0.0000	1.0000	0.00
95.5	8,127		0.0000	1.0000	0.00
96.5	8,127		0.0000	1.0000	0.00
97.5	9,351		0.0000	1.0000	0.00
98.5	9,351	2,105	0.2251	0.7749	0.00
99.5	7,246		0.0000	1.0000	0.00
100.5	7,246	6,022	0.8311	0.1689	0.00
101.5	1,224		0.0000	1.0000	0.00
102.5	1,224	1,224	1.0000		0.00
103.5					
104.5					
105.5	57		0.0000		
106.5	57		0.0000		
107.5	57		0.0000		
108.5	57		0.0000		
109.5	57		0.0000		
110.5	57	57	1.0000		
111.5					
112.5					
113.5					
114.5					
115.5					
116.5					
117.5					
118.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

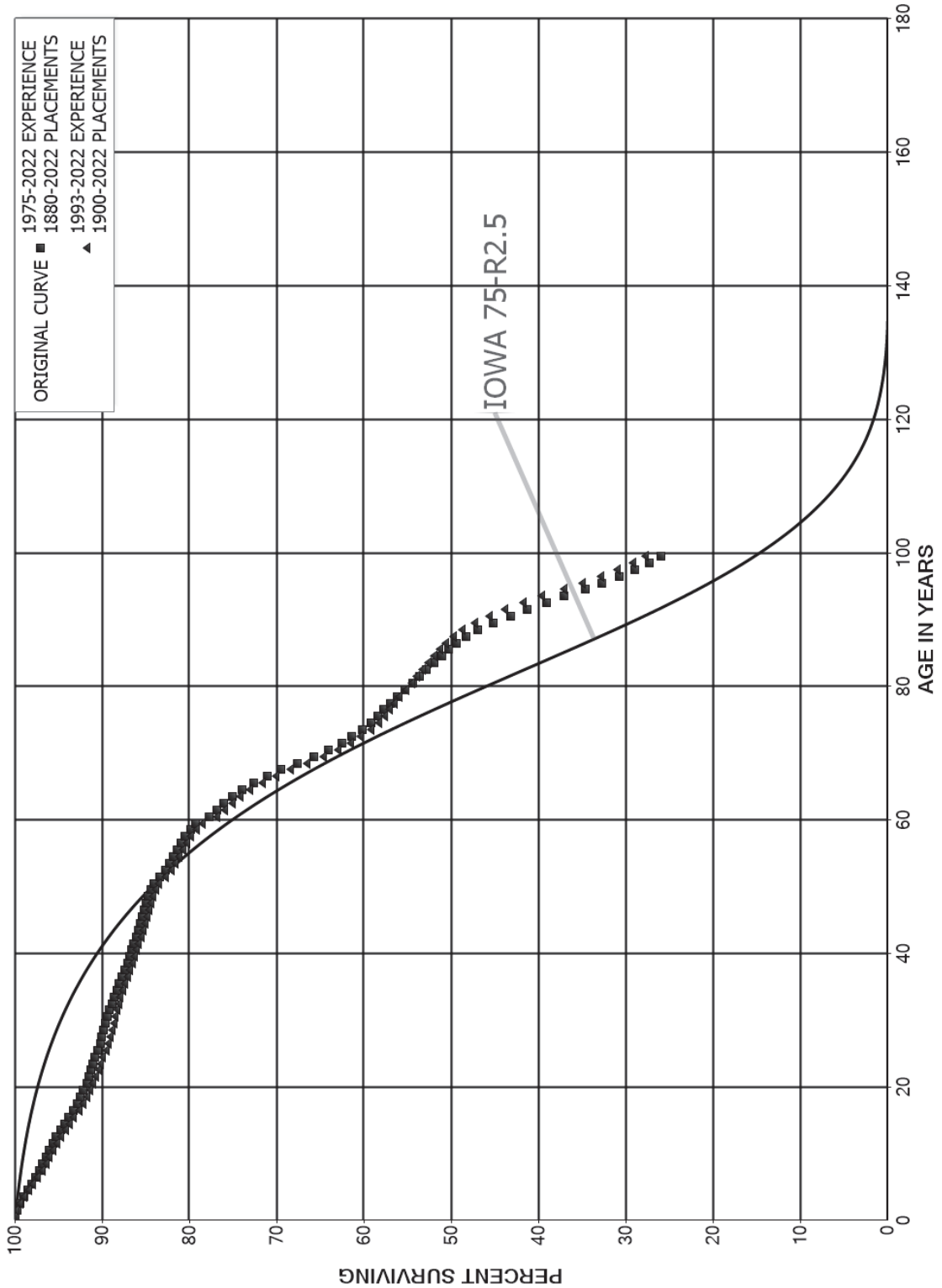
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1869-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5					
120.5					
121.5					
122.5	35,927		0.0000		
123.5	37,577		0.0000		
124.5	37,577		0.0000		
125.5	37,577		0.0000		
126.5	37,577		0.0000		
127.5	37,577	35,927	0.9561		
128.5	1,650	1,650	1.0000		
129.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 376.00 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1880-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,714,396,586	1,147,412	0.0003	0.9997	100.00
0.5	3,527,644,437	8,525,532	0.0024	0.9976	99.97
1.5	3,316,596,396	10,795,674	0.0033	0.9967	99.73
2.5	3,049,005,362	13,031,537	0.0043	0.9957	99.40
3.5	2,850,806,998	12,622,947	0.0044	0.9956	98.98
4.5	2,679,591,798	12,084,073	0.0045	0.9955	98.54
5.5	2,498,979,606	11,501,260	0.0046	0.9954	98.10
6.5	2,396,053,787	10,700,308	0.0045	0.9955	97.64
7.5	2,320,819,796	10,070,110	0.0043	0.9957	97.21
8.5	2,273,523,572	8,165,392	0.0036	0.9964	96.79
9.5	2,216,580,111	8,809,510	0.0040	0.9960	96.44
10.5	2,138,538,131	9,209,928	0.0043	0.9957	96.06
11.5	2,061,847,371	8,133,334	0.0039	0.9961	95.64
12.5	1,909,069,895	10,049,514	0.0053	0.9947	95.26
13.5	1,802,369,767	9,491,780	0.0053	0.9947	94.76
14.5	1,711,395,792	8,333,651	0.0049	0.9951	94.26
15.5	1,646,750,604	9,688,532	0.0059	0.9941	93.80
16.5	1,567,571,695	6,708,167	0.0043	0.9957	93.25
17.5	1,488,004,063	6,274,979	0.0042	0.9958	92.85
18.5	1,427,859,603	5,134,794	0.0036	0.9964	92.46
19.5	1,375,633,566	5,253,165	0.0038	0.9962	92.13
20.5	1,329,723,079	4,026,040	0.0030	0.9970	91.78
21.5	1,284,865,759	3,536,437	0.0028	0.9972	91.50
22.5	1,226,566,626	2,703,773	0.0022	0.9978	91.25
23.5	1,172,654,470	2,418,276	0.0021	0.9979	91.05
24.5	1,130,622,167	4,658,492	0.0041	0.9959	90.86
25.5	1,084,675,188	3,216,656	0.0030	0.9970	90.48
26.5	1,047,100,674	2,208,319	0.0021	0.9979	90.22
27.5	996,918,691	1,804,708	0.0018	0.9982	90.03
28.5	946,284,672	2,243,779	0.0024	0.9976	89.86
29.5	890,232,269	2,224,824	0.0025	0.9975	89.65
30.5	843,410,954	2,736,983	0.0032	0.9968	89.43
31.5	793,204,838	2,233,775	0.0028	0.9972	89.14
32.5	740,113,606	2,475,430	0.0033	0.9967	88.88
33.5	691,362,594	2,083,297	0.0030	0.9970	88.59
34.5	636,878,711	2,167,232	0.0034	0.9966	88.32
35.5	584,846,100	1,894,673	0.0032	0.9968	88.02
36.5	536,382,183	1,893,228	0.0035	0.9965	87.74
37.5	495,051,820	1,751,815	0.0035	0.9965	87.43
38.5	462,924,751	1,295,884	0.0028	0.9972	87.12

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1880-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	433,106,604	1,187,104	0.0027	0.9973	86.87
40.5	406,327,307	1,138,969	0.0028	0.9972	86.63
41.5	381,009,289	1,218,912	0.0032	0.9968	86.39
42.5	357,005,570	1,132,274	0.0032	0.9968	86.11
43.5	336,979,074	1,032,868	0.0031	0.9969	85.84
44.5	324,905,125	739,627	0.0023	0.9977	85.58
45.5	317,150,696	741,021	0.0023	0.9977	85.38
46.5	311,120,160	738,311	0.0024	0.9976	85.18
47.5	306,212,813	755,467	0.0025	0.9975	84.98
48.5	299,332,118	1,362,911	0.0046	0.9954	84.77
49.5	289,268,785	1,231,192	0.0043	0.9957	84.39
50.5	278,896,692	2,195,776	0.0079	0.9921	84.03
51.5	267,812,625	2,053,112	0.0077	0.9923	83.37
52.5	254,967,936	1,382,504	0.0054	0.9946	82.73
53.5	241,921,272	1,420,026	0.0059	0.9941	82.28
54.5	227,656,235	1,168,791	0.0051	0.9949	81.80
55.5	216,974,638	1,081,430	0.0050	0.9950	81.38
56.5	206,407,553	1,160,913	0.0056	0.9944	80.97
57.5	195,886,880	1,537,327	0.0078	0.9922	80.51
58.5	184,849,270	1,506,452	0.0081	0.9919	79.88
59.5	173,196,615	3,227,077	0.0186	0.9814	79.23
60.5	160,366,222	1,815,623	0.0113	0.9887	77.75
61.5	150,032,194	1,677,852	0.0112	0.9888	76.87
62.5	139,275,531	1,717,180	0.0123	0.9877	76.01
63.5	129,417,831	1,893,359	0.0146	0.9854	75.08
64.5	119,640,680	2,143,996	0.0179	0.9821	73.98
65.5	109,196,402	2,353,716	0.0216	0.9784	72.65
66.5	97,513,025	2,240,246	0.0230	0.9770	71.09
67.5	86,877,720	2,317,563	0.0267	0.9733	69.45
68.5	65,891,068	1,784,424	0.0271	0.9729	67.60
69.5	50,260,592	1,342,391	0.0267	0.9733	65.77
70.5	41,693,090	962,058	0.0231	0.9769	64.01
71.5	35,294,908	637,035	0.0180	0.9820	62.54
72.5	33,240,234	657,831	0.0198	0.9802	61.41
73.5	29,726,763	495,596	0.0167	0.9833	60.19
74.5	25,569,045	353,732	0.0138	0.9862	59.19
75.5	23,113,902	265,499	0.0115	0.9885	58.37
76.5	22,234,686	266,237	0.0120	0.9880	57.70
77.5	21,775,154	305,737	0.0140	0.9860	57.01
78.5	21,281,108	351,435	0.0165	0.9835	56.21

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1880-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	20,535,982	323,334	0.0157	0.9843	55.28
80.5	19,816,827	308,005	0.0155	0.9845	54.41
81.5	18,836,216	275,256	0.0146	0.9854	53.56
82.5	17,788,077	284,825	0.0160	0.9840	52.78
83.5	16,909,118	269,160	0.0159	0.9841	51.94
84.5	16,194,155	246,662	0.0152	0.9848	51.11
85.5	15,610,230	287,223	0.0184	0.9816	50.33
86.5	15,067,960	341,815	0.0227	0.9773	49.41
87.5	14,592,777	409,435	0.0281	0.9719	48.28
88.5	13,989,676	510,568	0.0365	0.9635	46.93
89.5	13,358,727	596,964	0.0447	0.9553	45.22
90.5	12,472,788	567,796	0.0455	0.9545	43.20
91.5	11,373,683	601,152	0.0529	0.9471	41.23
92.5	10,072,141	518,416	0.0515	0.9485	39.05
93.5	8,467,318	546,231	0.0645	0.9355	37.04
94.5	6,746,113	376,070	0.0557	0.9443	34.65
95.5	5,043,855	309,100	0.0613	0.9387	32.72
96.5	3,377,737	194,569	0.0576	0.9424	30.71
97.5	1,931,466	113,326	0.0587	0.9413	28.95
98.5	581,251	28,918	0.0498	0.9502	27.25
99.5					25.89

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,111,808,680	1,078,866	0.0003	0.9997	100.00
0.5	2,961,650,953	8,253,854	0.0028	0.9972	99.97
1.5	2,787,525,583	10,657,291	0.0038	0.9962	99.69
2.5	2,560,776,230	12,808,571	0.0050	0.9950	99.31
3.5	2,400,676,313	12,450,171	0.0052	0.9948	98.81
4.5	2,272,912,760	11,877,933	0.0052	0.9948	98.30
5.5	2,132,028,912	11,363,182	0.0053	0.9947	97.78
6.5	2,062,957,661	10,593,127	0.0051	0.9949	97.26
7.5	2,028,123,197	9,976,406	0.0049	0.9951	96.76
8.5	2,001,731,362	8,015,341	0.0040	0.9960	96.29
9.5	1,963,677,051	8,709,511	0.0044	0.9956	95.90
10.5	1,901,884,047	9,013,190	0.0047	0.9953	95.48
11.5	1,839,571,790	7,996,031	0.0043	0.9957	95.02
12.5	1,700,624,068	8,920,969	0.0052	0.9948	94.61
13.5	1,607,317,334	8,790,440	0.0055	0.9945	94.11
14.5	1,519,208,810	7,675,915	0.0051	0.9949	93.60
15.5	1,455,034,403	9,137,569	0.0063	0.9937	93.13
16.5	1,374,444,480	6,468,679	0.0047	0.9953	92.54
17.5	1,291,675,330	6,119,762	0.0047	0.9953	92.11
18.5	1,228,593,902	5,031,273	0.0041	0.9959	91.67
19.5	1,177,931,956	5,015,960	0.0043	0.9957	91.29
20.5	1,120,851,408	3,850,275	0.0034	0.9966	90.91
21.5	1,064,962,766	3,419,024	0.0032	0.9968	90.59
22.5	1,008,230,419	2,567,004	0.0025	0.9975	90.30
23.5	959,109,166	2,246,313	0.0023	0.9977	90.07
24.5	918,894,839	4,362,177	0.0047	0.9953	89.86
25.5	879,118,928	3,053,466	0.0035	0.9965	89.43
26.5	846,050,902	1,958,872	0.0023	0.9977	89.12
27.5	803,552,522	1,550,115	0.0019	0.9981	88.92
28.5	762,630,096	1,841,584	0.0024	0.9976	88.75
29.5	717,826,115	1,342,725	0.0019	0.9981	88.53
30.5	682,083,992	1,558,412	0.0023	0.9977	88.37
31.5	641,862,798	1,303,720	0.0020	0.9980	88.16
32.5	599,760,185	1,344,627	0.0022	0.9978	87.99
33.5	560,595,833	1,537,835	0.0027	0.9973	87.79
34.5	514,724,392	1,600,604	0.0031	0.9969	87.55
35.5	471,921,164	1,471,749	0.0031	0.9969	87.27
36.5	434,256,695	1,491,615	0.0034	0.9966	87.00
37.5	403,287,535	1,241,468	0.0031	0.9969	86.70
38.5	393,410,997	1,139,230	0.0029	0.9971	86.44

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	382,288,668	1,031,797	0.0027	0.9973	86.19
40.5	365,329,273	1,022,530	0.0028	0.9972	85.95
41.5	347,579,337	1,124,486	0.0032	0.9968	85.71
42.5	335,217,170	1,063,740	0.0032	0.9968	85.44
43.5	318,757,699	898,465	0.0028	0.9972	85.16
44.5	311,235,113	709,376	0.0023	0.9977	84.92
45.5	304,656,211	725,165	0.0024	0.9976	84.73
46.5	297,648,414	717,010	0.0024	0.9976	84.53
47.5	290,928,513	721,384	0.0025	0.9975	84.33
48.5	282,143,053	1,335,054	0.0047	0.9953	84.12
49.5	270,565,877	1,219,135	0.0045	0.9955	83.72
50.5	258,823,308	2,108,575	0.0081	0.9919	83.34
51.5	247,909,144	2,013,782	0.0081	0.9919	82.66
52.5	236,161,995	1,344,571	0.0057	0.9943	81.99
53.5	223,939,449	1,386,253	0.0062	0.9938	81.52
54.5	210,276,162	1,153,741	0.0055	0.9945	81.02
55.5	200,033,282	1,034,753	0.0052	0.9948	80.58
56.5	189,871,245	1,113,905	0.0059	0.9941	80.16
57.5	179,509,914	1,472,337	0.0082	0.9918	79.69
58.5	168,733,350	1,457,086	0.0086	0.9914	79.03
59.5	157,174,909	3,162,422	0.0201	0.9799	78.35
60.5	144,750,847	1,704,714	0.0118	0.9882	76.78
61.5	135,234,572	1,556,621	0.0115	0.9885	75.87
62.5	125,667,169	1,618,307	0.0129	0.9871	75.00
63.5	117,381,528	1,788,042	0.0152	0.9848	74.03
64.5	109,265,425	2,035,463	0.0186	0.9814	72.90
65.5	100,725,662	2,286,905	0.0227	0.9773	71.55
66.5	91,131,852	2,153,575	0.0236	0.9764	69.92
67.5	82,448,276	2,271,671	0.0276	0.9724	68.27
68.5	63,243,817	1,746,199	0.0276	0.9724	66.39
69.5	48,414,112	1,293,734	0.0267	0.9733	64.56
70.5	39,862,683	932,196	0.0234	0.9766	62.83
71.5	33,383,806	602,091	0.0180	0.9820	61.36
72.5	31,285,822	595,530	0.0190	0.9810	60.25
73.5	27,538,015	437,895	0.0159	0.9841	59.11
74.5	22,854,645	267,813	0.0117	0.9883	58.17
75.5	20,530,921	188,829	0.0092	0.9908	57.49
76.5	19,759,869	186,347	0.0094	0.9906	56.96
77.5	19,424,125	209,741	0.0108	0.9892	56.42
78.5	19,057,452	251,803	0.0132	0.9868	55.81

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

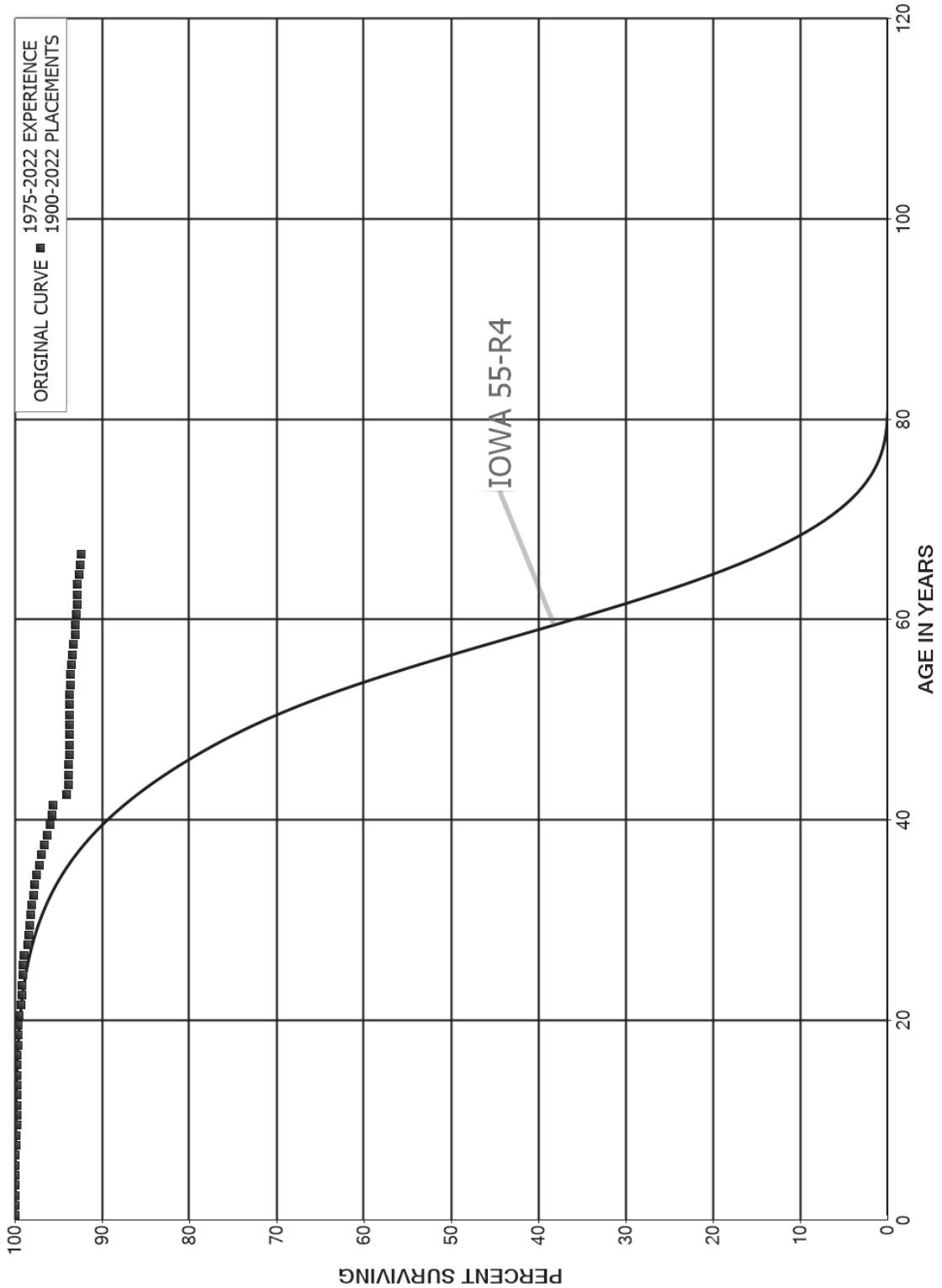
ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	18,446,808	222,678	0.0121	0.9879	55.07
80.5	17,909,718	198,168	0.0111	0.9889	54.41
81.5	17,111,520	196,421	0.0115	0.9885	53.81
82.5	16,201,202	191,863	0.0118	0.9882	53.19
83.5	15,489,998	204,579	0.0132	0.9868	52.56
84.5	14,853,251	189,422	0.0128	0.9872	51.87
85.5	14,375,144	200,582	0.0140	0.9860	51.20
86.5	13,955,271	232,669	0.0167	0.9833	50.49
87.5	13,617,805	288,629	0.0212	0.9788	49.65
88.5	13,160,587	376,303	0.0286	0.9714	48.60
89.5	12,699,371	459,614	0.0362	0.9638	47.21
90.5	11,981,275	477,462	0.0399	0.9601	45.50
91.5	11,028,455	527,288	0.0478	0.9522	43.68
92.5	10,072,141	518,416	0.0515	0.9485	41.60
93.5	8,467,318	546,231	0.0645	0.9355	39.45
94.5	6,746,113	376,070	0.0557	0.9443	36.91
95.5	5,043,855	309,100	0.0613	0.9387	34.85
96.5	3,377,737	194,569	0.0576	0.9424	32.72
97.5	1,931,466	113,326	0.0587	0.9413	30.83
98.5	581,251	28,918	0.0498	0.9502	29.02
99.5					27.58

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	170,906,560	24,103	0.0001	0.9999	100.00
0.5	146,830,289	10,991	0.0001	0.9999	99.99
1.5	125,651,990	2,879	0.0000	1.0000	99.98
2.5	113,990,083	15,415	0.0001	0.9999	99.98
3.5	110,444,003	6,022	0.0001	0.9999	99.96
4.5	99,128,384	25,401	0.0003	0.9997	99.96
5.5	90,416,690	35,447	0.0004	0.9996	99.93
6.5	86,171,092	34,218	0.0004	0.9996	99.89
7.5	81,409,201	1,176	0.0000	1.0000	99.85
8.5	81,447,282	86,175	0.0011	0.9989	99.85
9.5	79,217,797	6,548	0.0001	0.9999	99.75
10.5	76,875,805	782	0.0000	1.0000	99.74
11.5	71,669,471	13,814	0.0002	0.9998	99.74
12.5	60,636,058	8,686	0.0001	0.9999	99.72
13.5	54,714,880	3,309	0.0001	0.9999	99.70
14.5	50,693,070	9,495	0.0002	0.9998	99.70
15.5	44,354,633	2,624	0.0001	0.9999	99.68
16.5	41,467,789	7,961	0.0002	0.9998	99.67
17.5	38,612,451	9,391	0.0002	0.9998	99.65
18.5	36,076,795	6,189	0.0002	0.9998	99.63
19.5	35,251,745	38,807	0.0011	0.9989	99.61
20.5	33,215,772	70,926	0.0021	0.9979	99.50
21.5	32,811,885	33,872	0.0010	0.9990	99.29
22.5	32,801,024	9,752	0.0003	0.9997	99.19
23.5	32,668,495	24,476	0.0007	0.9993	99.16
24.5	32,389,438	13,525	0.0004	0.9996	99.08
25.5	30,742,230	25,064	0.0008	0.9992	99.04
26.5	29,885,499	142,596	0.0048	0.9952	98.96
27.5	28,672,462	22,034	0.0008	0.9992	98.49
28.5	25,390,077	20,771	0.0008	0.9992	98.41
29.5	22,672,104	38,451	0.0017	0.9983	98.33
30.5	19,885,067	18,587	0.0009	0.9991	98.17
31.5	17,144,974	40,469	0.0024	0.9976	98.07
32.5	13,941,291	19,699	0.0014	0.9986	97.84
33.5	11,231,465	27,544	0.0025	0.9975	97.70
34.5	9,557,257	33,594	0.0035	0.9965	97.46
35.5	8,558,338	17,173	0.0020	0.9980	97.12
36.5	7,403,920	21,599	0.0029	0.9971	96.93
37.5	6,377,560	26,869	0.0042	0.9958	96.64
38.5	5,794,393	19,438	0.0034	0.9966	96.24

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,860,628	7,766	0.0016	0.9984	95.91
40.5	3,964,823	6,840	0.0017	0.9983	95.76
41.5	3,379,391	55,980	0.0166	0.9834	95.60
42.5	3,193,091	4,241	0.0013	0.9987	94.01
43.5	3,123,844	961	0.0003	0.9997	93.89
44.5	3,073,359	2,245	0.0007	0.9993	93.86
45.5	2,919,392	1,420	0.0005	0.9995	93.79
46.5	2,899,968		0.0000	1.0000	93.74
47.5	2,851,560		0.0000	1.0000	93.74
48.5	2,750,864		0.0000	1.0000	93.74
49.5	2,681,994	1,144	0.0004	0.9996	93.74
50.5	2,513,079		0.0000	1.0000	93.70
51.5	2,417,176	568	0.0002	0.9998	93.70
52.5	2,308,865	1,010	0.0004	0.9996	93.68
53.5	2,240,343	966	0.0004	0.9996	93.64
54.5	2,180,033	1,704	0.0008	0.9992	93.60
55.5	2,130,526	2,234	0.0010	0.9990	93.53
56.5	2,090,154	3,091	0.0015	0.9985	93.43
57.5	2,047,286	4,113	0.0020	0.9980	93.29
58.5	1,976,460	1,635	0.0008	0.9992	93.10
59.5	1,881,860	2,613	0.0014	0.9986	93.03
60.5	1,718,473	1,436	0.0008	0.9992	92.90
61.5	1,689,303	200	0.0001	0.9999	92.82
62.5	1,449,257	446	0.0003	0.9997	92.81
63.5	1,252,270	2,173	0.0017	0.9983	92.78
64.5	1,211,905	919	0.0008	0.9992	92.62
65.5	1,084,895	2,083	0.0019	0.9981	92.55
66.5	928,010	378	0.0004	0.9996	92.37
67.5	771,215	448	0.0006	0.9994	92.33
68.5	611,436	95	0.0002	0.9998	92.28
69.5	567,882	460	0.0008	0.9992	92.27
70.5	454,110	179	0.0004	0.9996	92.19
71.5	356,352		0.0000	1.0000	92.16
72.5	302,616	1,131	0.0037	0.9963	92.16
73.5	244,393	122	0.0005	0.9995	91.81
74.5	190,084	2,478	0.0130	0.9870	91.77
75.5	157,912	40	0.0003	0.9997	90.57
76.5	145,151	1,097	0.0076	0.9924	90.55
77.5	136,895	707	0.0052	0.9948	89.86
78.5	131,817		0.0000	1.0000	89.40

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

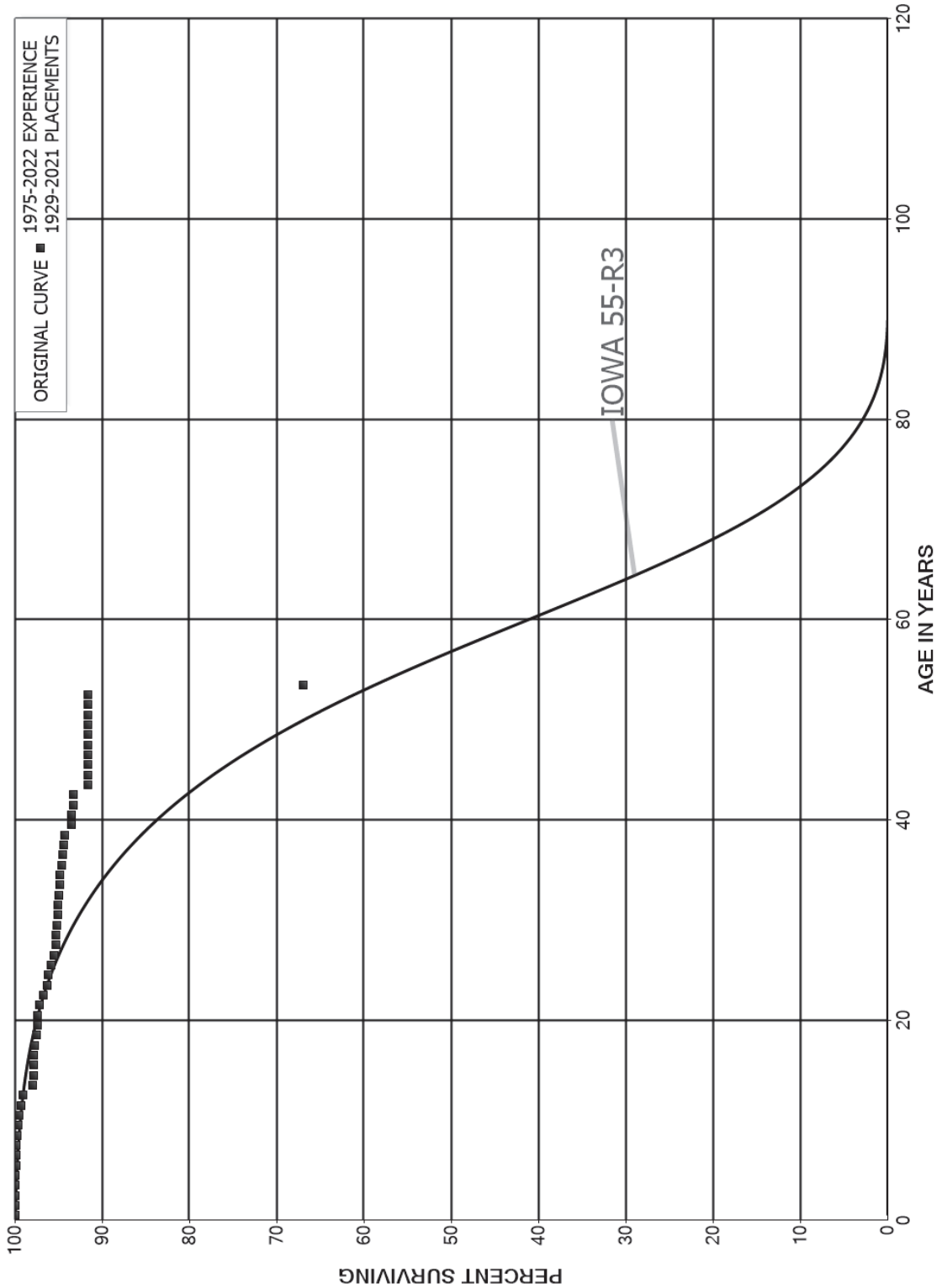
ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	124,985		0.0000	1.0000	89.40
80.5	121,114		0.0000	1.0000	89.40
81.5	114,024	266	0.0023	0.9977	89.40
82.5	105,472		0.0000	1.0000	89.19
83.5	97,256		0.0000	1.0000	89.19
84.5	93,976		0.0000	1.0000	89.19
85.5	90,921		0.0000	1.0000	89.19
86.5	87,502		0.0000	1.0000	89.19
87.5	85,802		0.0000	1.0000	89.19
88.5	85,542		0.0000	1.0000	89.19
89.5	84,939		0.0000	1.0000	89.19
90.5	83,804		0.0000	1.0000	89.19
91.5	75,793		0.0000	1.0000	89.19
92.5	73,127		0.0000	1.0000	89.19
93.5	70,264		0.0000	1.0000	89.19
94.5	61,492		0.0000	1.0000	89.19
95.5	53,249		0.0000	1.0000	89.19
96.5	45,586		0.0000	1.0000	89.19
97.5	40,729		0.0000	1.0000	89.19
98.5	37,702		0.0000	1.0000	89.19
99.5	33,075		0.0000	1.0000	89.19
100.5	28,886		0.0000	1.0000	89.19
101.5	26,479		0.0000	1.0000	89.19
102.5	25,262		0.0000	1.0000	89.19
103.5	24,623		0.0000	1.0000	89.19
104.5	24,029		0.0000	1.0000	89.19
105.5	22,293		0.0000	1.0000	89.19
106.5	21,699		0.0000	1.0000	89.19
107.5	21,307		0.0000	1.0000	89.19
108.5	20,463		0.0000	1.0000	89.19
109.5	18,781		0.0000	1.0000	89.19
110.5	18,001		0.0000	1.0000	89.19
111.5	16,421		0.0000	1.0000	89.19
112.5	14,583		0.0000	1.0000	89.19
113.5	4,010		0.0000	1.0000	89.19
114.5					89.19

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1929-2021 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	99,484,874		0.0000	1.0000	100.00
0.5	106,206,685	452	0.0000	1.0000	100.00
1.5	104,372,594	39,543	0.0004	0.9996	100.00
2.5	88,051,206	446	0.0000	1.0000	99.96
3.5	88,052,793	23,666	0.0003	0.9997	99.96
4.5	88,060,847	64,489	0.0007	0.9993	99.93
5.5	84,242,863	11,903	0.0001	0.9999	99.86
6.5	84,247,745	16,249	0.0002	0.9998	99.85
7.5	83,277,818	48,138	0.0006	0.9994	99.83
8.5	80,360,669	140,099	0.0017	0.9983	99.77
9.5	80,294,982	94,363	0.0012	0.9988	99.60
10.5	76,702,393	188,792	0.0025	0.9975	99.48
11.5	76,610,605	115,216	0.0015	0.9985	99.23
12.5	75,228,674	885,734	0.0118	0.9882	99.08
13.5	74,593,207	22,577	0.0003	0.9997	97.92
14.5	74,824,574	6,401	0.0001	0.9999	97.89
15.5	75,034,833	15,303	0.0002	0.9998	97.88
16.5	75,113,450	81,483	0.0011	0.9989	97.86
17.5	75,034,635	195,243	0.0026	0.9974	97.75
18.5	74,874,878	62,537	0.0008	0.9992	97.50
19.5	74,635,706	57,597	0.0008	0.9992	97.42
20.5	72,632,428	136,554	0.0019	0.9981	97.34
21.5	72,319,919	335,986	0.0046	0.9954	97.16
22.5	72,005,830	328,976	0.0046	0.9954	96.71
23.5	70,455,984	75,466	0.0011	0.9989	96.27
24.5	64,673,600	197,299	0.0031	0.9969	96.16
25.5	62,116,201	202,636	0.0033	0.9967	95.87
26.5	57,614,583	149,791	0.0026	0.9974	95.56
27.5	54,161,916	22,006	0.0004	0.9996	95.31
28.5	43,818,266	68,775	0.0016	0.9984	95.27
29.5	40,540,195	2,510	0.0001	0.9999	95.12
30.5	37,854,608	5,968	0.0002	0.9998	95.12
31.5	36,852,464	72,625	0.0020	0.9980	95.10
32.5	35,620,793	11,131	0.0003	0.9997	94.91
33.5	29,625,833	21,652	0.0007	0.9993	94.88
34.5	28,997,239	68,869	0.0024	0.9976	94.81
35.5	26,169,753	30,595	0.0012	0.9988	94.59
36.5	19,849,094	23,638	0.0012	0.9988	94.48
37.5	18,803,031	11,361	0.0006	0.9994	94.37
38.5	17,010,490	137,554	0.0081	0.9919	94.31

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

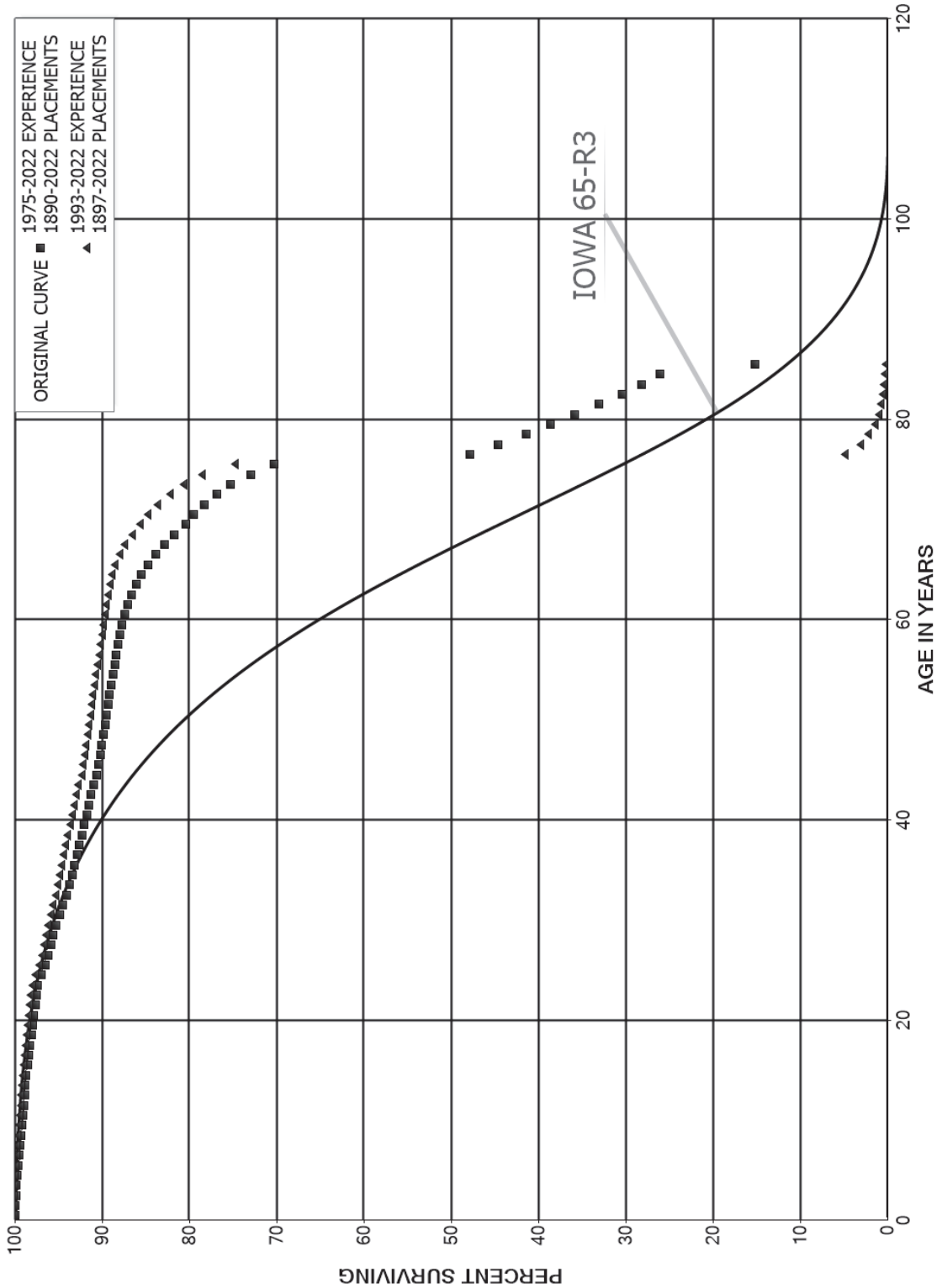
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1929-2021 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,003,640	2,957	0.0002	0.9998	93.55
40.5	13,508,989	30,780	0.0023	0.9977	93.53
41.5	12,210,455		0.0000	1.0000	93.31
42.5	10,441,205	190,044	0.0182	0.9818	93.31
43.5	8,939,094		0.0000	1.0000	91.62
44.5	8,015,967		0.0000	1.0000	91.62
45.5	4,997,286		0.0000	1.0000	91.62
46.5	3,990,977	980	0.0002	0.9998	91.62
47.5	41,850	1	0.0000	1.0000	91.59
48.5	41,849		0.0000	1.0000	91.59
49.5	41,849		0.0000	1.0000	91.59
50.5	41,849		0.0000	1.0000	91.59
51.5	41,849		0.0000	1.0000	91.59
52.5	41,849	11,269	0.2693	0.7307	91.59
53.5	30,580		0.0000	1.0000	66.93
54.5	30,580	226	0.0074	0.9926	66.93
55.5	30,355		0.0000	1.0000	66.43
56.5	30,355		0.0000	1.0000	66.43
57.5	30,355		0.0000	1.0000	66.43
58.5	30,355	90	0.0030	0.9970	66.43
59.5	30,265		0.0000	1.0000	66.24
60.5	8,833		0.0000	1.0000	66.24
61.5					66.24

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 380.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,251,085,123	1,921,910	0.0004	0.9996	100.00
0.5	4,809,327,681	2,661,306	0.0006	0.9994	99.96
1.5	4,340,746,250	2,448,032	0.0006	0.9994	99.91
2.5	4,003,824,195	2,731,287	0.0007	0.9993	99.85
3.5	3,617,376,112	2,767,788	0.0008	0.9992	99.78
4.5	3,153,277,825	2,640,322	0.0008	0.9992	99.71
5.5	2,810,247,651	2,449,185	0.0009	0.9991	99.62
6.5	2,420,192,402	2,625,502	0.0011	0.9989	99.54
7.5	2,109,828,787	2,596,109	0.0012	0.9988	99.43
8.5	1,925,254,798	2,098,148	0.0011	0.9989	99.31
9.5	1,841,627,235	2,034,737	0.0011	0.9989	99.20
10.5	1,771,360,528	1,844,729	0.0010	0.9990	99.09
11.5	1,702,217,756	1,718,090	0.0010	0.9990	98.99
12.5	1,617,335,644	1,726,770	0.0011	0.9989	98.89
13.5	1,537,499,138	1,593,608	0.0010	0.9990	98.78
14.5	1,469,095,094	1,824,251	0.0012	0.9988	98.68
15.5	1,405,346,736	2,370,869	0.0017	0.9983	98.56
16.5	1,339,745,560	1,989,954	0.0015	0.9985	98.39
17.5	1,276,530,190	1,978,261	0.0015	0.9985	98.24
18.5	1,217,484,945	1,650,600	0.0014	0.9986	98.09
19.5	1,155,269,323	1,816,650	0.0016	0.9984	97.96
20.5	1,100,102,952	1,538,455	0.0014	0.9986	97.80
21.5	1,052,848,030	1,616,277	0.0015	0.9985	97.67
22.5	1,003,423,666	1,775,040	0.0018	0.9982	97.52
23.5	956,408,603	4,172,256	0.0044	0.9956	97.34
24.5	893,131,006	4,312,872	0.0048	0.9952	96.92
25.5	837,958,977	2,718,395	0.0032	0.9968	96.45
26.5	792,061,223	2,297,922	0.0029	0.9971	96.14
27.5	741,155,113	2,091,986	0.0028	0.9972	95.86
28.5	682,717,774	2,222,778	0.0033	0.9967	95.59
29.5	633,703,087	2,708,758	0.0043	0.9957	95.28
30.5	586,520,311	2,270,246	0.0039	0.9961	94.87
31.5	543,249,070	2,638,994	0.0049	0.9951	94.50
32.5	499,998,338	1,947,074	0.0039	0.9961	94.04
33.5	459,340,988	1,245,356	0.0027	0.9973	93.68
34.5	420,099,354	1,148,136	0.0027	0.9973	93.42
35.5	379,741,843	1,225,564	0.0032	0.9968	93.17
36.5	340,014,819	975,954	0.0029	0.9971	92.87
37.5	305,178,874	973,494	0.0032	0.9968	92.60
38.5	273,357,761	794,589	0.0029	0.9971	92.31

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	247,754,603	705,063	0.0028	0.9972	92.04
40.5	223,622,972	632,687	0.0028	0.9972	91.78
41.5	200,456,613	533,868	0.0027	0.9973	91.52
42.5	173,049,486	552,576	0.0032	0.9968	91.27
43.5	160,436,005	665,292	0.0041	0.9959	90.98
44.5	145,727,540	314,257	0.0022	0.9978	90.60
45.5	137,404,669	291,262	0.0021	0.9979	90.41
46.5	134,674,292	280,156	0.0021	0.9979	90.22
47.5	126,963,086	272,776	0.0021	0.9979	90.03
48.5	116,997,666	237,902	0.0020	0.9980	89.84
49.5	106,112,500	207,714	0.0020	0.9980	89.65
50.5	95,070,190	187,711	0.0020	0.9980	89.48
51.5	90,484,336	165,558	0.0018	0.9982	89.30
52.5	81,978,864	172,842	0.0021	0.9979	89.14
53.5	73,407,296	156,340	0.0021	0.9979	88.95
54.5	65,909,684	153,082	0.0023	0.9977	88.76
55.5	58,890,449	130,709	0.0022	0.9978	88.55
56.5	52,557,908	126,892	0.0024	0.9976	88.36
57.5	47,180,931	118,417	0.0025	0.9975	88.14
58.5	41,547,562	113,396	0.0027	0.9973	87.92
59.5	36,342,085	127,571	0.0035	0.9965	87.68
60.5	31,618,370	130,666	0.0041	0.9959	87.38
61.5	28,172,781	134,712	0.0048	0.9952	87.01
62.5	24,451,234	147,392	0.0060	0.9940	86.60
63.5	20,519,827	137,725	0.0067	0.9933	86.08
64.5	17,184,260	152,289	0.0089	0.9911	85.50
65.5	14,330,951	149,508	0.0104	0.9896	84.74
66.5	11,663,989	136,792	0.0117	0.9883	83.86
67.5	9,520,784	126,125	0.0132	0.9868	82.87
68.5	7,721,661	125,194	0.0162	0.9838	81.78
69.5	7,620,042	93,401	0.0123	0.9877	80.45
70.5	5,987,921	90,954	0.0152	0.9848	79.46
71.5	4,461,952	81,947	0.0184	0.9816	78.26
72.5	3,194,200	65,790	0.0206	0.9794	76.82
73.5	2,306,405	68,947	0.0299	0.9701	75.24
74.5	1,757,026	65,206	0.0371	0.9629	72.99
75.5	1,591,323	507,005	0.3186	0.6814	70.28
76.5	1,084,807	75,167	0.0693	0.9307	47.89
77.5	1,009,838	71,512	0.0708	0.9292	44.57
78.5	939,393	64,167	0.0683	0.9317	41.41

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	875,264	63,232	0.0722	0.9278	38.58
80.5	812,198	61,145	0.0753	0.9247	35.80
81.5	751,053	60,662	0.0808	0.9192	33.10
82.5	690,747	50,235	0.0727	0.9273	30.43
83.5	641,190	49,026	0.0765	0.9235	28.22
84.5	594,350	247,374	0.4162	0.5838	26.06
85.5	346,976	32,469	0.0936	0.9064	15.21
86.5	314,507	42,094	0.1338	0.8662	13.79
87.5	272,413	23,182	0.0851	0.9149	11.94
88.5	249,231	41,859	0.1680	0.8320	10.93
89.5	207,371	19,846	0.0957	0.9043	9.09
90.5	187,526	12,353	0.0659	0.9341	8.22
91.5	175,172	22,383	0.1278	0.8722	7.68
92.5	152,789	29,098	0.1904	0.8096	6.70
93.5	123,692	20,633	0.1668	0.8332	5.42
94.5	103,059	49,341	0.4788	0.5212	4.52
95.5	53,718	34,406	0.6405	0.3595	2.36
96.5	19,312	7,549	0.3909	0.6091	0.85
97.5	11,763	9,277	0.7886	0.2114	0.52
98.5	2,487	2,086	0.8388	0.1612	0.11
99.5	401	401	1.0000		0.02
100.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1897-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,732,789,374	1,050,696	0.0002	0.9998	100.00
0.5	4,327,301,983	1,563,647	0.0004	0.9996	99.98
1.5	3,890,320,840	1,453,197	0.0004	0.9996	99.94
2.5	3,584,346,656	1,953,073	0.0005	0.9995	99.90
3.5	3,232,826,856	2,005,860	0.0006	0.9994	99.85
4.5	2,799,435,712	1,808,064	0.0006	0.9994	99.79
5.5	2,488,493,524	1,684,020	0.0007	0.9993	99.72
6.5	2,122,812,360	1,827,116	0.0009	0.9991	99.66
7.5	1,842,630,751	1,818,017	0.0010	0.9990	99.57
8.5	1,683,685,106	1,573,345	0.0009	0.9991	99.47
9.5	1,619,761,858	1,398,957	0.0009	0.9991	99.38
10.5	1,568,352,683	1,292,745	0.0008	0.9992	99.29
11.5	1,517,244,704	1,268,989	0.0008	0.9992	99.21
12.5	1,455,349,493	1,290,526	0.0009	0.9991	99.13
13.5	1,387,911,788	1,171,716	0.0008	0.9992	99.04
14.5	1,330,335,371	1,402,277	0.0011	0.9989	98.96
15.5	1,271,016,723	1,906,139	0.0015	0.9985	98.85
16.5	1,209,137,158	1,532,356	0.0013	0.9987	98.70
17.5	1,150,715,540	1,487,940	0.0013	0.9987	98.58
18.5	1,098,970,893	1,105,453	0.0010	0.9990	98.45
19.5	1,045,236,779	1,254,038	0.0012	0.9988	98.35
20.5	999,102,202	1,072,760	0.0011	0.9989	98.23
21.5	955,479,167	1,105,986	0.0012	0.9988	98.13
22.5	913,685,517	1,258,734	0.0014	0.9986	98.02
23.5	874,197,449	3,646,030	0.0042	0.9958	97.88
24.5	818,162,688	3,817,080	0.0047	0.9953	97.47
25.5	769,671,852	2,163,553	0.0028	0.9972	97.02
26.5	730,067,790	1,751,762	0.0024	0.9976	96.74
27.5	685,357,949	1,592,010	0.0023	0.9977	96.51
28.5	633,246,705	1,629,512	0.0026	0.9974	96.29
29.5	590,302,908	1,701,976	0.0029	0.9971	96.04
30.5	549,087,983	1,368,415	0.0025	0.9975	95.76
31.5	510,621,845	1,808,588	0.0035	0.9965	95.53
32.5	472,072,347	1,343,348	0.0028	0.9972	95.19
33.5	436,202,378	927,257	0.0021	0.9979	94.92
34.5	400,732,357	882,648	0.0022	0.9978	94.71
35.5	363,601,453	962,306	0.0026	0.9974	94.51
36.5	326,962,931	742,627	0.0023	0.9977	94.26
37.5	294,916,547	810,268	0.0027	0.9973	94.04
38.5	265,500,894	668,817	0.0025	0.9975	93.78

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	240,380,676	608,393	0.0025	0.9975	93.55
40.5	217,998,773	558,446	0.0026	0.9974	93.31
41.5	196,501,555	459,281	0.0023	0.9977	93.07
42.5	170,466,084	505,404	0.0030	0.9970	92.85
43.5	158,793,621	634,556	0.0040	0.9960	92.58
44.5	144,767,053	286,104	0.0020	0.9980	92.21
45.5	136,518,928	257,457	0.0019	0.9981	92.03
46.5	133,716,258	249,350	0.0019	0.9981	91.85
47.5	125,891,952	231,467	0.0018	0.9982	91.68
48.5	115,802,781	200,123	0.0017	0.9983	91.51
49.5	104,799,556	173,521	0.0017	0.9983	91.35
50.5	93,660,067	150,738	0.0016	0.9984	91.20
51.5	89,027,631	142,509	0.0016	0.9984	91.06
52.5	80,473,369	143,118	0.0018	0.9982	90.91
53.5	71,879,222	135,049	0.0019	0.9981	90.75
54.5	63,940,128	131,324	0.0021	0.9979	90.58
55.5	56,911,290	110,332	0.0019	0.9981	90.39
56.5	50,599,043	98,736	0.0020	0.9980	90.22
57.5	45,213,468	85,151	0.0019	0.9981	90.04
58.5	39,572,336	71,940	0.0018	0.9982	89.87
59.5	34,362,858	61,723	0.0018	0.9982	89.71
60.5	29,674,617	57,386	0.0019	0.9981	89.55
61.5	26,269,908	51,129	0.0019	0.9981	89.37
62.5	22,574,185	52,794	0.0023	0.9977	89.20
63.5	18,584,619	56,460	0.0030	0.9970	88.99
64.5	15,333,981	64,221	0.0042	0.9958	88.72
65.5	12,586,786	65,698	0.0052	0.9948	88.35
66.5	10,047,980	70,586	0.0070	0.9930	87.89
67.5	7,787,619	76,845	0.0099	0.9901	87.27
68.5	6,065,547	65,147	0.0107	0.9893	86.41
69.5	6,046,775	61,982	0.0103	0.9897	85.48
70.5	4,465,860	55,221	0.0124	0.9876	84.61
71.5	2,968,200	53,987	0.0182	0.9818	83.56
72.5	2,150,269	39,454	0.0183	0.9817	82.04
73.5	1,283,290	34,873	0.0272	0.9728	80.53
74.5	580,707	27,852	0.0480	0.9520	78.35
75.5	470,852	440,726	0.9360	0.0640	74.59
76.5	46,828	17,803	0.3802	0.6198	4.77
77.5	47,096	14,475	0.3074	0.6926	2.96
78.5	45,738	17,329	0.3789	0.6211	2.05

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

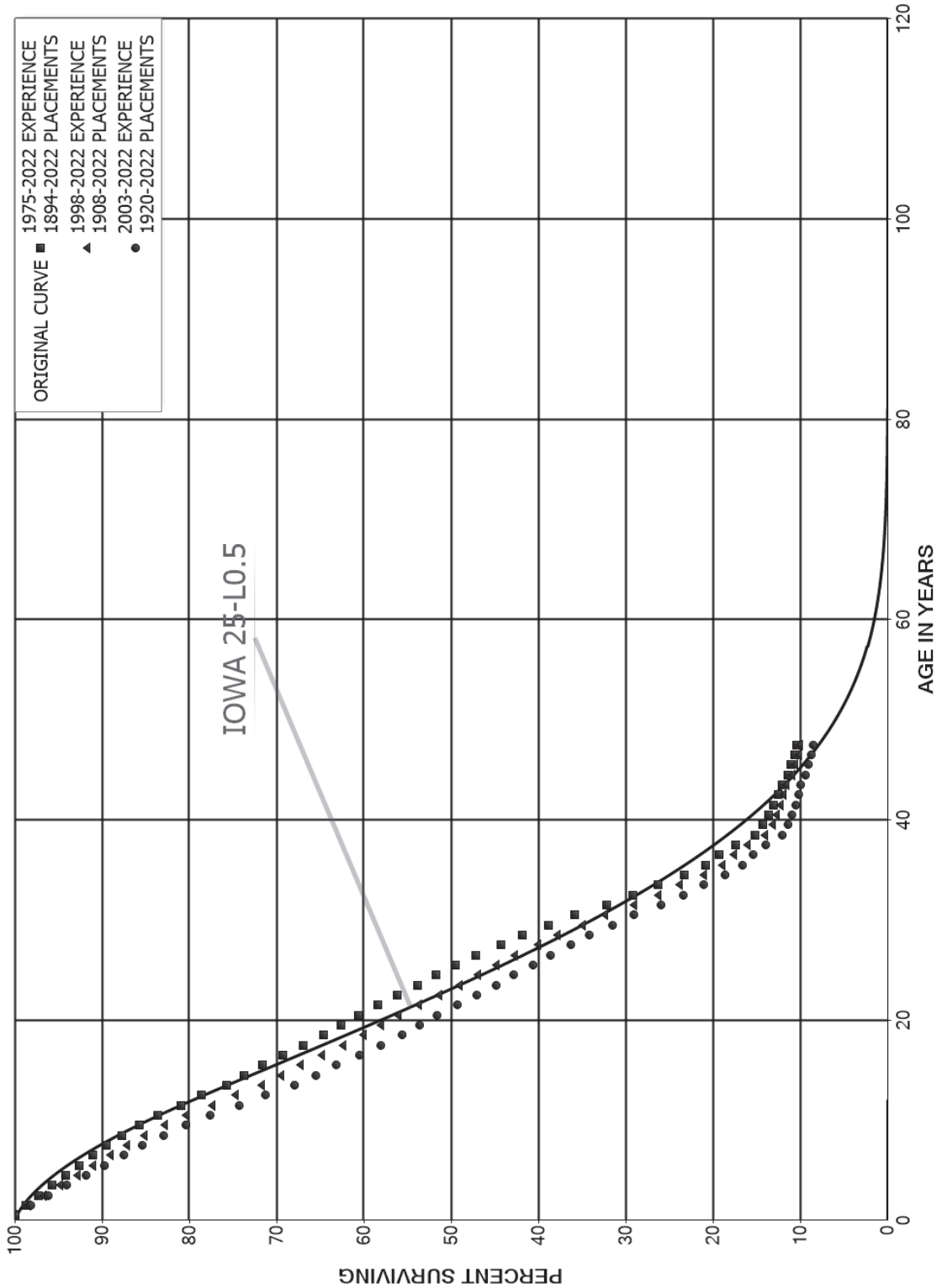
ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2022 EXPERIENCE BAND 1993-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	49,700	15,109	0.3040	0.6960	1.27
80.5	79,358	26,324	0.3317	0.6683	0.89
81.5	112,129	37,320	0.3328	0.6672	0.59
82.5	94,492	30,435	0.3221	0.6779	0.39
83.5	76,787	31,281	0.4074	0.5926	0.27
84.5	53,000	21,138	0.3988	0.6012	0.16
85.5	40,773	14,980	0.3674	0.6326	0.10
86.5	33,613	15,198	0.4522	0.5478	0.06
87.5	25,243	9,875	0.3912	0.6088	0.03
88.5	20,286	7,338	0.3617	0.6383	0.02
89.5	18,405	6,826	0.3709	0.6291	0.01
90.5	15,874	6,675	0.4205	0.5795	0.01
91.5	17,286	6,887	0.3984	0.6016	0.00
92.5	147,720	28,395	0.1922	0.8078	0.00
93.5	120,079	20,517	0.1709	0.8291	0.00
94.5	99,595	49,310	0.4951	0.5049	0.00
95.5	50,332	34,303	0.6815	0.3185	0.00
96.5	16,029	7,150	0.4461	0.5539	0.00
97.5	8,878	8,832	0.9947	0.0053	0.00
98.5	47	47	1.0000		0.00
99.5					

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1894-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	989,928,420	712,174	0.0007	0.9993	100.00
0.5	942,530,733	11,395,775	0.0121	0.9879	99.93
1.5	852,670,797	12,283,471	0.0144	0.9856	98.72
2.5	786,421,068	12,410,177	0.0158	0.9842	97.30
3.5	722,056,832	12,107,592	0.0168	0.9832	95.76
4.5	658,738,034	10,499,893	0.0159	0.9841	94.16
5.5	605,243,925	10,747,265	0.0178	0.9822	92.66
6.5	566,975,474	9,470,111	0.0167	0.9833	91.01
7.5	541,858,032	10,568,022	0.0195	0.9805	89.49
8.5	518,274,786	11,755,117	0.0227	0.9773	87.74
9.5	497,947,474	12,487,056	0.0251	0.9749	85.75
10.5	474,279,931	14,785,685	0.0312	0.9688	83.60
11.5	445,772,837	13,375,025	0.0300	0.9700	81.00
12.5	416,471,405	14,985,699	0.0360	0.9640	78.57
13.5	390,488,225	10,578,256	0.0271	0.9729	75.74
14.5	365,405,788	10,370,054	0.0284	0.9716	73.69
15.5	342,398,719	11,206,049	0.0327	0.9673	71.60
16.5	317,721,746	10,536,365	0.0332	0.9668	69.25
17.5	299,388,022	10,552,173	0.0352	0.9648	66.96
18.5	276,097,159	8,425,376	0.0305	0.9695	64.60
19.5	256,447,838	8,018,763	0.0313	0.9687	62.63
20.5	237,422,446	8,886,503	0.0374	0.9626	60.67
21.5	224,302,570	8,632,515	0.0385	0.9615	58.40
22.5	207,807,278	8,476,808	0.0408	0.9592	56.15
23.5	191,251,239	7,447,800	0.0389	0.9611	53.86
24.5	179,862,560	7,899,355	0.0439	0.9561	51.76
25.5	168,767,928	8,007,155	0.0474	0.9526	49.49
26.5	155,739,706	9,602,960	0.0617	0.9383	47.14
27.5	138,973,754	7,636,778	0.0550	0.9450	44.23
28.5	124,788,458	8,996,570	0.0721	0.9279	41.80
29.5	109,519,126	8,393,105	0.0766	0.9234	38.79
30.5	95,307,521	9,623,354	0.1010	0.8990	35.82
31.5	80,761,601	7,689,961	0.0952	0.9048	32.20
32.5	68,371,220	6,721,625	0.0983	0.9017	29.13
33.5	57,667,195	6,640,514	0.1152	0.8848	26.27
34.5	47,136,208	4,916,135	0.1043	0.8957	23.25
35.5	37,789,077	2,842,091	0.0752	0.9248	20.82
36.5	30,835,588	2,903,831	0.0942	0.9058	19.25
37.5	24,819,724	3,165,705	0.1275	0.8725	17.44
38.5	19,450,315	1,237,769	0.0636	0.9364	15.22

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,659,272	770,301	0.0462	0.9538	14.25
40.5	14,600,360	539,886	0.0370	0.9630	13.59
41.5	12,878,145	592,789	0.0460	0.9540	13.09
42.5	10,984,649	401,746	0.0366	0.9634	12.48
43.5	9,572,019	480,423	0.0502	0.9498	12.03
44.5	8,521,100	280,959	0.0330	0.9670	11.42
45.5	7,836,870	319,033	0.0407	0.9593	11.05
46.5	7,291,747	149,575	0.0205	0.9795	10.60
47.5	6,955,665	117,264	0.0169	0.9831	10.38
48.5	6,527,467	84,875	0.0130	0.9870	10.21
49.5	6,084,369	60,350	0.0099	0.9901	10.07
50.5	5,474,159	38,926	0.0071	0.9929	9.97
51.5	5,089,446	22,231	0.0044	0.9956	9.90
52.5	4,664,244	9,571	0.0021	0.9979	9.86
53.5	4,223,315	2,213	0.0005	0.9995	9.84
54.5	3,820,611	3,130	0.0008	0.9992	9.83
55.5	3,467,523	6,967	0.0020	0.9980	9.83
56.5	3,128,450	10,153	0.0032	0.9968	9.81
57.5	2,820,189	6,430	0.0023	0.9977	9.77
58.5	2,501,745	3,300	0.0013	0.9987	9.75
59.5	2,217,972	2,194	0.0010	0.9990	9.74
60.5	1,948,445	1,413	0.0007	0.9993	9.73
61.5	1,748,574	1,156	0.0007	0.9993	9.72
62.5	1,539,042	170	0.0001	0.9999	9.72
63.5	1,332,288	66	0.0000	1.0000	9.71
64.5	1,173,943	1,487	0.0013	0.9987	9.71
65.5	1,013,971	3,566	0.0035	0.9965	9.70
66.5	849,575	10,937	0.0129	0.9871	9.67
67.5	690,418	2,535	0.0037	0.9963	9.54
68.5	565,546	1,829	0.0032	0.9968	9.51
69.5	461,165	637	0.0014	0.9986	9.48
70.5	394,883	909	0.0023	0.9977	9.46
71.5	330,051	874	0.0026	0.9974	9.44
72.5	271,179	19	0.0001	0.9999	9.42
73.5	231,143		0.0000	1.0000	9.42
74.5	187,622	19	0.0001	0.9999	9.42
75.5	148,316	358	0.0024	0.9976	9.42
76.5	131,941	179	0.0014	0.9986	9.39
77.5	121,629	125	0.0010	0.9990	9.38
78.5	116,106	194	0.0017	0.9983	9.37

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	105,816	54	0.0005	0.9995	9.36
80.5	90,223	29	0.0003	0.9997	9.35
81.5	70,148	13	0.0002	0.9998	9.35
82.5	54,101	96	0.0018	0.9982	9.35
83.5	42,307	3	0.0001	0.9999	9.33
84.5	34,004		0.0000	1.0000	9.33
85.5	31,433	43	0.0014	0.9986	9.33
86.5	29,733	188	0.0063	0.9937	9.32
87.5	28,109	9	0.0003	0.9997	9.26
88.5	27,278	371	0.0136	0.9864	9.25
89.5	26,150	9	0.0004	0.9996	9.13
90.5	24,794		0.0000	1.0000	9.12
91.5	22,917	38	0.0016	0.9984	9.12
92.5	20,464	28	0.0014	0.9986	9.11
93.5	17,479		0.0000	1.0000	9.10
94.5	14,681	9	0.0006	0.9994	9.10
95.5	11,741	19	0.0016	0.9984	9.09
96.5	8,791		0.0000	1.0000	9.08
97.5	6,349		0.0000	1.0000	9.08
98.5	4,396		0.0000	1.0000	9.08
99.5	2,930		0.0000	1.0000	9.08
100.5	1,954		0.0000	1.0000	9.08
101.5	977		0.0000	1.0000	9.08
102.5					9.08

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	802,502,127	702,413	0.0009	0.9991	100.00
0.5	767,969,213	11,388,492	0.0148	0.9852	99.91
1.5	677,828,664	12,282,056	0.0181	0.9819	98.43
2.5	625,199,627	12,407,744	0.0198	0.9802	96.65
3.5	577,120,958	12,043,480	0.0209	0.9791	94.73
4.5	527,261,617	10,464,730	0.0198	0.9802	92.75
5.5	487,060,313	10,740,218	0.0221	0.9779	90.91
6.5	459,654,393	9,418,632	0.0205	0.9795	88.91
7.5	445,120,869	10,556,184	0.0237	0.9763	87.09
8.5	431,554,937	11,737,085	0.0272	0.9728	85.02
9.5	416,960,240	12,395,817	0.0297	0.9703	82.71
10.5	404,463,436	14,760,054	0.0365	0.9635	80.25
11.5	384,969,264	13,357,167	0.0347	0.9653	77.32
12.5	364,208,555	14,956,904	0.0411	0.9589	74.64
13.5	344,397,310	10,562,612	0.0307	0.9693	71.57
14.5	324,012,504	10,360,631	0.0320	0.9680	69.38
15.5	305,119,853	11,157,730	0.0366	0.9634	67.16
16.5	285,070,341	10,526,613	0.0369	0.9631	64.70
17.5	262,973,727	10,222,140	0.0389	0.9611	62.31
18.5	242,876,665	8,067,868	0.0332	0.9668	59.89
19.5	225,009,888	7,666,264	0.0341	0.9659	57.90
20.5	207,484,626	8,602,890	0.0415	0.9585	55.93
21.5	192,505,857	8,260,291	0.0429	0.9571	53.61
22.5	177,906,610	8,205,594	0.0461	0.9539	51.31
23.5	162,097,102	7,070,043	0.0436	0.9564	48.94
24.5	161,152,355	7,344,598	0.0456	0.9544	46.81
25.5	151,241,347	7,054,361	0.0466	0.9534	44.68
26.5	139,543,209	8,656,369	0.0620	0.9380	42.59
27.5	124,142,764	6,920,063	0.0557	0.9443	39.95
28.5	111,333,341	8,390,966	0.0754	0.9246	37.72
29.5	97,061,542	7,154,755	0.0737	0.9263	34.88
30.5	84,545,839	8,741,469	0.1034	0.8966	32.31
31.5	71,212,253	6,776,321	0.0952	0.9048	28.97
32.5	60,221,371	5,825,999	0.0967	0.9033	26.21
33.5	50,711,741	5,847,912	0.1153	0.8847	23.68
34.5	41,240,501	4,243,990	0.1029	0.8971	20.95
35.5	32,831,039	2,251,788	0.0686	0.9314	18.79
36.5	26,674,184	2,436,860	0.0914	0.9086	17.50
37.5	21,354,428	2,679,429	0.1255	0.8745	15.90
38.5	16,692,008	951,188	0.0570	0.9430	13.91

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,362,754	558,087	0.0389	0.9611	13.11
40.5	12,702,305	396,791	0.0312	0.9688	12.60
41.5	11,306,051	345,242	0.0305	0.9695	12.21
42.5	9,836,132	313,350	0.0319	0.9681	11.84
43.5	8,660,904	448,618	0.0518	0.9482	11.46
44.5	7,758,102	253,158	0.0326	0.9674	10.87
45.5	7,181,725	292,582	0.0407	0.9593	10.51
46.5	6,738,785	115,670	0.0172	0.9828	10.08
47.5	6,514,217	94,379	0.0145	0.9855	9.91
48.5	6,165,572	64,296	0.0104	0.9896	9.77
49.5	5,793,244	38,496	0.0066	0.9934	9.67
50.5	5,257,392	30,700	0.0058	0.9942	9.60
51.5	4,909,777	13,849	0.0028	0.9972	9.55
52.5	4,506,152	6,862	0.0015	0.9985	9.52
53.5	4,073,481	1,759	0.0004	0.9996	9.50
54.5	3,680,426	281	0.0001	0.9999	9.50
55.5	3,346,844	1,199	0.0004	0.9996	9.50
56.5	3,036,340	2,770	0.0009	0.9991	9.50
57.5	2,753,667	2,171	0.0008	0.9992	9.49
58.5	2,452,181	1,010	0.0004	0.9996	9.48
59.5	2,179,657	699	0.0003	0.9997	9.48
60.5	1,914,771	669	0.0003	0.9997	9.47
61.5	1,716,022	94	0.0001	0.9999	9.47
62.5	1,505,676	76	0.0001	0.9999	9.47
63.5	1,297,580	19	0.0000	1.0000	9.47
64.5	1,137,674	66	0.0001	0.9999	9.47
65.5	978,791	94	0.0001	0.9999	9.47
66.5	819,211	8,675	0.0106	0.9894	9.47
67.5	663,916	85	0.0001	0.9999	9.37
68.5	543,625	9	0.0000	1.0000	9.37
69.5	443,890	66	0.0001	0.9999	9.37
70.5	381,081		0.0000	1.0000	9.36
71.5	320,088		0.0000	1.0000	9.36
72.5	264,193	9	0.0000	1.0000	9.36
73.5	225,363		0.0000	1.0000	9.36
74.5	183,182		0.0000	1.0000	9.36
75.5	144,678		0.0000	1.0000	9.36
76.5	129,585		0.0000	1.0000	9.36
77.5	120,408		0.0000	1.0000	9.36
78.5	115,006		0.0000	1.0000	9.36

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL		RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	104,908			0.0000	1.0000	9.36
80.5	89,366			0.0000	1.0000	9.36
81.5	69,320			0.0000	1.0000	9.36
82.5	53,287			0.0000	1.0000	9.36
83.5	41,589			0.0000	1.0000	9.36
84.5	33,288			0.0000	1.0000	9.36
85.5	30,718			0.0000	1.0000	9.36
86.5	29,060			0.0000	1.0000	9.36
87.5	27,624			0.0000	1.0000	9.36
88.5	26,803			0.0000	1.0000	9.36
89.5	26,055		9	0.0004	0.9996	9.36
90.5	24,699			0.0000	1.0000	9.36
91.5	22,823			0.0000	1.0000	9.36
92.5	20,407			0.0000	1.0000	9.36
93.5	17,451			0.0000	1.0000	9.36
94.5	14,652			0.0000	1.0000	9.36
95.5	11,722			0.0000	1.0000	9.36
96.5	8,791			0.0000	1.0000	9.36
97.5	6,349			0.0000	1.0000	9.36
98.5	4,396			0.0000	1.0000	9.36
99.5	2,930			0.0000	1.0000	9.36
100.5	1,954			0.0000	1.0000	9.36
101.5	977			0.0000	1.0000	9.36
102.5						9.36

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1920-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	703,945,397	702,359	0.0010	0.9990	100.00
0.5	669,456,137	11,353,165	0.0170	0.9830	99.90
1.5	605,309,971	12,244,614	0.0202	0.9798	98.21
2.5	555,847,298	12,405,048	0.0223	0.9777	96.22
3.5	512,664,237	12,043,265	0.0235	0.9765	94.07
4.5	458,813,652	10,460,026	0.0228	0.9772	91.86
5.5	418,044,636	10,739,627	0.0257	0.9743	89.77
6.5	389,427,856	9,414,377	0.0242	0.9758	87.46
7.5	378,153,983	10,555,110	0.0279	0.9721	85.35
8.5	371,010,021	11,736,356	0.0316	0.9684	82.97
9.5	359,741,092	12,392,136	0.0344	0.9656	80.34
10.5	349,775,337	14,753,608	0.0422	0.9578	77.57
11.5	332,251,407	13,355,021	0.0402	0.9598	74.30
12.5	313,689,035	14,952,702	0.0477	0.9523	71.31
13.5	297,811,326	10,552,579	0.0354	0.9646	67.92
14.5	283,060,631	10,286,744	0.0363	0.9637	65.51
15.5	271,312,693	11,156,262	0.0411	0.9589	63.13
16.5	255,784,734	10,521,868	0.0411	0.9589	60.53
17.5	240,539,542	10,217,138	0.0425	0.9575	58.04
18.5	223,797,092	8,066,617	0.0360	0.9640	55.58
19.5	209,231,772	7,646,299	0.0365	0.9635	53.57
20.5	194,672,205	8,600,701	0.0442	0.9558	51.62
21.5	183,004,173	8,259,378	0.0451	0.9549	49.34
22.5	168,676,014	8,204,205	0.0486	0.9514	47.11
23.5	155,356,948	7,056,461	0.0454	0.9546	44.82
24.5	145,884,935	7,331,787	0.0503	0.9497	42.78
25.5	136,686,247	6,734,326	0.0493	0.9507	40.63
26.5	126,333,390	7,639,894	0.0605	0.9395	38.63
27.5	112,859,244	6,443,099	0.0571	0.9429	36.29
28.5	100,395,902	8,046,095	0.0801	0.9199	34.22
29.5	94,319,911	7,147,306	0.0758	0.9242	31.48
30.5	82,051,028	8,732,987	0.1064	0.8936	29.09
31.5	68,831,204	6,767,714	0.0983	0.9017	26.00
32.5	57,827,009	5,819,932	0.1006	0.8994	23.44
33.5	48,684,176	5,729,122	0.1177	0.8823	21.08
34.5	39,443,905	4,228,264	0.1072	0.8928	18.60
35.5	31,224,988	2,235,220	0.0716	0.9284	16.61
36.5	25,199,326	2,418,501	0.0960	0.9040	15.42
37.5	20,060,639	2,657,255	0.1325	0.8675	13.94
38.5	15,509,251	936,840	0.0604	0.9396	12.09

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	13,297,047	541,017	0.0407	0.9593	11.36
40.5	11,733,911	369,864	0.0315	0.9685	10.90
41.5	10,380,723	322,887	0.0311	0.9689	10.56
42.5	8,967,403	284,951	0.0318	0.9682	10.23
43.5	7,878,448	420,805	0.0534	0.9466	9.90
44.5	7,045,329	236,906	0.0336	0.9664	9.37
45.5	6,562,424	275,219	0.0419	0.9581	9.06
46.5	6,219,577	100,940	0.0162	0.9838	8.68
47.5	6,078,289	72,157	0.0119	0.9881	8.54
48.5	5,815,430	45,462	0.0078	0.9922	8.44
49.5	5,511,846	29,462	0.0053	0.9947	8.37
50.5	4,996,235	15,713	0.0031	0.9969	8.33
51.5	4,697,193	8,239	0.0018	0.9982	8.30
52.5	4,343,335	2,825	0.0007	0.9993	8.28
53.5	3,948,930	617	0.0002	0.9998	8.28
54.5	3,590,490	206	0.0001	0.9999	8.28
55.5	3,279,807	85	0.0000	1.0000	8.28
56.5	2,972,342	13	0.0000	1.0000	8.28
57.5	2,684,375		0.0000	1.0000	8.28
58.5	2,377,754		0.0000	1.0000	8.28
59.5	2,107,369	31	0.0000	1.0000	8.28
60.5	1,855,454		0.0000	1.0000	8.28
61.5	1,675,667		0.0000	1.0000	8.28
62.5	1,479,938		0.0000	1.0000	8.28
63.5	1,282,775		0.0000	1.0000	8.28
64.5	1,130,365		0.0000	1.0000	8.28
65.5	972,679		0.0000	1.0000	8.28
66.5	812,955	8,656	0.0106	0.9894	8.28
67.5	656,615		0.0000	1.0000	8.19
68.5	534,263		0.0000	1.0000	8.19
69.5	432,431		0.0000	1.0000	8.19
70.5	368,103		0.0000	1.0000	8.19
71.5	306,057		0.0000	1.0000	8.19
72.5	250,125		0.0000	1.0000	8.19
73.5	212,308		0.0000	1.0000	8.19
74.5	171,460		0.0000	1.0000	8.19
75.5	134,910		0.0000	1.0000	8.19
76.5	121,770		0.0000	1.0000	8.19
77.5	114,059		0.0000	1.0000	8.19
78.5	110,610		0.0000	1.0000	8.19

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

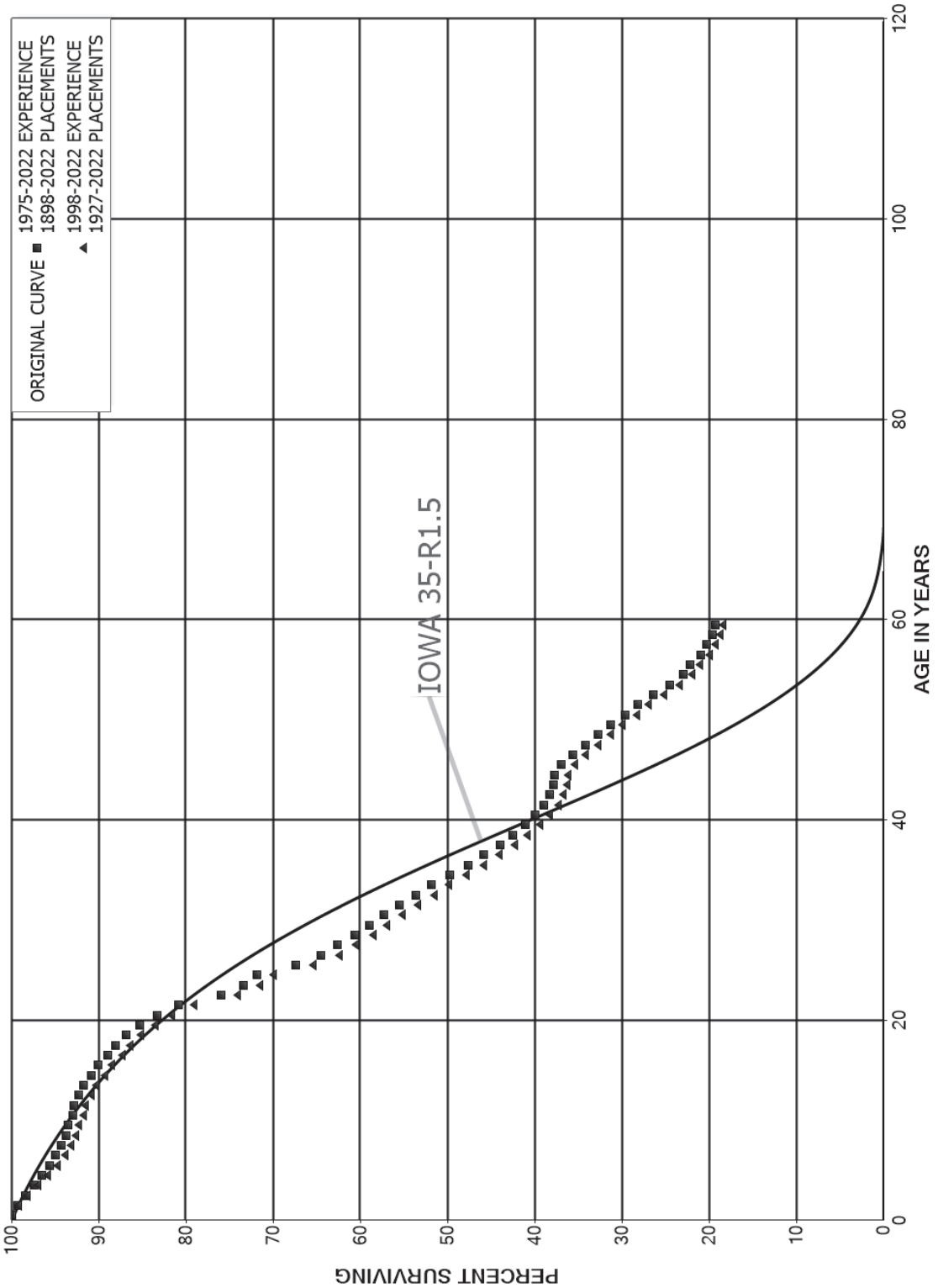
ACCOUNTS 381.00 TO 384.00 METERS AND HOUSE REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2022 EXPERIENCE BAND 2003-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	101,978		0.0000	1.0000	8.19
80.5	87,412		0.0000	1.0000	8.19
81.5	68,344		0.0000	1.0000	8.19
82.5	53,287		0.0000	1.0000	8.19
83.5	41,589		0.0000	1.0000	8.19
84.5	33,288		0.0000	1.0000	8.19
85.5	30,718		0.0000	1.0000	8.19
86.5	29,060		0.0000	1.0000	8.19
87.5	27,624		0.0000	1.0000	8.19
88.5	26,803		0.0000	1.0000	8.19
89.5	26,046		0.0000	1.0000	8.19
90.5	24,699		0.0000	1.0000	8.19
91.5	22,823		0.0000	1.0000	8.19
92.5	20,407		0.0000	1.0000	8.19
93.5	17,451		0.0000	1.0000	8.19
94.5	14,652		0.0000	1.0000	8.19
95.5	11,722		0.0000	1.0000	8.19
96.5	8,791		0.0000	1.0000	8.19
97.5	6,349		0.0000	1.0000	8.19
98.5	4,396		0.0000	1.0000	8.19
99.5	2,930		0.0000	1.0000	8.19
100.5	1,954		0.0000	1.0000	8.19
101.5	977		0.0000	1.0000	8.19
102.5					8.19

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1898-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	164,587,557		0.0000	1.0000	100.00
0.5	154,304,856	1,101,643	0.0071	0.9929	100.00
1.5	145,108,331	1,272,653	0.0088	0.9912	99.29
2.5	128,452,841	1,273,903	0.0099	0.9901	98.42
3.5	111,284,494	1,016,892	0.0091	0.9909	97.44
4.5	100,222,609	1,011,945	0.0101	0.9899	96.55
5.5	89,366,536	625,202	0.0070	0.9930	95.57
6.5	78,763,476	480,951	0.0061	0.9939	94.91
7.5	71,771,727	418,056	0.0058	0.9942	94.33
8.5	64,812,123	164,261	0.0025	0.9975	93.78
9.5	60,725,054	368,631	0.0061	0.9939	93.54
10.5	55,578,709	104,175	0.0019	0.9981	92.97
11.5	55,250,047	307,961	0.0056	0.9944	92.80
12.5	54,783,057	312,745	0.0057	0.9943	92.28
13.5	53,985,904	549,577	0.0102	0.9898	91.75
14.5	52,766,357	430,354	0.0082	0.9918	90.82
15.5	51,341,801	656,193	0.0128	0.9872	90.08
16.5	49,517,104	506,650	0.0102	0.9898	88.93
17.5	47,927,512	652,496	0.0136	0.9864	88.02
18.5	45,944,717	839,266	0.0183	0.9817	86.82
19.5	44,139,273	1,007,703	0.0228	0.9772	85.23
20.5	42,320,404	1,258,875	0.0297	0.9703	83.29
21.5	40,546,385	2,457,015	0.0606	0.9394	80.81
22.5	36,449,954	1,189,350	0.0326	0.9674	75.91
23.5	32,390,404	693,699	0.0214	0.9786	73.44
24.5	29,318,080	1,824,546	0.0622	0.9378	71.86
25.5	25,669,662	1,112,903	0.0434	0.9566	67.39
26.5	22,641,554	656,151	0.0290	0.9710	64.47
27.5	19,095,643	614,382	0.0322	0.9678	62.60
28.5	15,887,346	424,190	0.0267	0.9733	60.59
29.5	15,038,759	439,959	0.0293	0.9707	58.97
30.5	13,117,950	405,391	0.0309	0.9691	57.24
31.5	11,270,628	388,188	0.0344	0.9656	55.47
32.5	9,901,371	313,601	0.0317	0.9683	53.56
33.5	8,550,233	355,438	0.0416	0.9584	51.87
34.5	7,157,864	295,604	0.0413	0.9587	49.71
35.5	5,777,991	220,219	0.0381	0.9619	47.66
36.5	4,932,897	201,051	0.0408	0.9592	45.84
37.5	4,122,758	140,134	0.0340	0.9660	43.97
38.5	3,575,570	116,126	0.0325	0.9675	42.48

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1898-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,023,148	87,631	0.0290	0.9710	41.10
40.5	2,510,931	61,686	0.0246	0.9754	39.91
41.5	1,964,389	33,809	0.0172	0.9828	38.93
42.5	1,573,117	15,179	0.0096	0.9904	38.26
43.5	1,550,851	5,737	0.0037	0.9963	37.89
44.5	1,545,114	34,953	0.0226	0.9774	37.75
45.5	1,510,161	50,916	0.0337	0.9663	36.89
46.5	1,440,320	61,599	0.0428	0.9572	35.65
47.5	1,359,719	56,890	0.0418	0.9582	34.13
48.5	1,294,711	55,372	0.0428	0.9572	32.70
49.5	1,199,718	64,278	0.0536	0.9464	31.30
50.5	1,090,488	53,956	0.0495	0.9505	29.62
51.5	930,238	57,934	0.0623	0.9377	28.16
52.5	727,823	52,230	0.0718	0.9282	26.40
53.5	578,338	36,626	0.0633	0.9367	24.51
54.5	480,786	16,773	0.0349	0.9651	22.96
55.5	394,177	21,359	0.0542	0.9458	22.16
56.5	315,171	10,680	0.0339	0.9661	20.95
57.5	248,356	7,633	0.0307	0.9693	20.24
58.5	171,740	3,047	0.0177	0.9823	19.62
59.5	117,116		0.0000	1.0000	19.27
60.5	71,033		0.0000	1.0000	19.27
61.5	55,767		0.0000	1.0000	19.27
62.5	55,767		0.0000	1.0000	19.27
63.5	52,529		0.0000	1.0000	19.27
64.5	46,815		0.0000	1.0000	19.27
65.5	41,102		0.0000	1.0000	19.27
66.5	37,863		0.0000	1.0000	19.27
67.5	34,625		0.0000	1.0000	19.27
68.5	31,387		0.0000	1.0000	19.27
69.5	26,156		0.0000	1.0000	19.27
70.5	23,540		0.0000	1.0000	19.27
71.5	20,924		0.0000	1.0000	19.27
72.5	18,309		0.0000	1.0000	19.27
73.5	15,693		0.0000	1.0000	19.27
74.5	13,078		0.0000	1.0000	19.27
75.5	10,462	2,616	0.2500	0.7500	19.27
76.5	7,847		0.0000	1.0000	14.46
77.5	7,847		0.0000	1.0000	14.46
78.5	7,847		0.0000	1.0000	14.46

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1898-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	7,847		0.0000	1.0000	14.46
80.5	5,231		0.0000	1.0000	14.46
81.5	2,616	0	0.0000	1.0000	14.46
82.5	2,616	0	0.0000	1.0000	14.46
83.5	2,616		0.0000	1.0000	14.46
84.5	2,616		0.0000	1.0000	14.46
85.5	2,616		0.0000	1.0000	14.46
86.5	2,616		0.0000	1.0000	14.46
87.5	2,616		0.0000	1.0000	14.46
88.5	2,616		0.0000	1.0000	14.46
89.5	2,616		0.0000	1.0000	14.46
90.5	2,616		0.0000	1.0000	14.46
91.5	2,616		0.0000	1.0000	14.46
92.5	2,616		0.0000	1.0000	14.46
93.5	2,616		0.0000	1.0000	14.46
94.5	2,616		0.0000	1.0000	14.46
95.5					14.46

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1927-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	130,346,450		0.0000	1.0000	100.00
0.5	122,532,659	1,099,576	0.0090	0.9910	100.00
1.5	115,971,552	1,270,630	0.0110	0.9890	99.10
2.5	103,252,102	1,257,479	0.0122	0.9878	98.02
3.5	90,021,668	999,840	0.0111	0.9889	96.82
4.5	81,553,704	996,144	0.0122	0.9878	95.75
5.5	72,896,548	625,202	0.0086	0.9914	94.58
6.5	64,476,765	471,549	0.0073	0.9927	93.77
7.5	58,691,922	384,280	0.0065	0.9935	93.08
8.5	53,372,301	164,261	0.0031	0.9969	92.47
9.5	51,131,003	346,526	0.0068	0.9932	92.19
10.5	47,497,762	102,710	0.0022	0.9978	91.56
11.5	48,082,157	307,961	0.0064	0.9936	91.36
12.5	49,437,166	312,745	0.0063	0.9937	90.78
13.5	49,165,906	549,577	0.0112	0.9888	90.21
14.5	48,594,430	430,354	0.0089	0.9911	89.20
15.5	47,992,986	656,122	0.0137	0.9863	88.41
16.5	47,033,978	504,702	0.0107	0.9893	87.20
17.5	46,051,617	649,225	0.0141	0.9859	86.26
18.5	44,239,893	839,266	0.0190	0.9810	85.05
19.5	42,429,384	1,007,703	0.0238	0.9762	83.43
20.5	40,607,277	1,257,061	0.0310	0.9690	81.45
21.5	38,854,723	2,451,864	0.0631	0.9369	78.93
22.5	34,782,443	1,189,350	0.0342	0.9658	73.95
23.5	30,728,396	689,501	0.0224	0.9776	71.42
24.5	27,716,906	1,819,780	0.0657	0.9343	69.82
25.5	24,134,568	1,107,763	0.0459	0.9541	65.23
26.5	21,269,364	638,865	0.0300	0.9700	62.24
27.5	18,009,641	582,387	0.0323	0.9677	60.37
28.5	15,051,663	412,626	0.0274	0.9726	58.42
29.5	14,378,491	439,959	0.0306	0.9694	56.82
30.5	12,588,863	400,436	0.0318	0.9682	55.08
31.5	10,836,181	385,495	0.0356	0.9644	53.33
32.5	9,572,904	312,417	0.0326	0.9674	51.43
33.5	8,336,457	348,594	0.0418	0.9582	49.75
34.5	7,026,916	294,259	0.0419	0.9581	47.67
35.5	5,700,563	220,219	0.0386	0.9614	45.67
36.5	4,874,721	198,239	0.0407	0.9593	43.91
37.5	4,067,394	140,134	0.0345	0.9655	42.12
38.5	3,523,444	116,126	0.0330	0.9670	40.67

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1927-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,976,736	87,631	0.0294	0.9706	39.33
40.5	2,470,232	61,686	0.0250	0.9750	38.17
41.5	1,926,928	33,809	0.0175	0.9825	37.22
42.5	1,538,895	15,179	0.0099	0.9901	36.57
43.5	1,519,867	5,737	0.0038	0.9962	36.21
44.5	1,521,574	34,953	0.0230	0.9770	36.07
45.5	1,489,236	50,916	0.0342	0.9658	35.24
46.5	1,422,011	61,599	0.0433	0.9567	34.04
47.5	1,341,410	56,890	0.0424	0.9576	32.56
48.5	1,279,018	55,372	0.0433	0.9567	31.18
49.5	1,186,640	64,278	0.0542	0.9458	29.83
50.5	1,080,026	53,956	0.0500	0.9500	28.22
51.5	919,776	57,934	0.0630	0.9370	26.81
52.5	717,361	52,230	0.0728	0.9272	25.12
53.5	567,876	36,626	0.0645	0.9355	23.29
54.5	470,324	16,773	0.0357	0.9643	21.79
55.5	386,330	21,359	0.0553	0.9447	21.01
56.5	312,556	10,680	0.0342	0.9658	19.85
57.5	245,741	7,633	0.0311	0.9689	19.17
58.5	169,125	3,047	0.0180	0.9820	18.57
59.5	114,500		0.0000	1.0000	18.24
60.5	68,418		0.0000	1.0000	18.24
61.5	53,152		0.0000	1.0000	18.24
62.5	53,152		0.0000	1.0000	18.24
63.5	49,913		0.0000	1.0000	18.24
64.5	44,200		0.0000	1.0000	18.24
65.5	38,486		0.0000	1.0000	18.24
66.5	35,248		0.0000	1.0000	18.24
67.5	32,009		0.0000	1.0000	18.24
68.5	28,771		0.0000	1.0000	18.24
69.5	23,540		0.0000	1.0000	18.24
70.5	23,540		0.0000	1.0000	18.24
71.5	20,924		0.0000	1.0000	18.24
72.5	18,309		0.0000	1.0000	18.24
73.5	15,693		0.0000	1.0000	18.24
74.5	13,078		0.0000	1.0000	18.24
75.5	10,462	2,616	0.2500	0.7500	18.24
76.5	7,847		0.0000	1.0000	13.68
77.5	7,847		0.0000	1.0000	13.68
78.5	7,847		0.0000	1.0000	13.68

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

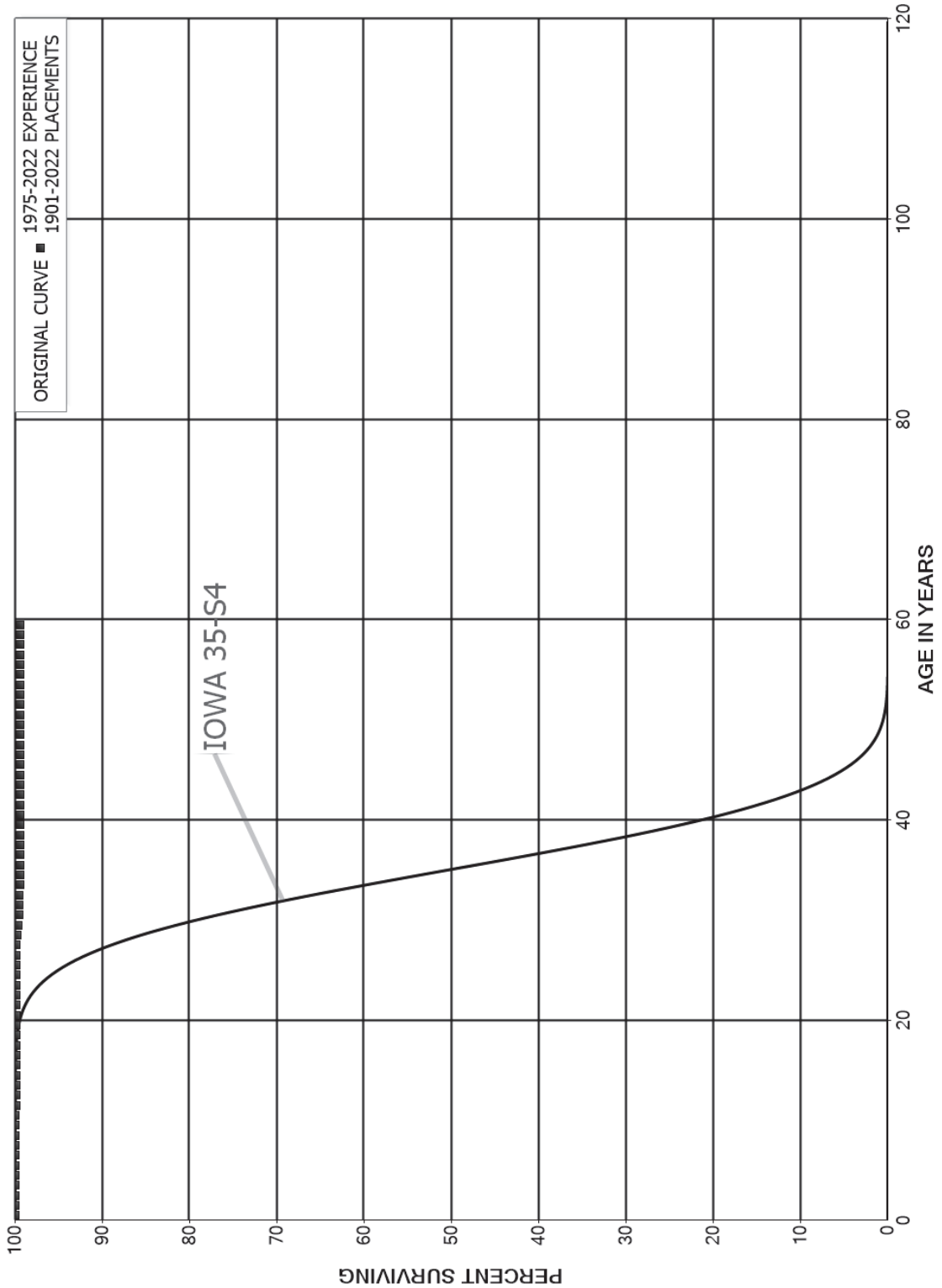
ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1927-2022 EXPERIENCE BAND 1998-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	7,847		0.0000	1.0000	13.68
80.5	5,231		0.0000	1.0000	13.68
81.5	2,616		0.0000	1.0000	13.68
82.5	2,616		0.0000	1.0000	13.68
83.5	2,616		0.0000	1.0000	13.68
84.5	2,616		0.0000	1.0000	13.68
85.5	2,616		0.0000	1.0000	13.68
86.5	2,616		0.0000	1.0000	13.68
87.5	2,616		0.0000	1.0000	13.68
88.5	2,616		0.0000	1.0000	13.68
89.5	2,616		0.0000	1.0000	13.68
90.5	2,616		0.0000	1.0000	13.68
91.5	2,616		0.0000	1.0000	13.68
92.5	2,616		0.0000	1.0000	13.68
93.5	2,616		0.0000	1.0000	13.68
94.5	2,616		0.0000	1.0000	13.68
95.5					13.68

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT
ACCOUNT 387.00 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,223,544		0.0000	1.0000	100.00
0.5	9,265,700		0.0000	1.0000	100.00
1.5	1,312,733		0.0000	1.0000	100.00
2.5	1,340,653		0.0000	1.0000	100.00
3.5	1,344,567		0.0000	1.0000	100.00
4.5	1,385,006		0.0000	1.0000	100.00
5.5	1,403,398		0.0000	1.0000	100.00
6.5	1,417,878		0.0000	1.0000	100.00
7.5	1,431,035		0.0000	1.0000	100.00
8.5	1,438,404		0.0000	1.0000	100.00
9.5	1,444,804	178	0.0001	0.9999	100.00
10.5	1,449,506	1,537	0.0011	0.9989	99.99
11.5	1,453,303	91	0.0001	0.9999	99.88
12.5	1,461,134		0.0000	1.0000	99.88
13.5	1,464,946		0.0000	1.0000	99.88
14.5	1,469,172		0.0000	1.0000	99.88
15.5	1,474,582		0.0000	1.0000	99.88
16.5	1,480,076		0.0000	1.0000	99.88
17.5	1,486,520		0.0000	1.0000	99.88
18.5	1,490,069		0.0000	1.0000	99.88
19.5	1,495,225		0.0000	1.0000	99.88
20.5	1,505,283		0.0000	1.0000	99.88
21.5	1,513,386		0.0000	1.0000	99.88
22.5	1,516,707		0.0000	1.0000	99.88
23.5	1,519,504	20	0.0000	1.0000	99.88
24.5	1,498,905		0.0000	1.0000	99.87
25.5	1,431,310		0.0000	1.0000	99.87
26.5	1,408,852		0.0000	1.0000	99.87
27.5	1,375,196	2,026	0.0015	0.9985	99.87
28.5	1,286,822	1,011	0.0008	0.9992	99.73
29.5	1,257,850	1,165	0.0009	0.9991	99.65
30.5	1,233,983	852	0.0007	0.9993	99.56
31.5	1,197,970	448	0.0004	0.9996	99.49
32.5	1,006,769	139	0.0001	0.9999	99.45
33.5	991,630	263	0.0003	0.9997	99.44
34.5	939,175		0.0000	1.0000	99.41
35.5	872,629	201	0.0002	0.9998	99.41
36.5	835,468		0.0000	1.0000	99.39
37.5	796,087		0.0000	1.0000	99.39
38.5	449,513		0.0000	1.0000	99.39

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	418,487		0.0000	1.0000	99.39
40.5	399,298	124	0.0003	0.9997	99.39
41.5	377,444		0.0000	1.0000	99.36
42.5	355,924		0.0000	1.0000	99.36
43.5	328,842		0.0000	1.0000	99.36
44.5	305,576		0.0000	1.0000	99.36
45.5	288,677		0.0000	1.0000	99.36
46.5	274,933		0.0000	1.0000	99.36
47.5	266,342		0.0000	1.0000	99.36
48.5	247,300		0.0000	1.0000	99.36
49.5	210,789		0.0000	1.0000	99.36
50.5	182,869		0.0000	1.0000	99.36
51.5	178,955		0.0000	1.0000	99.36
52.5	138,517		0.0000	1.0000	99.36
53.5	120,125		0.0000	1.0000	99.36
54.5	105,660		0.0000	1.0000	99.36
55.5	92,509		0.0000	1.0000	99.36
56.5	85,142		0.0000	1.0000	99.36
57.5	78,742		0.0000	1.0000	99.36
58.5	73,863		0.0000	1.0000	99.36
59.5	68,610		0.0000	1.0000	99.36
60.5	60,742	16	0.0003	0.9997	99.36
61.5	56,952	6	0.0001	0.9999	99.33
62.5	52,775	83	0.0016	0.9984	99.32
63.5	47,318	54	0.0012	0.9988	99.17
64.5	41,777	39	0.0009	0.9991	99.05
65.5	35,318	56	0.0016	0.9984	98.96
66.5	31,728	34	0.0011	0.9989	98.80
67.5	26,538	7	0.0003	0.9997	98.70
68.5	16,477	4	0.0002	0.9998	98.67
69.5	14,600	15	0.0010	0.9990	98.65
70.5	11,264		0.0000	1.0000	98.55
71.5	8,467	5	0.0006	0.9994	98.55
72.5	6,059	0	0.0001	0.9999	98.49
73.5	4,708	0	0.0001	0.9999	98.48
74.5	4,184		0.0000	1.0000	98.48
75.5	2,512	0	0.0001	0.9999	98.48
76.5	2,250	0	0.0000	1.0000	98.47
77.5	1,911		0.0000	1.0000	98.47
78.5	1,631		0.0000	1.0000	98.47

PUBLIC SERVICE ELECTRIC AND GAS
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

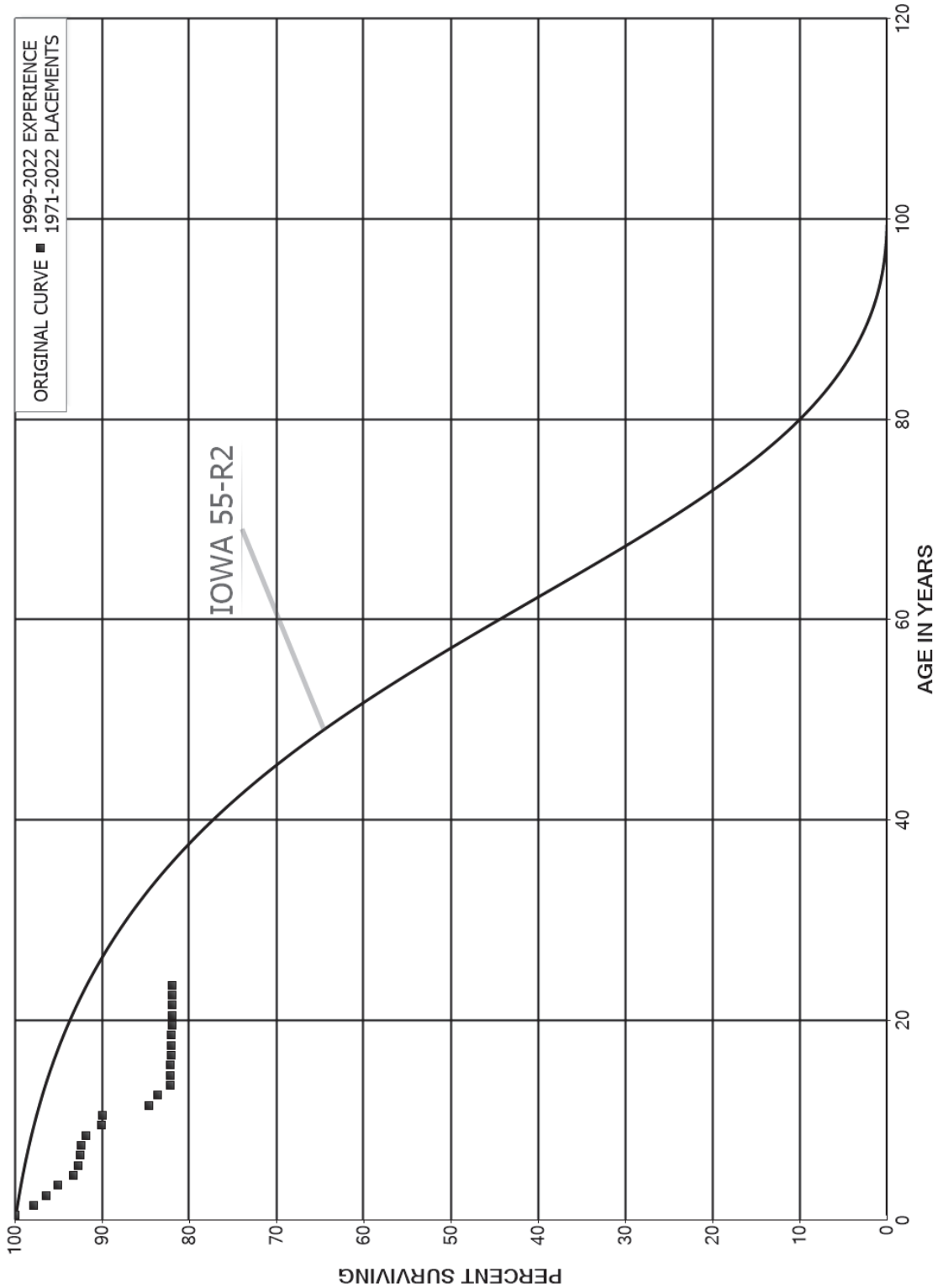
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1901-2022 EXPERIENCE BAND 1975-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,464		0.0000	1.0000	98.47
80.5	1,333		0.0000	1.0000	98.47
81.5	1,238		0.0000	1.0000	98.47
82.5	976		0.0000	1.0000	98.47
83.5	881		0.0000	1.0000	98.47
84.5	732		0.0000	1.0000	98.47
85.5	601		0.0000	1.0000	98.47
86.5	524		0.0000	1.0000	98.47
87.5	488		0.0000	1.0000	98.47
88.5	375		0.0000	1.0000	98.47
89.5	131		0.0000	1.0000	98.47
90.5	131		0.0000	1.0000	98.47
91.5	54		0.0000	1.0000	98.47
92.5	18		0.0000	1.0000	98.47
93.5					98.47

ELECTRIC, GAS AND COMMON PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC, GAS AND COMMON PLANT
ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC, GAS AND COMMON PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2022 EXPERIENCE BAND 1999-2022

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	130,977,659	25	0.0000	1.0000	100.00
0.5	137,316,997	2,962,640	0.0216	0.9784	100.00
1.5	136,925,741	2,017,533	0.0147	0.9853	97.84
2.5	136,011,823	1,915,555	0.0141	0.9859	96.40
3.5	109,837,200	2,001,454	0.0182	0.9818	95.04
4.5	85,874,723	557,667	0.0065	0.9935	93.31
5.5	71,292,829	189,164	0.0027	0.9973	92.71
6.5	65,211,989	53,272	0.0008	0.9992	92.46
7.5	58,264,432	367,559	0.0063	0.9937	92.38
8.5	56,564,206	1,061,624	0.0188	0.9812	91.80
9.5	49,847,185	92,576	0.0019	0.9981	90.08
10.5	49,252,762	2,885,612	0.0586	0.9414	89.91
11.5	39,724,360	503,624	0.0127	0.9873	84.64
12.5	37,141,297	634,960	0.0171	0.9829	83.57
13.5	36,452,027		0.0000	1.0000	82.14
14.5	36,023,315		0.0000	1.0000	82.14
15.5	35,421,130	19,452	0.0005	0.9995	82.14
16.5	34,488,937	8,743	0.0003	0.9997	82.10
17.5	33,542,579	2,228	0.0001	0.9999	82.08
18.5	130,916,305	271,961	0.0021	0.9979	82.07
19.5	110,510,253		0.0000	1.0000	81.90
20.5	107,861,967		0.0000	1.0000	81.90
21.5	105,556,206		0.0000	1.0000	81.90
22.5	105,454,356		0.0000	1.0000	81.90
23.5					81.90

PART VIII. NET SALVAGE STATISTICS

ELECTRIC PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	145,315	138,704	95	29,596	20	109,108-	75-
1978	83,358	46,434	56		0	46,434-	56-
1979	52,118	39,050	75	1,214	2	37,836-	73-
1980	47,553	92,853	195		0	92,853-	195-
1981	19,313	40,183	208	38	0	40,145-	208-
1982	131,014	93,979	72	50	0	93,929-	72-
1983	54,684	31,951	58	3,811-	7-	35,762-	65-
1984	28,153	11,754	42	4,440	16	7,314-	26-
1985	132,620	46,972	35	117-	0	47,089-	36-
1986	228,313	41,757	18	367	0	41,390-	18-
1987	26,461	1,063	4		0	1,063-	4-
1988	62,514	35,882	57		0	35,882-	57-
1989	35,969	238,846	664	48,231	134	190,615-	530-
1990	55,762	344,831	618	4,615	8	340,216-	610-
1991	395,306	368,728	93	2,149	1	366,578-	93-
1992	530,822	1,052,723	198	2,264-	0	1,054,987-	199-
1993	137,928	176,291	128		0	176,291-	128-
1994	487,804	331,722	68		0	331,722-	68-
1995	458,512	160,599	35	21,124-	5-	181,723-	40-
1996	42,062	22,919	54	769-	2-	23,688-	56-
1997	402,082	169,138	42		0	169,138-	42-
1998		440,621				440,621-	
1999		47,450				47,450-	
2000		457,317				457,317-	
2001	243,717	307,407	126		0	307,407-	126-
2002	23,467	309,680			0	309,680-	
2003	276,030	133,520	48		0	133,520-	48-
2004	6,102	38,548	632		0	38,548-	632-
2005	46,185	84,825	184		0	84,825-	184-
2006		41,195				41,195-	
2007	29,046	135,575	467		0	135,575-	467-
2008		414,379				414,379-	
2009		15,883		11,814		4,069-	
2010		448,624				448,624-	
2011		290,165-				290,165	
2012		65,512				65,512-	
2013		498,391				498,391-	
2014		97,439				97,439-	
2015		48,599				48,599-	
2016		3,303,363				3,303,363-	
2017		867,303		29,368-		896,671-	
2018		7,762,683		39,421		7,723,262-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	976,099	1,556,168	159	111,272	11	1,444,896-	148-
2020	9,565,494	1,290,301	13	98,724	1	1,191,577-	12-
2021	964,839	2,344,276	243	252,887	26	2,091,389-	217-
2022	1,006,794	1,036,067	103	342,101	34	693,966-	69-
TOTAL	16,695,435	24,941,340	149	889,466	5	24,051,874-	144-
THREE-YEAR MOVING AVERAGES							
77-79	93,597	74,729	80	10,270	11	64,459-	69-
78-80	61,010	59,446	97	405	1	59,041-	97-
79-81	39,661	57,362	145	417	1	56,945-	144-
80-82	65,960	75,672	115	29	0	75,642-	115-
81-83	68,337	55,371	81	1,241-	2-	56,612-	83-
82-84	71,284	45,895	64	226	0	45,668-	64-
83-85	71,819	30,226	42	171	0	30,055-	42-
84-86	129,695	33,494	26	1,563	1	31,931-	25-
85-87	129,131	29,931	23	83	0	29,847-	23-
86-88	105,763	26,234	25	122	0	26,112-	25-
87-89	41,648	91,930	221	16,077	39	75,853-	182-
88-90	51,415	206,520	402	17,615	34	188,904-	367-
89-91	162,346	317,468	196	18,332	11	299,137-	184-
90-92	327,297	588,761	180	1,500	0	587,261-	179-
91-93	354,685	532,580	150	38-	0	532,619-	150-
92-94	385,518	520,245	135	755-	0	521,000-	135-
93-95	361,415	222,870	62	7,041-	2-	229,912-	64-
94-96	329,459	171,747	52	7,298-	2-	179,044-	54-
95-97	300,885	117,552	39	7,298-	2-	124,850-	41-
96-98	148,048	210,893	142	256-	0	211,149-	143-
97-99	134,027	219,070	163		0	219,070-	163-
98-00		315,129				315,129-	
99-01	81,239	270,725	333		0	270,725-	333-
00-02	89,061	358,135	402		0	358,135-	402-
01-03	181,071	250,202	138		0	250,202-	138-
02-04	101,866	160,583	158		0	160,583-	158-
03-05	109,439	85,631	78		0	85,631-	78-
04-06	17,429	54,856	315		0	54,856-	315-
05-07	25,077	87,199	348		0	87,199-	348-
06-08	9,682	197,050			0	197,050-	
07-09	9,682	188,612		3,938	41	184,674-	
08-10		292,962		3,938		289,024-	
09-11		58,114		3,938		54,176-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12		74,657				74,657-	
11-13		91,246				91,246-	
12-14		220,448				220,448-	
13-15		214,810				214,810-	
14-16		1,149,800				1,149,800-	
15-17		1,406,422		9,789-		1,416,211-	
16-18		3,977,783		3,351		3,974,432-	
17-19	325,366	3,395,385		40,442	12	3,354,943-	
18-20	3,513,864	3,536,384	101	83,139	2	3,453,245-	98-
19-21	3,835,477	1,730,248	45	154,294	4	1,575,954-	41-
20-22	3,845,709	1,556,881	40	231,237	6	1,325,644-	34-
FIVE-YEAR AVERAGE							
18-22	2,502,645	2,797,899	112	168,881	7	2,629,018-	105-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	199,673	148,182	74	279,248	140	131,066	66
1978	260,405	81,898	31	79,605	31	2,293-	1-
1979	231,764	17,286-	7-	11,082	5	28,368	12
1980	843,875	212,073	25	39,817	5	172,256-	20-
1981	523,316	96,885	19	168,312	32	71,427	14
1982	10,633	69,333	652	284,817		215,484	
1983	999,245	365,941	37	5,716	1	360,225-	36-
1984	306,593	126,237	41	1,253-	0	127,490-	42-
1985	1,279,635	359,954	28	17,629-	1-	377,583-	30-
1986	1,408,720	436,220	31	5,068	0	431,152-	31-
1987	1,759,252	439,699	25	5,337	0	434,362-	25-
1988	738,413	604,222	82	41,258	6	562,964-	76-
1989	1,968,696	865,782	44	3,856	0	861,926-	44-
1990	1,432,136	1,539,100	107	276,819	19	1,262,281-	88-
1991	2,760,752	2,076,516	75	527	0	2,075,990-	75-
1992	2,039,047	2,382,126	117	3,551	0	2,378,574-	117-
1993	3,094,091	1,930,057	62	551,545	18	1,378,513-	45-
1994	3,097,354	2,001,312	65	471,609-	15-	2,472,921-	80-
1995	3,586,971	1,804,164	50	427,593-	12-	2,231,757-	62-
1996	3,271,650	1,304,111	40	272,325-	8-	1,576,437-	48-
1997	212,785	1,107,364	520	44,018-	21-	1,151,382-	541-
1998	114,797	522,897	455	634,308	553	111,411	97
1999	77,232	158,381	205	6,380	8	152,001-	197-
2000	30,007	600,360		20,000	67	580,360-	
2001	4,672,168	588,954	13		0	588,954-	13-
2002	614,275	991,556	161	40,573	7	950,983-	155-
2003	2,473,418	545,722	22	69,437	3	476,285-	19-
2004	247,441	691,772	280	122,806	50	568,966-	230-
2005	1,014,600	2,751,424	271	285,408	28	2,466,016-	243-
2006	558,143	1,461,681	262	421,046	75	1,040,635-	186-
2007	1,663,502	1,797,325	108	306,453	18	1,490,872-	90-
2008	712,159	1,748,325	245	273,196	38	1,475,129-	207-
2009	1,210,276	1,958,604	162	4,193,463	346	2,234,859	185
2010	55,486	2,261,826		3,886,089		1,624,262	
2011	1,306,994	1,745,427	134	4,100,229	314	2,354,802	180
2012	15,610,685	2,597,811	17	2,738,714	18	140,904	1
2013	7,605,257	2,164,738	28	2,137,651	28	27,087-	0
2014	7,645,971	3,303,849	43	1,271,095	17	2,032,753-	27-
2015	13,160,784	9,425,392	72	1,396,126	11	8,029,266-	61-
2016	35,889,973	21,128,732	59	2,858,336	8	18,270,396-	51-
2017	29,581,747	9,028,938	31	284,447	1	8,744,491-	30-
2018	69,209,788	11,919,718	17	2,363,270	3	9,556,448-	14-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	47,682,879	6,656,960	14	13,049,045	27	6,392,085	13
2020	10,301,839	12,000,961	116	180,956	2	11,820,004-	115-
2021	24,522,600	4,561,605	19	543,749	2	4,017,856-	16-
2022	23,235,649	9,745,262	42	480,428	2	9,264,834-	40-
TOTAL	329,222,677	128,292,110	39	42,185,336	13	86,106,774-	26-
THREE-YEAR MOVING AVERAGES							
77-79	230,614	70,931	31	123,312	53	52,380	23
78-80	445,348	92,228	21	43,501	10	48,727-	11-
79-81	532,985	97,224	18	73,070	14	24,154-	5-
80-82	459,275	126,097	27	164,315	36	38,218	8
81-83	511,065	177,386	35	152,948	30	24,438-	5-
82-84	438,824	187,170	43	96,427	22	90,744-	21-
83-85	861,824	284,044	33	4,389-	1-	288,433-	33-
84-86	998,316	307,470	31	4,605-	0	312,075-	31-
85-87	1,482,536	411,958	28	2,408-	0	414,366-	28-
86-88	1,302,128	493,380	38	17,221	1	476,159-	37-
87-89	1,488,787	636,568	43	16,817	1	619,751-	42-
88-90	1,379,748	1,003,035	73	107,311	8	895,724-	65-
89-91	2,053,861	1,493,800	73	93,734	5	1,400,066-	68-
90-92	2,077,312	1,999,247	96	93,632	5	1,905,615-	92-
91-93	2,631,297	2,129,566	81	185,207	7	1,944,359-	74-
92-94	2,743,497	2,104,498	77	27,829	1	2,076,669-	76-
93-95	3,259,472	1,911,844	59	115,886-	4-	2,027,730-	62-
94-96	3,318,658	1,703,196	51	390,509-	12-	2,093,705-	63-
95-97	2,357,136	1,405,213	60	247,979-	11-	1,653,192-	70-
96-98	1,199,744	978,124	82	105,988	9	872,136-	73-
97-99	134,938	596,214	442	198,890	147	397,324-	294-
98-00	74,012	427,213	577	220,229	298	206,983-	280-
99-01	1,593,136	449,232	28	8,793	1	440,438-	28-
00-02	1,772,150	726,957	41	20,191	1	706,766-	40-
01-03	2,586,620	708,744	27	36,670	1	672,074-	26-
02-04	1,111,711	743,016	67	77,605	7	665,411-	60-
03-05	1,245,153	1,329,639	107	159,217	13	1,170,422-	94-
04-06	606,728	1,634,959	269	276,420	46	1,358,539-	224-
05-07	1,078,748	2,003,477	186	337,636	31	1,665,841-	154-
06-08	977,934	1,669,110	171	333,565	34	1,335,545-	137-
07-09	1,195,312	1,834,751	153	1,591,037	133	243,714-	20-
08-10	659,307	1,989,585	302	2,784,249	422	794,664	121
09-11	857,586	1,988,619	232	4,059,927	473	2,071,308	242

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	5,657,722	2,201,688	39	3,575,011	63	1,373,323	24
11-13	8,174,312	2,169,325	27	2,992,198	37	822,873	10
12-14	10,287,304	2,688,799	26	2,049,153	20	639,646-	6-
13-15	9,470,671	4,964,659	52	1,601,624	17	3,363,035-	36-
14-16	18,898,909	11,285,991	60	1,841,852	10	9,444,138-	50-
15-17	26,210,835	13,194,354	50	1,512,970	6	11,681,384-	45-
16-18	44,893,836	14,025,796	31	1,835,351	4	12,190,445-	27-
17-19	48,824,805	9,201,872	19	5,232,254	11	3,969,618-	8-
18-20	42,398,169	10,192,547	24	5,197,757	12	4,994,789-	12-
19-21	27,502,440	7,739,842	28	4,591,250	17	3,148,592-	11-
20-22	19,353,363	8,769,276	45	401,711	2	8,367,565-	43-
FIVE-YEAR AVERAGE							
18-22	34,990,551	8,976,901	26	3,323,490	9	5,653,411-	16-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	1,550,526	1,774,916	114	666,793	43	1,108,123-	71-
1978	1,095,276	1,967,983	180	774,883	71	1,193,100-	109-
1979	1,152,503	2,050,029	178	932,674	81	1,117,355-	97-
1980	1,264,093	2,323,496	184	724,311	57	1,599,185-	127-
1981	1,413,689	2,536,768	179	980,600	69	1,556,168-	110-
1982	1,293,843	2,143,979	166	1,061,921	82	1,082,058-	84-
1983	1,319,252	2,298,518	174	1,003,907	76	1,294,611-	98-
1984	1,327,661	3,569,850	269	983,393	74	2,586,457-	195-
1985	1,514,097	5,248,002	347	1,103,240	73	4,144,762-	274-
1986	1,845,284	6,077,378	329	1,404,439	76	4,672,939-	253-
1987	1,915,115	4,193,276	219	1,565,517	82	2,627,759-	137-
1988	1,790,008	4,336,483	242	1,244,249	70	3,092,234-	173-
1989	1,757,026	4,392,791	250	1,311,478	75	3,081,313-	175-
1990	1,947,720	419,989	22	56,561	3	363,428-	19-
1991	1,537,158	968,906	63	1,172,534	76	203,628	13
1992	1,784,143	2,034,494	114	1,856,994	104	177,500-	10-
1993	1,616,688	3,076,292	190	433,053	27	2,643,239-	163-
1994	1,303,801	2,288,228	176	1,330,743	102	957,485-	73-
1995	1,337,646	2,632,822	197	1,853,558	139	779,264-	58-
1996	1,333,088	2,286,728	172	2,189,552	164	97,176-	7-
1997	1,154,621	2,087,159	181	1,815,713	157	271,446-	24-
1998	927,749	1,307,835	141	1,567,608	169	259,773	28
1999	116,959	1,557,646			0	1,557,646-	
2000	422,907	1,306,901	309		0	1,306,901-	309-
2001	830,121	930,258	112		0	930,258-	112-
2002	2,539,367	2,767,432	109		0	2,767,432-	109-
2003	669,662	6,176,732	922		0	6,176,732-	922-
2004	567,132	8,461,021			0	8,461,021-	
2005	647,486	6,675,958			0	6,675,958-	
2006	689,712	8,313,010			0	8,313,010-	
2007	740,376	9,353,214			0	9,353,214-	
2008	848,577	11,945,613			0	11,945,613-	
2009	295,347-	11,442,848			0	11,442,848-	
2010	643,346	16,792,571			0	16,792,571-	
2011	1,108,043	16,094,878			0	16,094,878-	
2012	1,612,143	19,004,463			0	19,004,463-	
2013	1,010,675	10,167,523			0	10,167,523-	
2014	922,980	10,628,718			0	10,628,718-	
2015	800,203	12,885,864		84,887	11	12,800,977-	
2016	1,398,892	14,550,879			0	14,550,879-	
2017	930,480	17,450,911		666	0	17,450,246-	
2018	880,819	29,164,045		13,109	1	29,150,937-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	923,495	15,588,295		769,589	83	14,818,706-	
2020	745,657	19,332,427		507,357	68	18,825,071-	
2021	875,655	17,777,026		1,963,822	224	15,813,204-	
2022	730,594	19,434,433		1,892,194	259	17,542,238-	
TOTAL	52,540,921	347,818,589	662	31,265,345	60	316,553,244-	602-
THREE-YEAR MOVING AVERAGES							
77-79	1,266,102	1,930,976	153	791,450	63	1,139,526-	90-
78-80	1,170,624	2,113,836	181	810,623	69	1,303,213-	111-
79-81	1,276,762	2,303,431	180	879,195	69	1,424,236-	112-
80-82	1,323,875	2,334,748	176	922,277	70	1,412,470-	107-
81-83	1,342,261	2,326,422	173	1,015,476	76	1,310,946-	98-
82-84	1,313,585	2,670,782	203	1,016,407	77	1,654,375-	126-
83-85	1,387,003	3,705,457	267	1,030,180	74	2,675,277-	193-
84-86	1,562,347	4,965,077	318	1,163,691	74	3,801,386-	243-
85-87	1,758,165	5,172,885	294	1,357,732	77	3,815,153-	217-
86-88	1,850,136	4,869,046	263	1,404,735	76	3,464,311-	187-
87-89	1,820,716	4,307,517	237	1,373,748	75	2,933,769-	161-
88-90	1,831,585	3,049,754	167	870,763	48	2,178,992-	119-
89-91	1,747,301	1,927,229	110	846,858	48	1,080,371-	62-
90-92	1,756,340	1,141,130	65	1,028,696	59	112,434-	6-
91-93	1,645,996	2,026,564	123	1,154,194	70	872,371-	53-
92-94	1,568,211	2,466,338	157	1,206,930	77	1,259,408-	80-
93-95	1,419,379	2,665,781	188	1,205,785	85	1,459,996-	103-
94-96	1,324,845	2,402,593	181	1,791,284	135	611,308-	46-
95-97	1,275,118	2,335,570	183	1,952,941	153	382,629-	30-
96-98	1,138,486	1,893,907	166	1,857,624	163	36,283-	3-
97-99	733,110	1,650,880	225	1,127,774	154	523,106-	71-
98-00	489,205	1,390,794	284	522,536	107	868,258-	177-
99-01	456,662	1,264,935	277		0	1,264,935-	277-
00-02	1,264,131	1,668,197	132		0	1,668,197-	132-
01-03	1,346,383	3,291,474	244		0	3,291,474-	244-
02-04	1,258,720	5,801,728	461		0	5,801,728-	461-
03-05	628,093	7,104,570			0	7,104,570-	
04-06	634,777	7,816,663			0	7,816,663-	
05-07	692,525	8,114,061			0	8,114,061-	
06-08	759,555	9,870,612			0	9,870,612-	
07-09	431,202	10,913,892			0	10,913,892-	
08-10	398,859	13,393,677			0	13,393,677-	
09-11	485,347	14,776,765			0	14,776,765-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	1,121,177	17,297,304			0	17,297,304-	
11-13	1,243,620	15,088,955			0	15,088,955-	
12-14	1,181,933	13,266,901			0	13,266,901-	
13-15	911,286	11,227,368		28,296	3	11,199,072-	
14-16	1,040,692	12,688,487		28,296	3	12,660,191-	
15-17	1,043,192	14,962,551		28,518	3	14,934,034-	
16-18	1,070,064	20,388,612		4,591	0	20,384,020-	
17-19	911,598	20,734,417		261,121	29	20,473,296-	
18-20	849,990	21,361,589		430,018	51	20,931,571-	
19-21	848,269	17,565,916		1,080,256	127	16,485,660-	
20-22	783,969	18,847,962		1,454,458	186	17,393,504-	
FIVE-YEAR AVERAGE							
18-22	831,244	20,259,245		1,029,214	124	19,230,031-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	1,502,708	1,407,661	94	690,816	46	716,845-	48-
1978	1,606,974	1,640,936	102	711,851	44	929,085-	58-
1979	1,828,277	1,804,374	99	896,926	49	907,448-	50-
1980	2,198,718	2,004,261	91	1,128,132	51	876,129-	40-
1981	1,967,220	2,243,820	114	1,012,882	51	1,230,938-	63-
1982	2,040,987	4,407,111	216	723,038	35	3,684,073-	181-
1983	2,527,154	4,768,187	189	809,751	32	3,958,436-	157-
1984	2,501,862	3,683,379	147	767,924	31	2,915,455-	117-
1985	2,977,421	4,255,645	143	917,466	31	3,338,179-	112-
1986	2,478,076	4,465,917	180	998,917	40	3,467,000-	140-
1987	3,153,010	2,996,192	95	1,159,807	37	1,836,385-	58-
1988	3,198,816	2,704,462	85	1,209,229	38	1,495,233-	47-
1989	2,970,718	2,535,601	85	1,234,671	42	1,300,930-	44-
1990	3,200,844	444,166	14	130,165	4	314,002-	10-
1991	3,159,037	66,709	2	396,522	13	329,814	10
1992	2,873,784	404,154	14	465,564	16	61,410	2
1993	2,683,552	1,658,698	62	846,912	32	811,786-	30-
1994	2,237,877	4,918,690	220	838,394	37	4,080,297-	182-
1995	2,049,888	5,586,425	273	1,634,353	80	3,952,072-	193-
1996	1,716,165	4,391,964	256	875,332	51	3,516,631-	205-
1997	950,350	3,928,339	413	701,144	74	3,227,195-	340-
1998	587,442	4,424,357	753	699,691	119	3,724,666-	634-
1999	12,508	1,393,201			0	1,393,201-	
2000	329,352	2,730,986	829		0	2,730,986-	829-
2001	415,387	1,968,817	474		0	1,968,817-	474-
2002	757,477	2,394,681	316	158,515	21	2,236,166-	295-
2003	246,730	1,667,683	676	192,872	78	1,474,812-	598-
2004	399,199	2,527,024	633	347,785	87	2,179,239-	546-
2005	209,580	1,949,368	930	321,566	153	1,627,802-	777-
2006	295,180	2,706,396	917	580,702	197	2,125,694-	720-
2007	206,232	2,713,185		806,287	391	1,906,898-	925-
2008	101,110	3,750,902		616,138	609	3,134,764-	
2009	12,040,942	3,884,550	32		0	3,884,550-	32-
2010	4,412,856	5,044,602	114	1,937,652	44	3,106,950-	70-
2011	4,588,963	5,239,497	114	1,724,335	38	3,515,162-	77-
2012	13,122,659	5,230,177	40	2,774	0	5,227,403-	40-
2013	9,244,861	2,673,272	29	1,140	0	2,672,132-	29-
2014	7,878,415	3,121,090	40	192	0	3,120,898-	40-
2015	11,149,518	3,459,815	31	1,182,766	11	2,277,049-	20-
2016	22,600,876	3,925,418	17	393,892	2	3,531,526-	16-
2017	27,641,509	5,872,515	21	424,723	2	5,447,792-	20-
2018	19,122,984	7,022,027	37	627,990	3	6,394,036-	33-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	14,676,098	3,042,692	21	638,655	4	2,404,037-	16-
2020	16,444,597	3,501,308	21	642,190	4	2,859,118-	17-
2021	19,350,137	3,723,143	19	1,172,499	6	2,550,644-	13-
2022	19,168,272	4,691,230	24	1,059,029	6	3,632,200-	19-
TOTAL	254,826,321	148,974,628	58	31,681,188	12	117,293,440-	46-
THREE-YEAR MOVING AVERAGES							
77-79	1,645,986	1,617,657	98	766,531	47	851,126-	52-
78-80	1,877,990	1,816,524	97	912,303	49	904,221-	48-
79-81	1,998,072	2,017,485	101	1,012,647	51	1,004,838-	50-
80-82	2,068,975	2,885,064	139	954,684	46	1,930,380-	93-
81-83	2,178,454	3,806,373	175	848,557	39	2,957,816-	136-
82-84	2,356,668	4,286,226	182	766,904	33	3,519,321-	149-
83-85	2,668,812	4,235,737	159	831,714	31	3,404,023-	128-
84-86	2,652,453	4,134,980	156	894,769	34	3,240,211-	122-
85-87	2,869,502	3,905,918	136	1,025,397	36	2,880,521-	100-
86-88	2,943,301	3,388,857	115	1,122,651	38	2,266,206-	77-
87-89	3,107,515	2,745,418	88	1,201,236	39	1,544,183-	50-
88-90	3,123,460	1,894,743	61	858,022	27	1,036,722-	33-
89-91	3,110,200	1,015,492	33	587,119	19	428,373-	14-
90-92	3,077,888	305,010	10	330,750	11	25,741	1
91-93	2,905,458	709,854	24	569,666	20	140,188-	5-
92-94	2,598,404	2,327,181	90	716,956	28	1,610,224-	62-
93-95	2,323,772	4,054,605	174	1,106,553	48	2,948,052-	127-
94-96	2,001,310	4,965,693	248	1,116,026	56	3,849,667-	192-
95-97	1,572,134	4,635,576	295	1,070,276	68	3,565,300-	227-
96-98	1,084,653	4,248,220	392	758,722	70	3,489,498-	322-
97-99	516,767	3,248,632	629	466,945	90	2,781,687-	538-
98-00	309,767	2,849,515	920	233,230	75	2,616,284-	845-
99-01	252,415	2,031,001	805		0	2,031,001-	805-
00-02	500,738	2,364,828	472	52,838	11	2,311,990-	462-
01-03	473,198	2,010,394	425	117,129	25	1,893,265-	400-
02-04	467,802	2,196,463	470	233,057	50	1,963,406-	420-
03-05	285,169	2,048,025	718	287,408	101	1,760,618-	617-
04-06	301,319	2,394,263	795	416,684	138	1,977,579-	656-
05-07	236,997	2,456,316		569,518	240	1,886,798-	796-
06-08	200,841	3,056,828		667,709	332	2,389,119-	
07-09	4,116,095	3,449,546	84	474,142	12	2,975,404-	72-
08-10	5,518,303	4,226,685	77	851,263	15	3,375,421-	61-
09-11	7,014,254	4,722,883	67	1,220,662	17	3,502,221-	50-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	7,374,826	5,171,425	70	1,221,587	17	3,949,838-	54-
11-13	8,985,494	4,380,982	49	576,083	6	3,804,899-	42-
12-14	10,081,979	3,674,846	36	1,369	0	3,673,478-	36-
13-15	9,424,265	3,084,726	33	394,700	4	2,690,027-	29-
14-16	13,876,270	3,502,108	25	525,617	4	2,976,491-	21-
15-17	20,463,968	4,419,249	22	667,127	3	3,752,122-	18-
16-18	23,121,790	5,606,653	24	482,202	2	5,124,451-	22-
17-19	20,480,197	5,312,411	26	563,790	3	4,748,622-	23-
18-20	16,747,893	4,522,009	27	636,278	4	3,885,730-	23-
19-21	16,823,611	3,422,381	20	817,781	5	2,604,600-	15-
20-22	18,321,002	3,971,893	22	957,906	5	3,013,988-	16-
FIVE-YEAR AVERAGE							
18-22	17,752,418	4,396,080	25	828,073	5	3,568,007-	20-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	50,612	23,130	46	30,931	61	7,801	15
1978	8,979	49,953	556	25,883	288	24,070-	268-
1979	30,875	28,735	93	11,084-	36-	39,819-	129-
1980	50,217	41,585	83	3,065-	6-	44,650-	89-
1981	15,567	36,149	232	6,331	41	29,818-	192-
1982	9,538	48,458	508	16,157	169	32,301-	339-
1983	5,096	53,993		11,887	233	42,106-	826-
1984	17,165	28,077	164	4,748	28	23,329-	136-
1985	15,425	32,809	213	23,454	152	9,355-	61-
1986	26,151	34,909	133	13,391	51	21,518-	82-
1987	26,952	29,167	108	199,551	740	170,384	632
1988	78,697	17,774	23	150,557	191	132,783	169
1989	46,999	16,404	35	26,253	56	9,849	21
1990	198,081	40,742	21	24,901	13	15,841-	8-
1991	37,115	14,765	40	75,176	203	60,411	163
1992	164,150	442-	0	17,556	11	17,998	11
1993	191,138	12,432-	7-	12,557	7	24,988	13
1994	45,931	1,274	3	37,596	82	36,322	79
1995	43,544		0	2,254	5	2,254	5
1996	18,635	54,315	291	42,792	230	11,523-	62-
1997	980	24,000		71,179		47,180	
1998	7,599	124,096		37,972	500	86,124-	
1999		277,949				277,949-	
2000		16,822		5,688		11,134-	
2001		4,604				4,604-	
2002	16	9,723		10,575		852	
2003	715	110,771		14,074		96,696-	
2004		103,664		25,399		78,266-	
2005		63,940		23,373		40,567-	
2006	71	37,748		42,000		4,252	
2007		187,218		59,059		128,159-	
2008	2	142,443		40,997		101,446-	
2009	61,238-	84,529	138-		0	84,529-	138
2010	1	105,149			0	105,149-	
2011	1,374	89,653			0	89,653-	
2012	652	1,088,789			0	1,088,789-	
2013	321	159,342			0	159,342-	
2014	418	126,361			0	126,361-	
2015	229	125,415		24	11	125,391-	
2016	5,236	165,506			0	165,506-	
2017		139,435				139,435-	
2018		2,401,610				2,401,610-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	6,627	282,859		35,206	531	247,653-	
2020	290	106,041		23,337		82,704-	
2021	1,953	115,849		91,749		24,101-	
2022		360,687		89,220		271,467-	
TOTAL	1,046,111	6,993,568	669	1,277,679	122	5,715,889-	546-
THREE-YEAR MOVING AVERAGES							
77-79	30,155	33,939	113	15,243	51	18,696-	62-
78-80	30,024	40,091	134	3,911	13	36,180-	121-
79-81	32,220	35,490	110	2,606-	8-	38,096-	118-
80-82	25,107	42,064	168	6,474	26	35,590-	142-
81-83	10,067	46,200	459	11,458	114	34,742-	345-
82-84	10,600	43,509	410	10,931	103	32,579-	307-
83-85	12,562	38,293	305	13,363	106	24,930-	198-
84-86	19,580	31,932	163	13,864	71	18,067-	92-
85-87	22,843	32,295	141	78,799	345	46,504	204
86-88	43,933	27,283	62	121,166	276	93,883	214
87-89	50,883	21,115	41	125,454	247	104,339	205
88-90	107,926	24,973	23	67,237	62	42,264	39
89-91	94,065	23,970	25	42,110	45	18,139	19
90-92	133,115	18,355	14	39,211	29	20,856	16
91-93	130,801	631	0	35,096	27	34,466	26
92-94	133,739	3,866-	3-	22,570	17	26,436	20
93-95	93,538	3,719-	4-	17,469	19	21,188	23
94-96	36,037	18,530	51	27,548	76	9,018	25
95-97	21,053	26,105	124	38,742	184	12,637	60
96-98	9,071	67,470	744	50,648	558	16,822-	185-
97-99	2,860	142,015		36,384		105,631-	
98-00	2,533	139,623		14,553	575	125,069-	
99-01		99,792		1,896		97,896-	
00-02	5	10,383		5,421		4,962-	
01-03	244	41,699		8,216		33,483-	
02-04	244	74,719		16,683		58,037-	
03-05	238	92,792		20,949		71,843-	
04-06	24	68,451		30,257		38,194-	
05-07	24	96,302		41,477		54,825-	
06-08	24	122,470		47,352		75,118-	
07-09	20,412-	138,063	676-	33,352	163-	104,711-	513
08-10	20,412-	110,707	542-	13,666	67-	97,041-	475
09-11	19,954-	93,110	467-		0	93,110-	467

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	676	427,864			0	427,864-	
11-13	782	445,928			0	445,928-	
12-14	463	458,164			0	458,164-	
13-15	322	137,039		8	3	137,031-	
14-16	1,961	139,094		8	0	139,086-	
15-17	1,822	143,452		8	0	143,444-	
16-18	1,745	902,183			0	902,183-	
17-19	2,209	941,301		11,735	531	929,566-	
18-20	2,306	930,170		19,514	846	910,656-	
19-21	2,957	168,250		50,097		118,153-	
20-22	748	194,193		68,102		126,091-	
FIVE-YEAR AVERAGE							
18-22	1,774	653,409		47,902		605,507-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	850,299	425,892	50	217,236	26	208,656-	25-
1978	886,638	586,726	66	634,976	72	48,250	5
1979	1,413,342	478,289	34	803,126	57	324,837	23
1980	562,045	834,189	148	1,041,514	185	207,325	37
1981	821,250	648,990	79	663,162	81	14,172	2
1982	778,781	697,327	90	367,614	47	329,713-	42-
1983	1,717,557	1,090,529	63	549,496	32	541,033-	32-
1984	796,778	872,835	110	485,535	61	387,300-	49-
1985	1,200,639	859,445	72	457,699	38	401,746-	33-
1986	1,559,492	1,145,026	73	571,390	37	573,636-	37-
1987	3,242,230	801,986	25	1,001,234	31	199,248	6
1988	2,118,682	771,063	36	737,252	35	33,811-	2-
1989	1,815,517	810,446	45	863,537	48	53,091	3
1990	2,716,656	144,305	5	79,643	3	64,662-	2-
1991	2,338,662	27,741	1	277,296	12	249,555	11
1992	2,136,602	15,761-	1-	389,440	18	405,201	19
1993	2,148,795	2,157,392	100	896,843	42	1,260,549-	59-
1994	1,676,086	933,596	56	804,019	48	129,577-	8-
1995	2,094,592	812,430	39	1,059,696	51	247,266	12
1996	2,178,230	1,006,403	46	736,202	34	270,202-	12-
1997	943,159	941,387	100	544,488	58	396,900-	42-
1998	407,310	1,816,262	446	975,312	239	840,949-	206-
1999	1,578	1,726,430			0	1,726,430-	
2000	609,268	1,713,821	281	108,062	18	1,605,759-	264-
2001	1,048,392	1,800,089	172		0	1,800,089-	172-
2002	7,153,614	2,736,351	38	216,818	3	2,519,534-	35-
2003	285,772	2,348,955	822	263,811	92	2,085,144-	730-
2004	269,906	2,577,691	955	475,702	176	2,101,989-	779-
2005	579,058	2,735,974	472	439,840	76	2,296,134-	397-
2006	143,881	3,351,410		794,288	552	2,557,122-	
2007	10,250	3,551,527		1,102,844		2,448,683-	
2008	124,044	3,377,240		842,758	679	2,534,482-	
2009	18,678,195	5,637,927	30		0	5,637,927-	30-
2010	8,510,553	6,736,770	79	2,199,638	26	4,537,132-	53-
2011	6,387,571	5,104,495	80	1,957,479	31	3,147,015-	49-
2012	8,682,075	4,847,036	56	5,290,840	61	443,804	5
2013	9,490,210	5,279,765	56	5,004,951	53	274,815-	3-
2014	8,944,376	3,813,837	43	4,148,604	46	334,767	4
2015	5,170,996	4,227,289	82	548,551	11	3,678,738-	71-
2016	7,719,209	3,450,226	45		0	3,450,226-	45-
2017	6,807,233	5,525,472	81		0	5,525,472-	81-
2018	7,923,711	3,692,718	47		0	3,692,718-	47-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	9,020,595	4,113,293	46	158,429	2	3,954,864-	44-
2020	5,361,620	3,209,537	60	105,017	2	3,104,521-	58-
2021	4,729,177	3,808,834	81	412,869	9	3,395,965-	72-
2022	5,093,624	5,553,014	109	401,490	8	5,151,524-	101-
TOTAL	157,148,249	108,766,199	69	38,628,699	25	70,137,501-	45-
THREE-YEAR MOVING AVERAGES							
77-79	1,050,093	496,969	47	551,779	53	54,810	5
78-80	954,008	633,068	66	826,539	87	193,471	20
79-81	932,212	653,823	70	835,934	90	182,111	20
80-82	720,692	726,835	101	690,763	96	36,072-	5-
81-83	1,105,863	812,282	73	526,757	48	285,525-	26-
82-84	1,097,705	886,897	81	467,548	43	419,349-	38-
83-85	1,238,325	940,936	76	497,577	40	443,360-	36-
84-86	1,185,636	959,102	81	504,875	43	454,227-	38-
85-87	2,000,787	935,486	47	676,774	34	258,711-	13-
86-88	2,306,801	906,025	39	769,959	33	136,066-	6-
87-89	2,392,143	794,498	33	867,341	36	72,843	3
88-90	2,216,952	575,271	26	560,144	25	15,127-	1-
89-91	2,290,278	327,497	14	406,825	18	79,328	3
90-92	2,397,306	52,095	2	248,793	10	196,698	8
91-93	2,208,020	723,124	33	521,193	24	201,931-	9-
92-94	1,987,161	1,025,076	52	696,767	35	328,308-	17-
93-95	1,973,158	1,301,140	66	920,186	47	380,954-	19-
94-96	1,982,969	917,477	46	866,639	44	50,838-	3-
95-97	1,738,660	920,074	53	780,128	45	139,945-	8-
96-98	1,176,233	1,254,684	107	752,001	64	502,683-	43-
97-99	450,682	1,494,693	332	506,600	112	988,093-	219-
98-00	339,385	1,752,171	516	361,125	106	1,391,046-	410-
99-01	553,079	1,746,780	316	36,021	7	1,710,759-	309-
00-02	2,937,091	2,083,420	71	108,293	4	1,975,127-	67-
01-03	2,829,259	2,295,132	81	160,210	6	2,134,922-	75-
02-04	2,569,764	2,554,332	99	318,777	12	2,235,556-	87-
03-05	378,245	2,554,207	675	393,118	104	2,161,089-	571-
04-06	330,948	2,888,358	873	569,943	172	2,318,415-	701-
05-07	244,397	3,212,970		778,991	319	2,433,980-	996-
06-08	92,725	3,426,725		913,296	985	2,513,429-	
07-09	6,270,830	4,188,898	67	648,534	10	3,540,364-	56-
08-10	9,104,264	5,250,646	58	1,014,132	11	4,236,514-	47-
09-11	11,192,106	5,826,397	52	1,385,706	12	4,440,692-	40-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	7,860,066	5,562,767	71	3,149,319	40	2,413,448-	31-
11-13	8,186,619	5,077,099	62	4,084,423	50	992,675-	12-
12-14	9,038,887	4,646,879	51	4,814,798	53	167,919	2
13-15	7,868,528	4,440,297	56	3,234,035	41	1,206,262-	15-
14-16	7,278,194	3,830,451	53	1,565,718	22	2,264,732-	31-
15-17	6,565,813	4,400,996	67	182,850	3	4,218,146-	64-
16-18	7,483,384	4,222,805	56		0	4,222,805-	56-
17-19	7,917,180	4,443,828	56	52,810	1	4,391,018-	55-
18-20	7,435,309	3,671,849	49	87,815	1	3,584,034-	48-
19-21	6,370,464	3,710,555	58	225,438	4	3,485,117-	55-
20-22	5,061,474	4,190,462	83	306,459	6	3,884,003-	77-
FIVE-YEAR AVERAGE							
18-22	6,425,745	4,075,479	63	215,561	3	3,859,918-	60-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	1,681,801	46,451	3	263,954	16	217,503	13
1978	1,626,141	154,258	9	386,736	24	232,478	14
1979	2,092,766	176,641	8	339,140	16	162,499	8
1980	2,035,004	153,089	8	330,811	16	177,722	9
1981	1,633,742	158,880	10	138,433	8	20,447-	1-
1982	1,974,405	246,935	13	189,446	10	57,489-	3-
1983	3,632,512	279,363	8	386,412	11	107,049	3
1984	3,181,094	337,690	11	186,999	6	150,691-	5-
1985	4,048,055	367,798	9	158,119	4	209,679-	5-
1986	4,826,175	457,088	9	359,719	7	97,369-	2-
1987	4,843,620	229,970	5	249,127	5	19,157	0
1988	3,373,098	217,855	6	166,288	5	51,567-	2-
1989	2,293,694	238,813	10	135,754	6	103,059-	4-
1990	3,171,947	45,638	1	638	0	45,000-	1-
1991	3,200,051	545	0	143,785	4	143,240	4
1992	3,683,573	66-	0	203,670	6	203,736	6
1993	3,477,165	2,704,932	78	239,459	7	2,465,473-	71-
1994	4,077,017	36,446-	1-	285,218	7	321,664	8
1995	4,630,082	4,654	0	184,528	4	179,874	4
1996	5,504,688	39,438	1	90,848	2	51,410	1
1997	2,992,626	21,042	1	62,018	2	40,976	1
1998	2,140,107	16,093	1	11,764	1	4,329-	0
1999	1,721,742	1,930,120	112		0	1,930,120-	112-
2000	3,170,468	2,265,073	71		0	2,265,073-	71-
2001	2,768,409	2,336,865	84		0	2,336,865-	84-
2002	5,294,483	4,580,328	87	154,755	3	4,425,573-	84-
2003	4,299,435	3,616,921	84	173,018	4	3,443,903-	80-
2004	3,967,271	4,386,235	111	249,258	6	4,136,977-	104-
2005	8,236,658	4,125,374	50	407,356	5	3,718,018-	45-
2006	6,225,328	5,101,133	82	673,869	11	4,427,264-	71-
2007	4,671,395	4,838,617	104	630,116	13	4,208,501-	90-
2008	4,725,887	6,011,752	127	760,281	16	5,251,472-	111-
2009	36,505,884	6,095,840	17		0	6,095,840-	17-
2010	10,982,975	7,496,106	68	1,445,775	13	6,050,331-	55-
2011	10,038,733	7,261,522	72	1,286,609	13	5,974,913-	60-
2012	8,308,584	15,471,977	186	70,172	1	15,401,805-	185-
2013	6,047,752	4,821,522	80		0	4,821,522-	80-
2014	5,898,584	7,904,566	134	880	0	7,903,686-	134-
2015	4,963,932	7,430,421	150	526,585	11	6,903,836-	139-
2016	7,237,046	10,354,742	143		0	10,354,742-	143-
2017	6,163,022	9,249,808	150		0	9,249,808-	150-
2018	6,024,996	13,629,151	226		0	13,629,151-	226-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	6,210,551	13,931,465	224	4,452	0	13,927,013-	224-
2020	5,735,397	15,994,886	279	9,214	0	15,985,672-	279-
2021	6,194,568	12,970,138	209		0	12,970,138-	209-
2022	7,634,311	12,430,563	163		0	12,430,563-	163-
TOTAL	243,146,774	190,095,789	78	10,905,209	4	179,190,580-	74-
THREE-YEAR MOVING AVERAGES							
77-79	1,800,236	125,783	7	329,943	18	204,160	11
78-80	1,917,970	161,329	8	352,229	18	190,900	10
79-81	1,920,504	162,870	8	269,461	14	106,591	6
80-82	1,881,050	186,301	10	219,563	12	33,262	2
81-83	2,413,553	228,393	9	238,097	10	9,704	0
82-84	2,929,337	287,996	10	254,286	9	33,710-	1-
83-85	3,620,554	328,284	9	243,843	7	84,440-	2-
84-86	4,018,441	387,525	10	234,946	6	152,580-	4-
85-87	4,572,617	351,619	8	255,655	6	95,964-	2-
86-88	4,347,631	301,638	7	258,378	6	43,260-	1-
87-89	3,503,471	228,879	7	183,723	5	45,156-	1-
88-90	2,946,246	167,435	6	100,893	3	66,542-	2-
89-91	2,888,564	94,999	3	93,393	3	1,606-	0
90-92	3,351,857	15,372	0	116,031	3	100,659	3
91-93	3,453,597	901,804	26	195,638	6	706,166-	20-
92-94	3,745,918	889,473	24	242,782	6	646,691-	17-
93-95	4,061,421	891,047	22	236,402	6	654,645-	16-
94-96	4,737,262	2,549	0	186,864	4	184,316	4
95-97	4,375,799	21,711	0	112,465	3	90,753	2
96-98	3,545,807	25,525	1	54,877	2	29,352	1
97-99	2,284,825	655,752	29	24,594	1	631,158-	28-
98-00	2,344,106	1,403,762	60	3,921	0	1,399,841-	60-
99-01	2,553,539	2,177,353	85		0	2,177,353-	85-
00-02	3,744,453	3,060,756	82	51,585	1	3,009,171-	80-
01-03	4,120,775	3,511,372	85	109,258	3	3,402,114-	83-
02-04	4,520,396	4,194,495	93	192,344	4	4,002,151-	89-
03-05	5,501,121	4,042,844	73	276,544	5	3,766,299-	68-
04-06	6,143,086	4,537,581	74	443,494	7	4,094,086-	67-
05-07	6,377,794	4,688,375	74	570,447	9	4,117,928-	65-
06-08	5,207,537	5,317,168	102	688,089	13	4,629,079-	89-
07-09	15,301,055	5,648,737	37	463,466	3	5,185,271-	34-
08-10	17,404,915	6,534,566	38	735,352	4	5,799,214-	33-
09-11	19,175,864	6,951,156	36	910,795	5	6,040,361-	31-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	9,776,764	10,076,535	103	934,185	10	9,142,350-	94-
11-13	8,131,690	9,185,007	113	452,261	6	8,732,747-	107-
12-14	6,751,640	9,399,355	139	23,684	0	9,375,671-	139-
13-15	5,636,756	6,718,836	119	175,822	3	6,543,014-	116-
14-16	6,033,187	8,563,243	142	175,822	3	8,387,421-	139-
15-17	6,121,333	9,011,657	147	175,528	3	8,836,129-	144-
16-18	6,475,021	11,077,900	171		0	11,077,900-	171-
17-19	6,132,856	12,270,141	200	1,484	0	12,268,657-	200-
18-20	5,990,315	14,518,500	242	4,555	0	14,513,945-	242-
19-21	6,046,839	14,298,830	236	4,555	0	14,294,274-	236-
20-22	6,521,425	13,798,529	212	3,071	0	13,795,458-	212-
FIVE-YEAR AVERAGE							
18-22	6,359,965	13,791,241	217	2,733	0	13,788,507-	217-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	219,304	780,580	356	113,555	52	667,025-	304-
1978	271,393	941,227	347	125,977	46	815,250-	300-
1979	238,759	890,770	373	107,850	45	782,920-	328-
1980	230,796	841,304	365	110,215	48	731,089-	317-
1981	192,694	878,695	456	116,079	60	762,616-	396-
1982	191,592	1,159,225	605	108,198	56	1,051,027-	549-
1983	159,192	1,374,929	864	104,733	66	1,270,196-	798-
1984	126,601	1,508,006		87,481	69	1,420,525-	
1985	412,240	1,829,534	444	93,048	23	1,736,486-	421-
1986	312,967	1,939,832	620	132,539	42	1,807,293-	577-
1987	355,128	1,362,135	384	154,932	44	1,207,203-	340-
1988	333,248	1,437,682	431	186,889	56	1,250,793-	375-
1989	322,458	1,286,691	399	137,033	42	1,149,658-	357-
1990	304,786	27,201	9	1,086	0	26,115-	9-
1991	275,085	529-	0	60,521	22	61,050	22
1992	254,692	179,884	71	48,556	19	131,328-	52-
1993	255,467	3,001,418		154,604	61	2,846,814-	
1994	200,220	3,752,675		122,426	61	3,630,249-	
1995	184,714	4,283,627		221,119	120	4,062,507-	
1996	89,930	3,685,038		73,289	81	3,611,748-	
1997	52,717	3,004,144		42,195	80	2,961,950-	
1998	31,574	2,795,979		56,914	180	2,739,065-	
1999	1,543	1,131,881			0	1,131,881-	
2000	44,024	1,888,172			0	1,888,172-	
2001	45,485	1,239,757			0	1,239,757-	
2002	482,573	1,811,189	375	18,368	4	1,792,820-	372-
2003	28,039	1,563,254		22,350	80	1,540,905-	
2004	44,969	1,944,199		40,301	90	1,903,898-	
2005	23,834	2,056,609		37,263	156	2,019,346-	
2006	12,217	2,128,558		67,291	551	2,061,267-	
2007	6,888	2,006,298		93,431		1,912,867-	
2008	2,229	1,752,809		71,397		1,681,412-	
2009	253,643	1,795,108	708		0	1,795,108-	708-
2010	1,392,128	2,120,349	152		0	2,120,349-	152-
2011	1,450,669	2,069,921	143		0	2,069,921-	143-
2012	724,754	3,146,232	434		0	3,146,232-	434-
2013	273,597	1,582,516	578		0	1,582,516-	578-
2014	331,271	1,722,307	520		0	1,722,307-	520-
2015	258,051	2,048,632	794	27,375	11	2,021,258-	783-
2016	435,759	2,056,834	472		0	2,056,834-	472-
2017	798,319	1,886,123	236		0	1,886,123-	236-
2018	294,722	2,786,064	945		0	2,786,064-	945-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	471,597	2,308,140	489	88,016	19	2,220,124-	471-
2020	316,295	2,585,307	817	58,343	18	2,526,964-	799-
2021	248,088	3,657,641		229,372	92	3,428,269-	
2022	303,775	3,190,778		223,050	73	2,967,728-	977-
TOTAL	13,260,023	87,438,725	659	3,335,795	25	84,102,930-	634-
THREE-YEAR MOVING AVERAGES							
77-79	243,152	870,859	358	115,794	48	755,065-	311-
78-80	246,983	891,100	361	114,681	46	776,420-	314-
79-81	220,750	870,256	394	111,381	50	758,875-	344-
80-82	205,027	959,741	468	111,497	54	848,244-	414-
81-83	181,159	1,137,616	628	109,670	61	1,027,946-	567-
82-84	159,128	1,347,387	847	100,137	63	1,247,249-	784-
83-85	232,678	1,570,823	675	95,087	41	1,475,736-	634-
84-86	283,936	1,759,124	620	104,356	37	1,654,768-	583-
85-87	360,112	1,710,500	475	126,840	35	1,583,661-	440-
86-88	333,781	1,579,883	473	158,120	47	1,421,763-	426-
87-89	336,945	1,362,169	404	159,618	47	1,202,551-	357-
88-90	320,164	917,191	286	108,336	34	808,855-	253-
89-91	300,776	437,788	146	66,213	22	371,574-	124-
90-92	278,188	68,852	25	36,721	13	32,131-	12-
91-93	261,748	1,060,258	405	87,894	34	972,364-	371-
92-94	236,793	2,311,326	976	108,529	46	2,202,797-	930-
93-95	213,467	3,679,240		166,050	78	3,513,190-	
94-96	158,288	3,907,113		138,945	88	3,768,168-	
95-97	109,120	3,657,603		112,201	103	3,545,402-	
96-98	58,073	3,161,720		57,466	99	3,104,254-	
97-99	28,611	2,310,668		33,036	115	2,277,632-	
98-00	25,714	1,938,677		18,971	74	1,919,706-	
99-01	30,351	1,419,937			0	1,419,937-	
00-02	190,694	1,646,373	863	6,123	3	1,640,250-	860-
01-03	185,365	1,538,067	830	13,573	7	1,524,494-	822-
02-04	185,194	1,772,881	957	27,006	15	1,745,874-	943-
03-05	32,280	1,854,687		33,304	103	1,821,383-	
04-06	27,007	2,043,122		48,285	179	1,994,837-	
05-07	14,313	2,063,822		65,995	461	1,997,827-	
06-08	7,111	1,962,555		77,373		1,885,182-	
07-09	87,586	1,851,405		54,943	63	1,796,462-	
08-10	549,333	1,889,422	344	23,799	4	1,865,623-	340-
09-11	1,032,146	1,995,126	193		0	1,995,126-	193-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	1,189,184	2,445,501	206		0	2,445,501-	206-
11-13	816,340	2,266,223	278		0	2,266,223-	278-
12-14	443,208	2,150,351	485		0	2,150,351-	485-
13-15	287,640	1,784,485	620	9,125	3	1,775,360-	617-
14-16	341,694	1,942,591	569	9,125	3	1,933,466-	566-
15-17	497,376	1,997,196	402	9,125	2	1,988,072-	400-
16-18	509,600	2,243,007	440		0	2,243,007-	440-
17-19	521,546	2,326,776	446	29,339	6	2,297,437-	441-
18-20	360,871	2,559,837	709	48,786	14	2,511,051-	696-
19-21	345,327	2,850,362	825	125,243	36	2,725,119-	789-
20-22	289,386	3,144,575		170,255	59	2,974,320-	
FIVE-YEAR AVERAGE							
18-22	326,896	2,905,586	889	119,756	37	2,785,830-	852-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	453,940		0	5,440	1	5,440	1
1978	472,269		0	11,586	2	11,586	2
1979	422,830		0	10,044	2	10,044	2
1980	393,166		0	13,616	3	13,616	3
1981	535,543		0	18,120	3	18,120	3
1982	463,738		0	8,622	2	8,622	2
1983	627,909		0	7,986	1	7,986	1
1984	570,989		0	4,291	1	4,291	1
1985	1,275,752		0	14,076	1	14,076	1
1986	968,649		0	4,994	1	4,994	1
1987	1,430,523		0	3,672	0	3,672	0
1988	944,436		0	32,541	3	32,541	3
1989	1,068,131		0	8,369	1	8,369	1
1990	2,473,471		0		0		0
1991	1,968,720	62,075	3	1,157	0	60,917-	3-
1992	2,126,892		0	2,553	0	2,553	0
1993	1,397,651		0	10,968-	1-	10,968-	1-
1994	1,279,407		0	5,310	0	5,310	0
1995	756,556		0	14,091	2	14,091	2
1996	40,283		0	610	2	610	2
1997	14,698		0		0		0
1998	3,978,891		0	1,013	0	1,013	0
1999	468,900	367	0		0	367-	0
2000	4,656,816	942,152	20		0	942,152-	20-
2001	1,724,185	706,999	41		0	706,999-	41-
2002	1,483,052	1,175,481	79		0	1,175,481-	79-
2003	1,522,533	2,013,790	132		0	2,013,790-	132-
2004	2,346,937	2,244,830	96		0	2,244,830-	96-
2005	1,606,594	1,984,475	124		0	1,984,475-	124-
2006	1,722,364	1,863,870	108		0	1,863,870-	108-
2007	2,046,372	2,029,130	99		0	2,029,130-	99-
2008	1,913,858	1,981,217	104		0	1,981,217-	104-
2009	1,684,233	1,311,804	78		0	1,311,804-	78-
2010	6,133,972	1,584,402	26		0	1,584,402-	26-
2011	3,813,298	2,542,849	67		0	2,542,849-	67-
2012	5,542,932	3,681,758	66		0	3,681,758-	66-
2013	4,592,069	3,577,830	78		0	3,577,830-	78-
2014	4,380,925	4,092,534	93		0	4,092,534-	93-
2015	6,013,394	5,007,788	83	637,914	11	4,369,873-	73-
2016	5,053,330	3,762,513	74		0	3,762,513-	74-
2017	6,517,766	3,425,446	53		0	3,425,446-	53-
2018	5,500,745	3,787,282	69		0	3,787,282-	69-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	3,269,531	3,892,480	119	158,429	5	3,734,052-	114-
2020	2,631,010	3,640,789	138	105,017	4	3,535,773-	134-
2021	5,048,327	5,392,467	107	412,869	8	4,979,598-	99-
2022	24,133,447	9,959,151	41	333,817	1	9,625,335-	40-
TOTAL	127,471,034	70,663,478	55	1,805,169	1	68,858,309-	54-
THREE-YEAR MOVING AVERAGES							
77-79	449,680		0	9,023	2	9,023	2
78-80	429,422		0	11,749	3	11,749	3
79-81	450,513		0	13,927	3	13,927	3
80-82	464,149		0	13,453	3	13,453	3
81-83	542,397		0	11,576	2	11,576	2
82-84	554,212		0	6,966	1	6,966	1
83-85	824,883		0	8,784	1	8,784	1
84-86	938,463		0	7,787	1	7,787	1
85-87	1,224,975		0	7,581	1	7,581	1
86-88	1,114,536		0	13,736	1	13,736	1
87-89	1,147,697		0	14,861	1	14,861	1
88-90	1,495,346		0	13,637	1	13,637	1
89-91	1,836,774	20,692	1	3,175	0	17,516-	1-
90-92	2,189,694	20,692	1	1,237	0	19,455-	1-
91-93	1,831,088	20,692	1	2,419-	0	23,111-	1-
92-94	1,601,317		0	1,035-	0	1,035-	0
93-95	1,144,538		0	2,811	0	2,811	0
94-96	692,082		0	6,670	1	6,670	1
95-97	270,512		0	4,900	2	4,900	2
96-98	1,344,624		0	541	0	541	0
97-99	1,487,496	122	0	338	0	215	0
98-00	3,034,869	314,173	10	338	0	313,835-	10-
99-01	2,283,300	549,839	24		0	549,839-	24-
00-02	2,621,351	941,544	36		0	941,544-	36-
01-03	1,576,590	1,298,757	82		0	1,298,757-	82-
02-04	1,784,174	1,811,367	102		0	1,811,367-	102-
03-05	1,825,355	2,081,032	114		0	2,081,032-	114-
04-06	1,891,965	2,031,058	107		0	2,031,058-	107-
05-07	1,791,776	1,959,158	109		0	1,959,158-	109-
06-08	1,894,198	1,958,072	103		0	1,958,072-	103-
07-09	1,881,488	1,774,050	94		0	1,774,050-	94-
08-10	3,244,021	1,625,807	50		0	1,625,807-	50-
09-11	3,877,167	1,813,018	47		0	1,813,018-	47-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	5,163,400	2,603,003	50		0	2,603,003-	50-
11-13	4,649,433	3,267,479	70		0	3,267,479-	70-
12-14	4,838,642	3,784,041	78		0	3,784,041-	78-
13-15	4,995,463	4,226,051	85	212,638	4	4,013,412-	80-
14-16	5,149,216	4,287,612	83	212,638	4	4,074,974-	79-
15-17	5,861,497	4,065,249	69	212,638	4	3,852,611-	66-
16-18	5,690,614	3,658,414	64		0	3,658,414-	64-
17-19	5,096,014	3,701,736	73	52,810	1	3,648,926-	72-
18-20	3,800,429	3,773,517	99	87,815	2	3,685,702-	97-
19-21	3,649,623	4,308,579	118	225,438	6	4,083,141-	112-
20-22	10,604,261	6,330,802	60	283,901	3	6,046,902-	57-
FIVE-YEAR AVERAGE							
18-22	8,116,612	5,334,434	66	202,026	2	5,132,408-	63-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	1,613,578	461,064	29	532,684	33	71,620	4
1978	1,389,676	537,145	39	578,938	42	41,793	3
1979	1,947,455	744,789	38	695,193	36	49,596-	3-
1980	1,347,112	276,344	21	516,653	38	240,309	18
1981	1,511,131	774,224	51	630,358	42	143,866-	10-
1982	1,435,440	883,803	62	550,154	38	333,649-	23-
1983	2,550,992	1,371,019	54	710,740	28	660,279-	26-
1984	1,531,631	1,035,347	68	704,250	46	331,097-	22-
1985	1,787,650	1,183,301	66	623,390	35	559,911-	31-
1986	1,771,682	1,315,632	74	981,677	55	333,955-	19-
1987	1,693,916	853,890	50	652,972	39	200,918-	12-
1988	1,571,937	862,452	55	560,427	36	302,025-	19-
1989	1,266,162	996,749	79	559,159	44	437,590-	35-
1990	1,417,201	1,471	0	1,655	0	184	0
1991	1,196,174	5,119-	0	297,536	25	302,656	25
1992	1,422,225	180,242	13	83,869-	6-	264,111-	19-
1993	1,326,606	618,938	47	577,833	44	41,105-	3-
1994	1,251,268	681,909	54	585,743	47	96,165-	8-
1995	1,431,876	632,695	44	706,500	49	73,806	5
1996	1,651,997	1,444,082	87	603,928	37	840,153-	51-
1997	1,142,754	1,451,171	127	758,302	66	692,869-	61-
1998	1,038,453	774,992	75	586,547	56	188,445-	18-
1999	47,123	1,237,747			0	1,237,747-	
2000	698,121	1,070,171	153		0	1,070,171-	153-
2001	730,660	609,375	83		0	609,375-	83-
2002	670,412	707,313	106	112,291	17	595,022-	89-
2003	530,301	215,588	41	136,682	26	78,906-	15-
2004	568,695	721,456	127	247,668	44	473,788-	83-
2005	537,868	881,789	164	240,298	45	641,491-	119-
2006	552,909	1,087,456	197	411,365	74	676,090-	122-
2007	667,633	1,252,182	188	571,168	86	681,014-	102-
2008	799,659	1,140,808	143	436,468	55	704,340-	88-
2009	276,171-	2,823,999			0	2,823,999-	
2010	10,238,950	4,842,100	47		0	4,842,100-	47-
2011	1,334,241	3,121,468	234	750	0	3,120,718-	234-
2012	2,508,234	2,973,229	119		0	2,973,229-	119-
2013	4,851,209	2,666,988	55		0	2,666,988-	55-
2014	3,275,089	2,281,091	70		0	2,281,091-	70-
2015	4,564,666	2,693,048	59	484,230	11	2,208,818-	48-
2016	4,866,898	2,842,185	58		0	2,842,185-	58-
2017	3,694,919	2,509,205	68		0	2,509,205-	68-
2018	6,600,367	3,014,074	46		0	3,014,074-	46-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	5,852,515	2,558,906	44	105,619	2	2,453,287-	42-
2020	6,518,749	2,762,877	42	70,011	1	2,692,866-	41-
2021	7,425,128	3,044,657	41	275,246	4	2,769,411-	37-
2022	11,581,530	4,079,026	35	267,660	2	3,811,366-	33-
TOTAL	112,136,621	68,212,879	61	15,690,229	14	52,522,650-	47-
THREE-YEAR MOVING AVERAGES							
77-79	1,650,236	580,999	35	602,272	36	21,272	1
78-80	1,561,414	519,426	33	596,928	38	77,502	5
79-81	1,601,899	598,452	37	614,068	38	15,616	1
80-82	1,431,228	644,790	45	565,722	40	79,069-	6-
81-83	1,832,521	1,009,682	55	630,417	34	379,265-	21-
82-84	1,839,354	1,096,723	60	655,048	36	441,675-	24-
83-85	1,956,758	1,196,556	61	679,460	35	517,096-	26-
84-86	1,696,988	1,178,093	69	769,772	45	408,321-	24-
85-87	1,751,083	1,117,608	64	752,680	43	364,928-	21-
86-88	1,679,178	1,010,658	60	731,692	44	278,966-	17-
87-89	1,510,672	904,364	60	590,853	39	313,511-	21-
88-90	1,418,433	620,224	44	373,747	26	246,477-	17-
89-91	1,293,179	331,034	26	286,117	22	44,917-	3-
90-92	1,345,200	58,865	4	71,774	5	12,909	1
91-93	1,315,002	264,687	20	263,833	20	854-	0
92-94	1,333,366	493,696	37	359,902	27	133,794-	10-
93-95	1,336,584	644,514	48	623,359	47	21,155-	2-
94-96	1,445,047	919,562	64	632,057	44	287,504-	20-
95-97	1,408,876	1,175,982	83	689,577	49	486,406-	35-
96-98	1,277,735	1,223,415	96	649,593	51	573,822-	45-
97-99	742,777	1,154,637	155	448,283	60	706,354-	95-
98-00	594,566	1,027,637	173	195,516	33	832,121-	140-
99-01	491,968	972,431	198		0	972,431-	198-
00-02	699,731	795,620	114	37,430	5	758,190-	108-
01-03	643,791	510,759	79	82,991	13	427,768-	66-
02-04	589,802	548,119	93	165,547	28	382,572-	65-
03-05	545,621	606,278	111	208,216	38	398,062-	73-
04-06	553,157	896,900	162	299,777	54	597,123-	108-
05-07	586,137	1,073,809	183	407,610	70	666,198-	114-
06-08	673,401	1,160,149	172	473,001	70	687,148-	102-
07-09	397,040	1,738,997	438	335,879	85	1,403,118-	353-
08-10	3,587,479	2,935,636	82	145,489	4	2,790,146-	78-
09-11	3,765,673	3,595,855	95	250	0	3,595,605-	95-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	4,693,808	3,645,599	78	250	0	3,645,349-	78-
11-13	2,897,895	2,920,562	101	250	0	2,920,312-	101-
12-14	3,544,844	2,640,436	74		0	2,640,436-	74-
13-15	4,230,321	2,547,042	60	161,410	4	2,385,632-	56-
14-16	4,235,551	2,605,441	62	161,410	4	2,444,031-	58-
15-17	4,375,494	2,681,479	61	161,410	4	2,520,069-	58-
16-18	5,054,061	2,788,488	55		0	2,788,488-	55-
17-19	5,382,600	2,694,062	50	35,206	1	2,658,855-	49-
18-20	6,323,877	2,778,619	44	58,543	1	2,720,076-	43-
19-21	6,598,798	2,788,814	42	150,292	2	2,638,521-	40-
20-22	8,508,469	3,295,520	39	204,306	2	3,091,215-	36-
FIVE-YEAR AVERAGE							
18-22	7,595,658	3,091,908	41	143,707	2	2,948,201-	39-

GAS PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	21,934	3,698	17	139	1	3,559-	16-
1976	1,859	2,658	143		0	2,658-	143-
1977	1,037,027	106,243	10	355	0	105,888-	10-
1978	2,323,534	812,683	35	12,015	1	800,668-	34-
1979	3,067-	3,135	102-		0	3,135-	102
1980	166,573	3,430	2	12,732	8	9,302	6
1981	13,221	1	0		0	1-	0
1982	1,682	547	33		0	547-	33-
1983	4,793-	511-	11		0	511	11-
1984							
1985	3,003,953	529,866	18	26	0	529,840-	18-
1986	120-	22-	18		0	22	18-
1987	1,598,210	165,100	10		0	165,100-	10-
1988	20,000-	86,477	432-		0	86,477-	432
1989	1,894,682	75,241	4		0	75,241-	4-
1990	579		0		0		0
1991							
1992							
1993	31,403		0		0		0
1994							
1995	48		0		0		0
1996	20,761-		0		0		0
1997							
1998	70,657		0		0		0
1999							
2000	15,589,755		0		0		0
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016		8,544				8,544-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017		7,483				7,483-	
2018		54,749				54,749-	
2019							
2020							
2021		82,719				82,719-	
2022							
TOTAL	25,706,376	1,942,041	8	25,267	0	1,916,774-	7-
THREE-YEAR MOVING AVERAGES							
75-77	353,607	37,533	11	165	0	37,368-	11-
76-78	1,120,807	307,195	27	4,123	0	303,071-	27-
77-79	1,119,165	307,354	27	4,123	0	303,230-	27-
78-80	829,013	273,083	33	8,249	1	264,834-	32-
79-81	58,909	2,189	4	4,244	7	2,055	3
80-82	60,492	1,326	2	4,244	7	2,918	5
81-83	3,370	12	0		0	12-	0
82-84	1,037-	12	1-		0	12-	1
83-85	999,720	176,452	18	9	0	176,443-	18-
84-86	1,001,278	176,615	18	9	0	176,606-	18-
85-87	1,534,014	231,648	15	9	0	231,639-	15-
86-88	526,030	83,852	16		0	83,852-	16-
87-89	1,157,631	108,939	9		0	108,939-	9-
88-90	625,087	53,906	9		0	53,906-	9-
89-91	631,754	25,080	4		0	25,080-	4-
90-92	193		0		0		0
91-93	10,468		0		0		0
92-94	10,468		0		0		0
93-95	10,484		0		0		0
94-96	6,904-		0		0		0
95-97	6,904-		0		0		0
96-98	16,632		0		0		0
97-99	23,552		0		0		0
98-00	5,220,137		0		0		0
99-01	5,196,585		0		0		0
00-02	5,196,585		0		0		0
01-03							
02-04							
03-05							
04-06							
05-07							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08							
07-09							
08-10							
09-11							
10-12							
11-13							
12-14							
13-15							
14-16		2,848				2,848-	
15-17		5,342				5,342-	
16-18		23,592				23,592-	
17-19		20,744				20,744-	
18-20		18,250				18,250-	
19-21		27,573				27,573-	
20-22		27,573				27,573-	
FIVE-YEAR AVERAGE							
18-22		27,494				27,494-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1975	1,117	84	8	1	0	83-	7-
1976							
1977	729,167	30,608	4		0	30,608-	4-
1978	929,007	265,283	29		0	265,283-	29-
1979		9,093				9,093-	
1980	1,133	2,656	234		0	2,656-	234-
1981	4,345	813-	19-		0	813	19
1982		2,385				2,385-	
1983							
1984							
1985	2,083,684	236,940	11		0	236,940-	11-
1986	170,478	7,208	4		0	7,208-	4-
1987	575,878	80,654	14		0	80,654-	14-
1988	1	75,303			0	75,303-	
1989							
1990							
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998	867-		0		0		0
1999							
2000							
2001	9,609,543		0		0		0
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL	14,103,486	709,401	5	1	0	709,400-	5-
THREE-YEAR MOVING AVERAGES							
75-77	243,428	10,231	4		0	10,230-	4-
76-78	552,725	98,630	18		0	98,630-	18-
77-79	552,725	101,661	18		0	101,661-	18-
78-80	310,047	92,344	30		0	92,344-	30-
79-81	1,826	3,645	200		0	3,645-	200-
80-82	1,826	1,409	77		0	1,409-	77-
81-83	1,448	524	36		0	524-	36-
82-84		795				795-	
83-85	694,561	78,980	11		0	78,980-	11-
84-86	751,387	81,383	11		0	81,383-	11-
85-87	943,347	108,267	11		0	108,267-	11-
86-88	248,786	54,388	22		0	54,388-	22-
87-89	191,960	51,986	27		0	51,986-	27-
88-90		25,101			0	25,101-	
89-91							
90-92							
91-93							
92-94							
93-95							
94-96							
95-97							
96-98	289-		0		0		0
97-99	289-		0		0		0
98-00	289-		0		0		0
99-01	3,203,181		0		0		0
00-02	3,203,181		0		0		0
01-03	3,203,181		0		0		0
02-04							
03-05							
04-06							
05-07							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
06-08							
07-09							
08-10							
09-11							
10-12							
11-13							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	35,854	1,839	5		0	1,839-	5-
1978	471,380	178,591	38		0	178,591-	38-
1979	8,300-	3,161-	38		0	3,161	38-
1980	259	99	38	1	0	98-	38-
1981							
1982							
1983							
1984							
1985	518,207	106,648	21	4	0	106,644-	21-
1986							
1987	7,452	16,797	225		0	16,797-	225-
1988		744				744-	
1989	158,476	6,300	4		0	6,300-	4-
1990	5,786		0		0		0
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998	57,694		0		0		0
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010				8,030		8,030	
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018	408,981		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2019	465,419		0		0		0
2020							
2021							
2022							
TOTAL	2,121,208	307,857	15	8,035	0	299,822-	14-
THREE-YEAR MOVING AVERAGES							
77-79	166,311	59,090	36		0	59,090-	36-
78-80	154,446	58,510	38		0	58,509-	38-
79-81	2,680-	1,021-	38		0	1,021	38-
80-82	86	33	38		0	33-	38-
81-83							
82-84							
83-85	172,736	35,549	21	1	0	35,548-	21-
84-86	172,736	35,549	21	1	0	35,548-	21-
85-87	175,220	41,148	23	1	0	41,147-	23-
86-88	2,484	5,847	235		0	5,847-	235-
87-89	55,309	7,947	14		0	7,947-	14-
88-90	54,754	2,348	4		0	2,348-	4-
89-91	54,754	2,100	4		0	2,100-	4-
90-92	1,929		0		0		0
91-93							
92-94							
93-95							
94-96							
95-97							
96-98	19,231		0		0		0
97-99	19,231		0		0		0
98-00	19,231		0		0		0
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10				2,677		2,677	
09-11				2,677		2,677	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12				2,677		2,677	
11-13							
12-14							
13-15							
14-16							
15-17							
16-18	136,327		0		0		0
17-19	291,467		0		0		0
18-20	291,467		0		0		0
19-21	155,140		0		0		0
20-22							
FIVE-YEAR AVERAGE							
18-22	174,880		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	29,485	1,039	4	14	0	1,025-	3-
1976	46,204	1,181	3	792	2	389-	1-
1977	3,274,252	252,319	8	217	0	252,102-	8-
1978	3,899,616	1,094,884	28	3,670	0	1,091,214-	28-
1979	13,571-	34,286-	253	70	1-	34,356	253-
1980	20,523	2,622	13	73	0	2,549-	12-
1981	13,078	3,036	23	117	1	2,919-	22-
1982	15,382	204	1	4	0	200-	1-
1983	36,173-	26,637-	74	4,692	13-	31,329	87-
1984	85,237	2,391	3	2	0	2,389-	3-
1985	2,646,939	269,645	10	3,655	0	265,990-	10-
1986	1,545,884	62,444	4	22,150	1	40,294-	3-
1987	6,948,691	443,290	6		0	443,290-	6-
1988	61,572	756,488			0	756,488-	
1989	2,549,546	1,138,994	45		0	1,138,994-	45-
1990	11,525		0		0		0
1991	977		0		0		0
1992	27,140-		0		0		0
1993	79		0		0		0
1994							
1995							
1996							
1997							
1998	42,048		0		0		0
1999							
2000							
2001	9,405,507		0		0		0
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012	459,695		0		0		0
2013							
2014							
2015							
2016							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017							
2018	129,738		0		0		0
2019							
2020							
2021							
2022							
TOTAL	31,109,094	3,967,614	13	35,456	0	3,932,158-	13-
THREE-YEAR MOVING AVERAGES							
75-77	1,116,647	84,846	8	341	0	84,505-	8-
76-78	2,406,691	449,461	19	1,560	0	447,902-	19-
77-79	2,386,766	437,639	18	1,319	0	436,320-	18-
78-80	1,302,189	354,407	27	1,271	0	353,136-	27-
79-81	6,677	9,543-	143-	87	1	9,629	144
80-82	16,328	1,954	12	65	0	1,889-	12-
81-83	2,571-	7,799-	303	1,604	62-	9,403	366-
82-84	21,482	8,014-	37-	1,566	7	9,580	45
83-85	898,668	81,800	9	2,783	0	79,017-	9-
84-86	1,426,020	111,493	8	8,602	1	102,891-	7-
85-87	3,713,838	258,460	7	8,602	0	249,858-	7-
86-88	2,852,049	420,741	15	7,383	0	413,357-	14-
87-89	3,186,603	779,591	24		0	779,591-	24-
88-90	874,214	631,827	72		0	631,827-	72-
89-91	854,016	379,665	44		0	379,665-	44-
90-92	4,879-		0		0		0
91-93	8,695-		0		0		0
92-94	9,020-		0		0		0
93-95	26		0		0		0
94-96							
95-97							
96-98	14,016		0		0		0
97-99	14,016		0		0		0
98-00	14,016		0		0		0
99-01	3,135,169		0		0		0
00-02	3,135,169		0		0		0
01-03	3,135,169		0		0		0
02-04							
03-05							
04-06							
05-07							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08							
07-09							
08-10							
09-11							
10-12	153,232		0		0		0
11-13	153,232		0		0		0
12-14	153,232		0		0		0
13-15							
14-16							
15-17							
16-18	43,246		0		0		0
17-19	43,246		0		0		0
18-20	43,246		0		0		0
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22	25,948		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1978	538,578		0		0		0
1979	847-		0		0		0
1980							
1981							
1982							
1983							
1984							
1985	678,211		0		0		0
1986	98,870		0		0		0
1987							
1988	400		0		0		0
1989							
1990							
1991	1,288,507		0		0		0
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999	1,205,179		0		0		0
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2020							
2021							
2022							
TOTAL	3,808,898		0		0		0
THREE-YEAR MOVING AVERAGES							
78-80	179,244		0		0		0
79-81	282-		0		0		0
80-82							
81-83							
82-84							
83-85	226,070		0		0		0
84-86	259,027		0		0		0
85-87	259,027		0		0		0
86-88	33,090		0		0		0
87-89	133		0		0		0
88-90	133		0		0		0
89-91	429,502		0		0		0
90-92	429,502		0		0		0
91-93	429,502		0		0		0
92-94							
93-95							
94-96							
95-97							
96-98							
97-99	401,726		0		0		0
98-00	401,726		0		0		0
99-01	401,726		0		0		0
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11							
10-12							
11-13							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 363.20 AND 363.40 OTHER STORAGE PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994	101,143		0		0		0
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012	163,526		0		0		0
2013							
2014		9,080				9,080-	
2015		618,973				618,973-	
2016		75,302				75,302-	
2017				3,280		3,280	
2018				18,448		18,448	
2019		909,897		6,364-		916,261-	
2020				3,380-		3,380-	
2021				1,270		1,270	
2022							
TOTAL	264,670	1,613,252	610	13,254	5	1,599,998-	605-
THREE-YEAR MOVING AVERAGES							
94-96	33,714		0		0		0
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 363.20 AND 363.40 OTHER STORAGE PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11							
10-12	54,509		0		0		0
11-13	54,509		0		0		0
12-14	54,509	3,027	6		0	3,027-	6-
13-15		209,351				209,351-	
14-16		234,452				234,452-	
15-17		231,425		1,093		230,332-	
16-18		25,101		7,243		17,858-	
17-19		303,299		5,121		298,178-	
18-20		303,299		2,901		300,398-	
19-21		303,299		2,825-		306,124-	
20-22				703-		703-	
FIVE-YEAR AVERAGE							
18-22		181,979		1,995		179,985-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1976		45		80		35	
1977		26				26-	
1978	101,126	33,305	33	763	1	32,542-	32-
1979		313				313-	
1980	283,791	6,602	2		0	6,602-	2-
1981							
1982		4,572				4,572-	
1983	5,810	3,571	61	4	0	3,567-	61-
1984	524,493	115,324	22	376	0	114,948-	22-
1985							
1986							
1987							
1988							
1989	102,473		0		0		0
1990							
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010	3,884,945		0		0		0
2011							
2012							
2013							
2014							
2015							
2016							
2017							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2018							
2019							
2020							
2021		138,542				138,542-	
2022		10,047-				10,047	
TOTAL	4,902,638	292,253	6	1,223	0	291,030-	6-
THREE-YEAR MOVING AVERAGES							
76-78	33,709	11,125	33	281	1	10,844-	32-
77-79	33,709	11,215	33	254	1	10,960-	33-
78-80	128,306	13,407	10	254	0	13,152-	10-
79-81	94,597	2,305	2		0	2,305-	2-
80-82	94,597	3,725	4		0	3,725-	4-
81-83	1,937	2,714	140	1	0	2,713-	140-
82-84	176,768	41,156	23	127	0	41,029-	23-
83-85	176,768	39,632	22	127	0	39,505-	22-
84-86	174,831	38,441	22	125	0	38,316-	22-
85-87							
86-88							
87-89	34,158		0		0		0
88-90	34,158		0		0		0
89-91	34,158		0		0		0
90-92							
91-93							
92-94							
93-95							
94-96							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
08-10	1,294,982		0		0		0
09-11	1,294,982		0		0		0
10-12	1,294,982		0		0		0
11-13							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
19-21		46,181				46,181-	
20-22		42,832				42,832-	
FIVE-YEAR AVERAGE							
18-22		25,699				25,699-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1999		367,216				367,216-	
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008		20,346				20,346-	
2009							
2010							
2011							
2012	2,075,076	487,623	23		0	487,623-	23-
2013		127-				127	
2014		93,801				93,801-	
2015		280,684				280,684-	
2016		320,079				320,079-	
2017		179,571		3,226		176,345-	
2018		231,809		6,855		224,954-	
2019		1,576,502		14,244		1,562,258-	
2020		710,521		1,419		709,102-	
2021		5,573		18,494		12,921	
2022		353,533		23,500		330,033-	
TOTAL	2,075,076	4,627,131	223	67,738	3	4,559,393-	220-
THREE-YEAR MOVING AVERAGES							
99-01		122,405				122,405-	
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08		6,782				6,782-	
07-09		6,782				6,782-	
08-10		6,782				6,782-	
09-11							
10-12	691,692	162,541	23		0	162,541-	23-
11-13	691,692	162,499	23		0	162,499-	23-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	691,692	193,766	28		0	193,766-	28-
13-15		124,786				124,786-	
14-16		231,521				231,521-	
15-17		260,111		1,075		259,036-	
16-18		243,820		3,360		240,459-	
17-19		662,627		8,108		654,519-	
18-20		839,611		7,506		832,105-	
19-21		764,199		11,386		752,813-	
20-22		356,542		14,471		342,071-	
FIVE-YEAR AVERAGE							
18-22		575,588		12,902		562,685-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	17,815	1,373	8	66	0	1,307-	7-
1976	39,925	1,941	5	125	0	1,816-	5-
1977	83,014	13,792	17	1	0	13,791-	17-
1978	13,215	1,079	8	48	0	1,031-	8-
1979	8,319	15,507	186		0	15,507-	186-
1980	78,465	15,045	19		0	15,045-	19-
1981	2,424	9,977	412		0	9,977-	412-
1982	198,252	4,040	2		0	4,040-	2-
1983	36,891	3,276	9		0	3,276-	9-
1984	238,377	5,605	2	200	0	5,405-	2-
1985	234,096		0	1,010	0	1,010	0
1986	17,037		0		0		0
1987	10,237		0	283	3	283	3
1988							
1989	103,350		0		0		0
1990		81,350				81,350-	
1991	11,625	151,693			0	151,693-	
1992		1,304,492				1,304,492-	
1993	106,199	66,874	63		0	66,874-	63-
1994	174,647	101,204	58		0	101,204-	58-
1995	321,357	23,177	7		0	23,177-	7-
1996	77,410	548,428	708		0	548,428-	708-
1997	53,861	9,179	17		0	9,179-	17-
1998	624,589		0		0		0
1999							
2000							
2001	76,772		0		0		0
2002							
2003							
2004							
2005	68,379		0		0		0
2006							
2007	34,747		0		0		0
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017		26,032				26,032-	
2018	179,797	131,315	73		0	131,315-	73-
2019	97,973	17,810	18		0	17,810-	18-
2020		4,101				4,101-	
2021	4,416	525,832			0	525,832-	
2022		135,844		991		134,853-	
TOTAL	2,913,189	3,198,966	110	2,724	0	3,196,242-	110-
THREE-YEAR MOVING AVERAGES							
75-77	46,918	5,702	12	64	0	5,638-	12-
76-78	45,385	5,604	12	58	0	5,546-	12-
77-79	34,849	10,126	29	16	0	10,110-	29-
78-80	33,333	10,544	32	16	0	10,528-	32-
79-81	29,736	13,510	45		0	13,510-	45-
80-82	93,047	9,687	10		0	9,687-	10-
81-83	79,189	5,764	7		0	5,764-	7-
82-84	157,840	4,307	3	67	0	4,240-	3-
83-85	169,788	2,960	2	403	0	2,557-	2-
84-86	163,170	1,868	1	403	0	1,465-	1-
85-87	87,123		0	431	0	431	0
86-88	9,091		0	94	1	94	1
87-89	37,862		0	94	0	94	0
88-90	34,450	27,117	79		0	27,117-	79-
89-91	38,325	77,681	203		0	77,681-	203-
90-92	3,875	512,512			0	512,512-	
91-93	39,275	507,686			0	507,686-	
92-94	93,615	490,857	524		0	490,857-	524-
93-95	200,734	63,752	32		0	63,752-	32-
94-96	191,138	224,270	117		0	224,270-	117-
95-97	150,876	193,595	128		0	193,595-	128-
96-98	251,953	185,869	74		0	185,869-	74-
97-99	226,150	3,060	1		0	3,060-	1-
98-00	208,196		0		0		0
99-01	25,591		0		0		0
00-02	25,591		0		0		0
01-03	25,591		0		0		0
02-04							
03-05	22,793		0		0		0
04-06	22,793		0		0		0
05-07	34,375		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	11,582	0		0		0	
07-09	11,582	0		0		0	
08-10							
09-11							
10-12							
11-13							
12-14							
13-15							
14-16							
15-17		8,677				8,677-	
16-18	59,932	52,449	88		0	52,449-	88-
17-19	92,590	58,386	63		0	58,386-	63-
18-20	92,590	51,075	55		0	51,075-	55-
19-21	34,130	182,581	535		0	182,581-	535-
20-22	1,472	221,926		330	22	221,595-	
FIVE-YEAR AVERAGE							
18-22	56,437	162,980	289	198	0	162,782-	288-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	744,088	359,031	48	10,979	1	348,052-	47-
1976	744,370	472,490	63	10,650	1	461,840-	62-
1977	808,232	783,894	97	11,300	1	772,594-	96-
1978	978,287	848,488	87	9,440	1	839,048-	86-
1979	1,000,160	737,855	74	11,056	1	726,799-	73-
1980	10,680,661	2,665,380	25	13,040	0	2,652,340-	25-
1981	973,068	829,946	85	6,174	1	823,772-	85-
1982	1,206,515	974,575	81	361	0	974,214-	81-
1983	1,269,775	1,189,830	94	1,045	0	1,188,785-	94-
1984	1,029,516	920,578	89	715	0	919,863-	89-
1985	1,388,460		0	5,078	0	5,078	0
1986	1,425,168		0	3,632	0	3,632	0
1987	1,288,488		0	5,504	0	5,504	0
1988	1,966,491	28,914	1	10,616	1	18,298-	1-
1989	1,562,485	50,803	3	6,107	0	44,696-	3-
1990	1,756,670	2,004,129	114	14,388	1	1,989,741-	113-
1991	2,235,895	2,514,326	112	14,596	1	2,499,730-	112-
1992	2,005,298	2,823,744	141	12,664	1	2,811,080-	140-
1993	1,661,369	2,993,277	180	5,631	0	2,987,646-	180-
1994	2,124,697	3,127,096	147	3,081	0	3,124,015-	147-
1995	892,361	3,074,817	345	3,460	0	3,071,357-	344-
1996	1,689,059	3,251,133	192	5,841	0	3,245,292-	192-
1997	2,190,239	2,378,015	109		0	2,378,015-	109-
1998	2,596,613	2,896,756	112		0	2,896,756-	112-
1999	1,080,010	1,927,738	178		0	1,927,738-	178-
2000	789,946	2,363,700	299		0	2,363,700-	299-
2001	2,244,272	1,993,357	89		0	1,993,357-	89-
2002	2,313,528	2,429,181	105	153,533	7	2,275,648-	98-
2003	1,855,648	2,532,374	136	78,376	4	2,453,998-	132-
2004	1,766,346	1,987,750	113	29,979	2	1,957,771-	111-
2005	3,620,002	2,532,151	70	72,293	2	2,459,858-	68-
2006	2,441,732	2,246,044	92	7,555	0	2,238,489-	92-
2007	3,756,756	3,766,675	100	9,965	0	3,756,710-	100-
2008	2,316,867	5,451,117	235	11,248	0	5,439,869-	235-
2009	1,856,994	5,697,885	307	71,257	4	5,626,628-	303-
2010	9,849,286	6,721,178	68	483	0	6,720,695-	68-
2011	2,813,944	6,043,381	215	15,610	1	6,027,771-	214-
2012	3,104,985	10,231,472	330	48,486	2	10,182,986-	328-
2013	631,566	2,980,570	472	14,028	2	2,966,542-	470-
2014	19,908,469	3,463,995	17	29,621	0	3,434,374-	17-
2015	10,944,270	10,439,443	95	12,778	0	10,426,665-	95-
2016	17,698,438	12,971,940	73	84,488	0	12,887,452-	73-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017	16,508,796	9,457,836	57	173,742	1	9,284,094-	56-
2018	23,616,904	15,025,784	64	195,572	1	14,830,212-	63-
2019	41,615,663	23,799,061	57	271,473	1	23,527,588-	57-
2020	24,910,661	5,632,222	23	55,388	0	5,576,834-	22-
2021	38,222,349	17,376,940	45	45,935	0	17,331,005-	45-
2022	32,838,657	3,743,510	11	122,325	0	3,621,185-	11-
TOTAL	310,924,054	195,740,381	63	1,669,494	1	194,070,887-	62-
THREE-YEAR MOVING AVERAGES							
75-77	765,563	538,472	70	10,976	1	527,495-	69-
76-78	843,630	701,624	83	10,463	1	691,161-	82-
77-79	928,893	790,079	85	10,599	1	779,480-	84-
78-80	4,219,703	1,417,241	34	11,179	0	1,406,062-	33-
79-81	4,217,963	1,411,060	33	10,090	0	1,400,970-	33-
80-82	4,286,748	1,489,967	35	6,525	0	1,483,442-	35-
81-83	1,149,786	998,117	87	2,527	0	995,590-	87-
82-84	1,168,602	1,028,328	88	707	0	1,027,621-	88-
83-85	1,229,250	703,469	57	2,279	0	701,190-	57-
84-86	1,281,048	306,859	24	3,142	0	303,718-	24-
85-87	1,367,372		0	4,738	0	4,738	0
86-88	1,560,049	9,638	1	6,584	0	3,054-	0
87-89	1,605,821	26,572	2	7,409	0	19,163-	1-
88-90	1,761,882	694,615	39	10,370	1	684,245-	39-
89-91	1,851,683	1,523,086	82	11,697	1	1,511,389-	82-
90-92	1,999,288	2,447,400	122	13,883	1	2,433,517-	122-
91-93	1,967,521	2,777,116	141	10,964	1	2,766,152-	141-
92-94	1,930,455	2,981,372	154	7,125	0	2,974,247-	154-
93-95	1,559,476	3,065,063	197	4,057	0	3,061,006-	196-
94-96	1,568,706	3,151,015	201	4,127	0	3,146,888-	201-
95-97	1,590,553	2,901,322	182	3,100	0	2,898,221-	182-
96-98	2,158,637	2,841,968	132	1,947	0	2,840,021-	132-
97-99	1,955,621	2,400,836	123		0	2,400,836-	123-
98-00	1,488,856	2,396,065	161		0	2,396,065-	161-
99-01	1,371,409	2,094,932	153		0	2,094,932-	153-
00-02	1,782,582	2,262,079	127	51,178	3	2,210,902-	124-
01-03	2,137,816	2,318,304	108	77,303	4	2,241,001-	105-
02-04	1,978,507	2,316,435	117	87,296	4	2,229,139-	113-
03-05	2,413,999	2,350,758	97	60,216	2	2,290,542-	95-
04-06	2,609,360	2,255,315	86	36,609	1	2,218,706-	85-
05-07	3,272,830	2,848,290	87	29,938	1	2,818,352-	86-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	2,838,452	3,821,279	135	9,589	0	3,811,689-	134-
07-09	2,643,539	4,971,892	188	30,823	1	4,941,069-	187-
08-10	4,674,382	5,956,727	127	27,663	1	5,929,064-	127-
09-11	4,840,075	6,154,148	127	29,117	1	6,125,031-	127-
10-12	5,256,072	7,665,344	146	21,526	0	7,643,817-	145-
11-13	2,183,498	6,418,474	294	26,041	1	6,392,433-	293-
12-14	7,881,673	5,558,679	71	30,712	0	5,527,967-	70-
13-15	10,494,768	5,628,003	54	18,809	0	5,609,194-	53-
14-16	16,183,726	8,958,459	55	42,296	0	8,916,163-	55-
15-17	15,050,501	10,956,406	73	90,336	1	10,866,070-	72-
16-18	19,274,713	12,485,187	65	151,267	1	12,333,919-	64-
17-19	27,247,121	16,094,227	59	213,596	1	15,880,631-	58-
18-20	30,047,743	14,819,022	49	174,144	1	14,644,878-	49-
19-21	34,916,224	15,602,741	45	124,265	0	15,478,476-	44-
20-22	31,990,556	8,917,557	28	74,549	0	8,843,008-	28-
FIVE-YEAR AVERAGE							
18-22	32,240,847	13,115,503	41	138,139	0	12,977,365-	40-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	39,977	9,649	24	9,446	24	203-	1-
1976	68,822	17,448	25	6,761	10	10,687-	16-
1977	160,765	137,153	85	3,794	2	133,359-	83-
1978	35,985	22,714	63	2,386	7	20,328-	56-
1979	43,166	26,581	62	6,677	15	19,904-	46-
1980	32,975	29,699	90	681	2	29,018-	88-
1981	27,815	26,056	94	1,229	4	24,827-	89-
1982	173,903	54,891	32	6,694	4	48,197-	28-
1983	75,318-	55,624	74-	1,863-	2	57,487-	76
1984	201,416	114,973	57	4,010	2	110,963-	55-
1985	79,165	80,320	101	1,737	2	78,583-	99-
1986	54,997	93,826	171	2,096	4	91,730-	167-
1987	40,991	103,282	252	1,016	2	102,266-	249-
1988	34,380	99,450	289	357	1	99,093-	288-
1989	54,647	124,435	228	39-	0	124,474-	228-
1990	33,720	2,035	6		0	2,035-	6-
1991	81,795	2,016	2		0	2,016-	2-
1992	89,328	72,402	81		0	72,402-	81-
1993	9,860		0		0		0
1994	105,024	5,021	5		0	5,021-	5-
1995	36,741		0		0		0
1996	1,263		0		0		0
1997	5,549	292,307			0	292,307-	
1998	269	38,466			0	38,466-	
1999		41,164				41,164-	
2000		47,384				47,384-	
2001		9,377				9,377-	
2002		4,922				4,922-	
2003		7,793				7,793-	
2004		5,716		177		5,539-	
2005		30,870				30,870-	
2006		22,263				22,263-	
2007		11,371				11,371-	
2008	153	69,985			0	69,985-	
2009		214,026				214,026-	
2010		190,808				190,808-	
2011		12,049-				12,049	
2012		551,333				551,333-	
2013		41,777				41,777-	
2014							
2015		171,843				171,843-	
2016		273,526		200-		273,726-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017		300,408		4,094		296,314-	
2018	130,783	540	0		0	540-	0
2019				8,778		8,778	
2020		103,500		3,629		99,871-	
2021		1,024,774				1,024,774-	
2022							
TOTAL	1,468,171	4,519,680	308	61,460	4	4,458,220-	304-
THREE-YEAR MOVING AVERAGES							
75-77	89,855	54,750	61	6,667	7	48,083-	54-
76-78	88,524	59,105	67	4,314	5	54,791-	62-
77-79	79,972	62,149	78	4,286	5	57,864-	72-
78-80	37,375	26,331	70	3,248	9	23,083-	62-
79-81	34,652	27,445	79	2,862	8	24,583-	71-
80-82	78,231	36,882	47	2,868	4	34,014-	43-
81-83	42,133	45,524	108	2,020	5	43,504-	103-
82-84	100,000	75,163	75	2,947	3	72,216-	72-
83-85	68,421	83,639	122	1,295	2	82,344-	120-
84-86	111,859	96,373	86	2,614	2	93,759-	84-
85-87	58,384	92,476	158	1,616	3	90,860-	156-
86-88	43,456	98,853	227	1,156	3	97,696-	225-
87-89	43,339	109,056	252	445	1	108,611-	251-
88-90	40,916	75,307	184	106	0	75,201-	184-
89-91	56,721	42,829	76	13-	0	42,842-	76-
90-92	68,281	25,484	37		0	25,484-	37-
91-93	60,328	24,806	41		0	24,806-	41-
92-94	68,071	25,808	38		0	25,808-	38-
93-95	50,542	1,674	3		0	1,674-	3-
94-96	47,676	1,674	4		0	1,674-	4-
95-97	14,518	97,436	671		0	97,436-	671-
96-98	2,360	110,258			0	110,258-	
97-99	1,939	123,979			0	123,979-	
98-00	90	42,338			0	42,338-	
99-01		32,642				32,642-	
00-02		20,561				20,561-	
01-03		7,364				7,364-	
02-04		6,144		59		6,085-	
03-05		14,793		59		14,734-	
04-06		19,616		59		19,557-	
05-07		21,501				21,501-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	51	34,540			0	34,540-	
07-09	51	98,461			0	98,461-	
08-10	51	158,273			0	158,273-	
09-11		130,929				130,929-	
10-12		243,364				243,364-	
11-13		193,687				193,687-	
12-14		197,703				197,703-	
13-15		71,207				71,207-	
14-16		148,456		67-		148,523-	
15-17		248,592		1,298		247,294-	
16-18	43,594	191,491	439	1,298	3	190,193-	436-
17-19	43,594	100,316	230	4,291	10	96,025-	220-
18-20	43,594	34,680	80	4,136	9	30,544-	70-
19-21		376,091		4,136		371,956-	
20-22		376,091		1,210		374,882-	
FIVE-YEAR AVERAGE							
18-22	26,157	225,763	863	2,481	9	223,281-	854-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	59,571	4,452	7		0	4,452-	7-
1976	63,311	6,044	10		0	6,044-	10-
1977	145,610	48,306	33		0	48,306-	33-
1978	17,625	10,249	58	27	0	10,222-	58-
1979	358,712	145,065	40	9	0	145,056-	40-
1980	18,845	1,324	7	2	0	1,322-	7-
1981	62,425	72,918	117		0	72,918-	117-
1982	784,083	14,461	2	200	0	14,261-	2-
1983	95,309	82,021	86	2	0	82,019-	86-
1984	484,572	58,956	12	2	0	58,954-	12-
1985	3,838		0	650	17	650	17
1986	17,481		0	108	1	108	1
1987	102,815		0		0		0
1988	121,885		0		0		0
1989	12,506		0		0		0
1990	1,531		0		0		0
1991		144,373				144,373-	
1992	97,837	268,087	274		0	268,087-	274-
1993							
1994	1,440,932		0		0		0
1995	14,014		0		0		0
1996							
1997							
1998	101		0		0		0
1999		57,181				57,181-	
2000		8,103				8,103-	
2001		5,014				5,014-	
2002							
2003							
2004							
2005	88,482		0		0		0
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014				1,579		1,579	
2015							
2016				2,445		2,445	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017							
2018	979,832		0		0		0
2019	114,658		0		0		0
2020							
2021							
2022							
TOTAL	5,085,975	926,554	18	5,023	0	921,531-	18-
THREE-YEAR MOVING AVERAGES							
75-77	89,497	19,601	22		0	19,601-	22-
76-78	75,515	21,533	29	9	0	21,524-	29-
77-79	173,982	67,873	39	12	0	67,861-	39-
78-80	131,727	52,213	40	13	0	52,200-	40-
79-81	146,661	73,102	50	4	0	73,099-	50-
80-82	288,451	29,568	10	67	0	29,500-	10-
81-83	313,939	56,467	18	67	0	56,399-	18-
82-84	454,655	51,813	11	68	0	51,745-	11-
83-85	194,573	46,992	24	218	0	46,774-	24-
84-86	168,630	19,652	12	253	0	19,399-	12-
85-87	41,378		0	253	1	253	1
86-88	80,727		0	36	0	36	0
87-89	79,069		0		0		0
88-90	45,307		0		0		0
89-91	4,679	48,124			0	48,124-	
90-92	33,123	137,487	415		0	137,487-	415-
91-93	32,612	137,487	422		0	137,487-	422-
92-94	512,923	89,362	17		0	89,362-	17-
93-95	484,982		0		0		0
94-96	484,982		0		0		0
95-97	4,671		0		0		0
96-98	34		0		0		0
97-99	34	19,060			0	19,060-	
98-00	34	21,761			0	21,761-	
99-01		23,433				23,433-	
00-02		4,372				4,372-	
01-03		1,671				1,671-	
02-04							
03-05	29,494		0		0		0
04-06	29,494		0		0		0
05-07	29,494		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08							
07-09							
08-10							
09-11							
10-12							
11-13							
12-14				526		526	
13-15				526		526	
14-16				1,341		1,341	
15-17				815		815	
16-18	326,611		0	815	0	815	0
17-19	364,830		0		0		0
18-20	364,830		0		0		0
19-21	38,219		0		0		0
20-22							
FIVE-YEAR AVERAGE							
18-22	218,898		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	555,776	557,660	100	2,984	1	554,676-	100-
1976	595,248	958,508	161	2,884	0	955,624-	161-
1977	832,790	1,396,245	168	3,206	0	1,393,039-	167-
1978	882,663	1,186,507	134	2,182	0	1,184,325-	134-
1979	985,207	1,218,531	124	2,834	0	1,215,697-	123-
1980	7,399,668	1,978,073	27	68,283	1	1,909,790-	26-
1981	2,227,912	1,594,384	72	28,694	1	1,565,690-	70-
1982	2,200,765	1,651,410	75	25,564	1	1,625,846-	74-
1983	1,989,784	1,606,685	81	22,821	1	1,583,864-	80-
1984	1,851,318	1,701,056	92	20,809	1	1,680,247-	91-
1985	2,130,807	1,938,713	91	25,836	1	1,912,877-	90-
1986	2,145,813	2,120,807	99	24,943	1	2,095,864-	98-
1987	4,750,512	2,212,453	47	97,953	2	2,114,500-	45-
1988	1,266,885	2,226,180	176	6,398	1	2,219,782-	175-
1989	2,001,344	2,022,310	101	7,524	0	2,014,786-	101-
1990	2,966,533	2,188,859	74		0	2,188,859-	74-
1991	2,725,821	2,379,900	87		0	2,379,900-	87-
1992	2,425,329	2,667,272	110		0	2,667,272-	110-
1993	2,934,036	2,584,026	88		0	2,584,026-	88-
1994	2,924,209	2,675,475	91		0	2,675,475-	91-
1995	3,308,631	2,789,288	84		0	2,789,288-	84-
1996	2,744,931	2,772,455	101		0	2,772,455-	101-
1997	2,515,591	2,839,525	113		0	2,839,525-	113-
1998	1,564,041	3,300,625	211		0	3,300,625-	211-
1999		3,407,493				3,407,493-	
2000	3,455,016	2,294,701	66		0	2,294,701-	66-
2001	778,674	2,025,894	260		0	2,025,894-	260-
2002	185,291	2,470,744		13,225	7	2,457,519-	
2003	2,977,996	3,200,234	107	74,902	3	3,125,332-	105-
2004	3,072,378	3,997,851	130		0	3,997,851-	130-
2005	3,675,377	4,029,983	110		0	4,029,983-	110-
2006	3,094,926	4,920,460	159		0	4,920,460-	159-
2007	4,581,079	5,243,775	114		0	5,243,775-	114-
2008	2,704,003	6,523,573	241		0	6,523,573-	241-
2009	511,082	7,094,295			0	7,094,295-	
2010	19,645,268	5,953,974	30	59,319	0	5,894,655-	30-
2011	2,555,949	6,581,553	257		0	6,581,553-	257-
2012	1,835,968	9,962,747	543	6,909	0	9,955,838-	542-
2013	2,414,952	9,900,800	410	9,783	0	9,891,018-	410-
2014	2,437,094	9,754,840	400	15,024	1	9,739,816-	400-
2015	3,223,529	10,273,477	319	10,748	0	10,262,729-	318-
2016	3,539,126	10,011,122	283		0	10,011,122-	283-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017	2,912,550	11,415,362	392		0	11,415,362-	392-
2018	4,517,677	12,843,048	284		0	12,843,048-	284-
2019	5,233,537	14,871,303	284	332,578	6	14,538,725-	278-
2020	3,663,522	11,526,875	315	14,500	0	11,512,375-	314-
2021	4,238,183	11,824,515	279	72,391	2	11,752,124-	277-
2022	4,961,973	13,315,191	268	194,814	4	13,120,377-	264-
TOTAL	142,140,764	232,010,758	163	1,147,108	1	230,863,650-	162-
THREE-YEAR MOVING AVERAGES							
75-77	661,271	970,804	147	3,025	0	967,780-	146-
76-78	770,234	1,180,420	153	2,757	0	1,177,663-	153-
77-79	900,220	1,267,094	141	2,741	0	1,264,354-	140-
78-80	3,089,179	1,461,037	47	24,433	1	1,436,604-	47-
79-81	3,537,596	1,596,996	45	33,270	1	1,563,726-	44-
80-82	3,942,782	1,741,289	44	40,847	1	1,700,442-	43-
81-83	2,139,487	1,617,493	76	25,693	1	1,591,800-	74-
82-84	2,013,956	1,653,050	82	23,065	1	1,629,986-	81-
83-85	1,990,636	1,748,818	88	23,155	1	1,725,663-	87-
84-86	2,042,646	1,920,192	94	23,863	1	1,896,329-	93-
85-87	3,009,044	2,090,658	69	49,577	2	2,041,080-	68-
86-88	2,721,070	2,186,480	80	43,098	2	2,143,382-	79-
87-89	2,672,914	2,153,648	81	37,292	1	2,116,356-	79-
88-90	2,078,254	2,145,783	103	4,641	0	2,141,142-	103-
89-91	2,564,566	2,197,023	86	2,508	0	2,194,515-	86-
90-92	2,705,894	2,412,010	89		0	2,412,010-	89-
91-93	2,695,062	2,543,733	94		0	2,543,733-	94-
92-94	2,761,191	2,642,258	96		0	2,642,258-	96-
93-95	3,055,625	2,682,930	88		0	2,682,930-	88-
94-96	2,992,590	2,745,739	92		0	2,745,739-	92-
95-97	2,856,384	2,800,423	98		0	2,800,423-	98-
96-98	2,274,854	2,970,868	131		0	2,970,868-	131-
97-99	1,359,877	3,182,548	234		0	3,182,548-	234-
98-00	1,673,019	3,000,940	179		0	3,000,940-	179-
99-01	1,411,230	2,576,029	183		0	2,576,029-	183-
00-02	1,472,994	2,263,780	154	4,408	0	2,259,371-	153-
01-03	1,313,987	2,565,624	195	29,376	2	2,536,248-	193-
02-04	2,078,555	3,222,943	155	29,376	1	3,193,567-	154-
03-05	3,241,917	3,742,689	115	24,967	1	3,717,722-	115-
04-06	3,280,893	4,316,098	132		0	4,316,098-	132-
05-07	3,783,794	4,731,406	125		0	4,731,406-	125-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	3,460,003	5,562,603	161		0	5,562,603-	161-
07-09	2,598,721	6,287,214	242		0	6,287,214-	242-
08-10	7,620,118	6,523,947	86	19,773	0	6,504,174-	85-
09-11	7,570,767	6,543,274	86	19,773	0	6,523,501-	86-
10-12	8,012,395	7,499,425	94	22,076	0	7,477,349-	93-
11-13	2,268,956	8,815,034	389	5,564	0	8,809,470-	388-
12-14	2,229,338	9,872,796	443	10,572	0	9,862,224-	442-
13-15	2,691,858	9,976,372	371	11,852	0	9,964,521-	370-
14-16	3,066,583	10,013,146	327	8,591	0	10,004,556-	326-
15-17	3,225,068	10,566,654	328	3,583	0	10,563,071-	328-
16-18	3,656,451	11,423,178	312		0	11,423,178-	312-
17-19	4,221,255	13,043,238	309	110,859	3	12,932,378-	306-
18-20	4,471,579	13,080,409	293	115,693	3	12,964,716-	290-
19-21	4,378,414	12,740,898	291	139,823	3	12,601,075-	288-
20-22	4,287,893	12,222,194	285	93,902	2	12,128,292-	283-
FIVE-YEAR AVERAGE							
18-22	4,522,978	12,876,186	285	122,857	3	12,753,330-	282-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 381.00 AND 382.00 METERS AND METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	120,310	24,803	21	44,961	37	20,158	17
1976	157,363	48,418	31	17,269	11	31,149-	20-
1977	266,093	88,794	33	38,980	15	49,814-	19-
1978	209,191	146,498	70	23,559	11	122,939-	59-
1979	199,093	292,672	147	20,098	10	272,574-	137-
1980	528,603	325,905	62	26,133	5	299,772-	57-
1981	55,190	346,489	628	8,577	16	337,912-	612-
1982	801,036	333,067	42	107,390	13	225,677-	28-
1983	1,325,181	266,909	20	170,198	13	96,711-	7-
1984	1,243,157	349,554	28	159,512	13	190,042-	15-
1985	1,154,926	676,343	59	82,143	7	594,200-	51-
1986	852,430	656,813	77	56,201	7	600,612-	70-
1987	1,100,041	670,835	61	9,086	1	661,749-	60-
1988	962,507	689,125	72	9,397	1	679,728-	71-
1989	1,292,951	461,782	36	17,746	1	444,036-	34-
1990	1,420,946		0		0		0
1991	976,768		0		0		0
1992	1,069,828		0		0		0
1993	689,331	680,944	99	9,501	1	671,443-	97-
1994	573,511	791,080	138	7,470	1	783,610-	137-
1995	831,219	91,565	11	6,120	1	85,445-	10-
1996	146,487	427,842	292	16,737	11	411,105-	281-
1997	800,640	241,917	30	9,107	1	232,810-	29-
1998	491,307	204,251	42	5,063	1	199,188-	41-
1999	222,450	1,473	1		0	1,473-	1-
2000	1,104,957	1,345,268	122		0	1,345,268-	122-
2001	732,632	936,746	128		0	936,746-	128-
2002	345,072	1,295,683	375		0	1,295,683-	375-
2003	1,414,090	1,668,390	118		0	1,668,390-	118-
2004	1,559,843	2,241,737	144		0	2,241,737-	144-
2005	1,482,119	1,820,692	123		0	1,820,692-	123-
2006	1,245,089	2,310,630	186		0	2,310,630-	186-
2007	1,961,770	2,649,533	135		0	2,649,533-	135-
2008	1,291,939	2,098,233	162		0	2,098,233-	162-
2009	251,973	1,398,696	555		0	1,398,696-	555-
2010	20,681,356	660,667	3	85,984	0	574,682-	3-
2011	9,402,862	1,465,241	16	181,688	2	1,283,553-	14-
2012	9,652,100	1,716,868	18	144,168	1	1,572,700-	16-
2013	4,157,576	1,433,874	34	140,618	3	1,293,256-	31-
2014	3,887,164	1,256,483	32	109,196	3	1,147,287-	30-
2015	6,035,001	2,229,231	37	78,121	1	2,151,110-	36-
2016	35,405,695	4,812,727	14		0	4,812,727-	14-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 381.00 AND 382.00 METERS AND METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017	63,708,640	8,637,347	14		0	8,637,347-	14-
2018	41,114,759	9,889,499	24		0	9,889,499-	24-
2019	38,182,030	8,383,283	22	221,719	1	8,161,564-	21-
2020	26,690,767	5,278,639	20	9,666	0	5,268,973-	20-
2021	39,659,681	9,483,263	24	48,822	0	9,434,441-	24-
2022	35,498,403	6,334,292	18	131,386	0	6,202,906-	17-
TOTAL	362,956,079	87,164,102	24	1,996,616	1	85,167,485-	23-
THREE-YEAR MOVING AVERAGES							
75-77	181,255	54,005	30	33,737	19	20,268-	11-
76-78	210,882	94,570	45	26,603	13	67,967-	32-
77-79	224,792	175,988	78	27,546	12	148,442-	66-
78-80	312,296	255,025	82	23,263	7	231,762-	74-
79-81	260,962	321,689	123	18,269	7	303,419-	116-
80-82	461,610	335,154	73	47,367	10	287,787-	62-
81-83	727,136	315,488	43	95,388	13	220,100-	30-
82-84	1,123,125	316,510	28	145,700	13	170,810-	15-
83-85	1,241,088	430,935	35	137,284	11	293,651-	24-
84-86	1,083,504	560,903	52	99,285	9	461,618-	43-
85-87	1,035,799	667,997	64	49,143	5	618,854-	60-
86-88	971,659	672,258	69	24,895	3	647,363-	67-
87-89	1,118,500	607,247	54	12,076	1	595,171-	53-
88-90	1,225,468	383,636	31	9,048	1	374,588-	31-
89-91	1,230,222	153,927	13	5,915	0	148,012-	12-
90-92	1,155,847		0		0		0
91-93	911,976	226,981	25	3,167	0	223,814-	25-
92-94	777,557	490,675	63	5,657	1	485,018-	62-
93-95	698,020	521,196	75	7,697	1	513,499-	74-
94-96	517,072	436,829	84	10,109	2	426,720-	83-
95-97	592,782	253,775	43	10,655	2	243,120-	41-
96-98	479,478	291,337	61	10,302	2	281,034-	59-
97-99	504,799	149,214	30	4,723	1	144,490-	29-
98-00	606,238	516,997	85	1,688	0	515,310-	85-
99-01	686,680	761,162	111		0	761,162-	111-
00-02	727,554	1,192,566	164		0	1,192,566-	164-
01-03	830,598	1,300,273	157		0	1,300,273-	157-
02-04	1,106,335	1,735,270	157		0	1,735,270-	157-
03-05	1,485,351	1,910,273	129		0	1,910,273-	129-
04-06	1,429,017	2,124,353	149		0	2,124,353-	149-
05-07	1,562,993	2,260,285	145		0	2,260,285-	145-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 381.00 AND 382.00 METERS AND METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	1,499,599	2,352,799	157		0	2,352,799-	157-
07-09	1,168,561	2,048,821	175		0	2,048,821-	175-
08-10	7,408,423	1,385,865	19	28,662	0	1,357,204-	18-
09-11	10,112,064	1,174,868	12	89,224	1	1,085,644-	11-
10-12	13,245,440	1,280,925	10	137,280	1	1,143,645-	9-
11-13	7,737,513	1,538,661	20	155,491	2	1,383,170-	18-
12-14	5,898,947	1,469,075	25	131,327	2	1,337,748-	23-
13-15	4,693,247	1,639,863	35	109,312	2	1,530,551-	33-
14-16	15,109,287	2,766,147	18	62,439	0	2,703,708-	18-
15-17	35,049,779	5,226,435	15	26,040	0	5,200,395-	15-
16-18	46,743,031	7,779,858	17		0	7,779,858-	17-
17-19	47,668,476	8,970,043	19	73,906	0	8,896,137-	19-
18-20	35,329,185	7,850,474	22	77,128	0	7,773,345-	22-
19-21	34,844,159	7,715,062	22	93,402	0	7,621,659-	22-
20-22	33,949,617	7,032,065	21	63,291	0	6,968,773-	21-
FIVE-YEAR AVERAGE							
18-22	36,229,128	7,873,795	22	82,319	0	7,791,477-	22-

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 383.00 AND 384.00 HOUSE REGULATORS AND HOUSE REGULATOR INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	65,292	1,066	2	925	1	141-	0
1976	48,660	4,494	9	944	2	3,550-	7-
1977	54,260	7,383	14	881	2	6,502-	12-
1978	35,153	6,222	18	260	1	5,962-	17-
1979	43,702	9,676	22	2,016	5	7,660-	18-
1980	73,512	30,961	42	5,134	7	25,827-	35-
1981	48,864	45,748	94	3,392	7	42,356-	87-
1982	32,924	15,219	46	3,179	10	12,040-	37-
1983	32,847	4,086	12	2,044	6	2,042-	6-
1984	27,334	2,797	10	1,903	7	894-	3-
1985	26,464	22,272	84	1,402	5	20,870-	79-
1986	15,484	4,039	26	572	4	3,467-	22-
1987	26,390	7,107	27	279	1	6,828-	26-
1988	13,384	14,436	108	274	2	14,162-	106-
1989	14,743	231,614		1,081	7	230,533-	
1990	27,756		0		0		0
1991	24,539		0		0		0
1992	34,304		0		0		0
1993	9,672	126,640		602	6	126,038-	
1994	19,090	169,452	888	2,780	15	166,672-	873-
1995	7,934	30,884	389	1,322	17	29,562-	373-
1996	24,708	140,368	568		0	140,368-	568-
1997	690	489,500			0	489,500-	
1998		248,399				248,399-	
1999	600	3,649	608		0	3,649-	608-
2000	1,230		0		0		0
2001							
2002							
2003							
2004							
2005							
2006	5,330		0		0		0
2007							
2008	192		0		0		0
2009							
2010							
2011							
2012		4,701				4,701-	
2013		368				368-	
2014		32,977				32,977-	
2015		40,219				40,219-	
2016		14,899				14,899-	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 383.00 AND 384.00 HOUSE REGULATORS AND HOUSE REGULATOR INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017							
2018							
2019							
2020							
2021							
2022							
TOTAL	715,058	1,709,177	239	28,990	4	1,680,187-	235-
THREE-YEAR MOVING AVERAGES							
75-77	56,071	4,314	8	917	2	3,398-	6-
76-78	46,024	6,033	13	695	2	5,338-	12-
77-79	44,372	7,760	17	1,052	2	6,708-	15-
78-80	50,789	15,620	31	2,470	5	13,150-	26-
79-81	55,359	28,795	52	3,514	6	25,281-	46-
80-82	51,767	30,643	59	3,902	8	26,741-	52-
81-83	38,212	21,684	57	2,872	8	18,813-	49-
82-84	31,035	7,367	24	2,375	8	4,992-	16-
83-85	28,882	9,718	34	1,783	6	7,935-	27-
84-86	23,094	9,703	42	1,292	6	8,410-	36-
85-87	22,779	11,139	49	751	3	10,388-	46-
86-88	18,419	8,527	46	375	2	8,152-	44-
87-89	18,172	84,386	464	545	3	83,841-	461-
88-90	18,628	82,017	440	452	2	81,565-	438-
89-91	22,346	77,205	345	360	2	76,844-	344-
90-92	28,866		0		0		0
91-93	22,838	42,213	185	201	1	42,013-	184-
92-94	21,022	98,697	469	1,127	5	97,570-	464-
93-95	12,232	108,992	891	1,568	13	107,424-	878-
94-96	17,244	113,568	659	1,367	8	112,201-	651-
95-97	11,111	220,251		441	4	219,810-	
96-98	8,466	292,756			0	292,756-	
97-99	430	247,183			0	247,183-	
98-00	610	84,016			0	84,016-	
99-01	610	1,216	199		0	1,216-	199-
00-02	410		0		0		0
01-03							
02-04							
03-05							
04-06	1,777		0		0		0
05-07	1,777		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNTS 383.00 AND 384.00 HOUSE REGULATORS AND HOUSE REGULATOR INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	1,841		0		0		0
07-09	64		0		0		0
08-10	64		0		0		0
09-11							
10-12		1,567				1,567-	
11-13		1,690				1,690-	
12-14		12,682				12,682-	
13-15		24,521				24,521-	
14-16		29,365				29,365-	
15-17		18,373				18,373-	
16-18		4,966				4,966-	
17-19							
18-20							
19-21							
20-22							
FIVE-YEAR AVERAGE							
18-22							

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1975	3,813		0	3-	0	3-	0
1976	4,400		0	635	14	635	14
1977	5,983		0	560	9	560	9
1978	96		0		0		0
1979	2,038		0	150	7	150	7
1980	4,479		0	558	12	558	12
1981	2,568-		0	329-	13	329-	13
1982	19,404		0	2,875	15	2,875	15
1983	5,215		0	669	13	669	13
1984	1,465		0	188	13	188	13
1985	12,075		0	795	7	795	7
1986	47,635		0	3,137	7	3,137	7
1987	30,421		0	8,187	27	8,187	27
1988	3,238		0	8,321	257	8,321	257
1989							
1990	8,045		0		0		0
1991	975		0		0		0
1992	5,571		0		0		0
1993	3,306		0		0		0
1994	15,557		0		0		0
1995	40,764		0		0		0
1996	15,147		0		0		0
1997	37,733		0		0		0
1998	55,866		0		0		0
1999							
2000							
2001							
2002							
2003							
2004							
2005	36,636		0		0		0
2006	120,354		0		0		0
2007	259,657		0		0		0
2008	348,741		0		0		0
2009							
2010	1,572,064		0	702	0	702	0
2011				783		783	
2012	754,940		0	55	0	55	0
2013	811,588		0		0		0
2014	1,512,986		0	304	0	304	0
2015	1,829,687		0	218	0	218	0
2016	2,363,801		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2017	4,051,188		0		0		0
2018	2,100,215		0		0		0
2019	3,207,290		0		0		0
2020	2,450,683		0		0		0
2021	2,574,018		0		0		0
2022	3,197,563		0		0		0
TOTAL	27,512,070		0	27,804	0	27,804	0
THREE-YEAR MOVING AVERAGES							
75-77	4,732		0	397	8	397	8
76-78	3,493		0	398	11	398	11
77-79	2,706		0	237	9	237	9
78-80	2,204		0	236	11	236	11
79-81	1,316		0	126	10	126	10
80-82	7,105		0	1,035	15	1,035	15
81-83	7,350		0	1,072	15	1,072	15
82-84	8,695		0	1,244	14	1,244	14
83-85	6,252		0	551	9	551	9
84-86	20,392		0	1,373	7	1,373	7
85-87	30,044		0	4,040	13	4,040	13
86-88	27,098		0	6,548	24	6,548	24
87-89	11,220		0	5,503	49	5,503	49
88-90	3,761		0	2,774	74	2,774	74
89-91	3,007		0		0		0
90-92	4,864		0		0		0
91-93	3,284		0		0		0
92-94	8,145		0		0		0
93-95	19,876		0		0		0
94-96	23,823		0		0		0
95-97	31,215		0		0		0
96-98	36,249		0		0		0
97-99	31,200		0		0		0
98-00	18,622		0		0		0
99-01							
00-02							
01-03							
02-04							
03-05	12,212		0		0		0
04-06	52,330		0		0		0
05-07	138,882		0		0		0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
06-08	242,917		0		0		0
07-09	202,799		0		0		0
08-10	640,268		0	234	0	234	0
09-11	524,021		0	495	0	495	0
10-12	775,668		0	513	0	513	0
11-13	522,176		0	279	0	279	0
12-14	1,026,505		0	120	0	120	0
13-15	1,384,754		0	174	0	174	0
14-16	1,902,158		0	174	0	174	0
15-17	2,748,225		0	73	0	73	0
16-18	2,838,401		0		0		0
17-19	3,119,564		0		0		0
18-20	2,586,063		0		0		0
19-21	2,743,997		0		0		0
20-22	2,740,755		0		0		0
FIVE-YEAR AVERAGE							
18-22	2,705,954		0		0		0

PART IX. DETAILED DEPRECIATION CALCULATIONS

ELECTRIC PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. 0						
1943	4,509.42	3,811	4,509			
1950	2,483.58	2,022	2,484			
1951	1,034.98	838	1,035			
1952	26.09	21	26			
1953	1,772.46	1,417	1,772			
1954	16,470.26	13,077	16,470			
1955	2,220.19	1,751	2,220			
1957	5,499.13	4,275	5,499			
1958	660.43	510	660			
1959	1,684.56	1,290	1,685			
1961	8,359.44	6,295	8,359			
1963	3,075.36	2,275	3,075			
1965	6,197.58	4,499	6,198			
1966	6,758.94	4,857	6,759			
1967	3,837.83	2,730	3,838			
1968	28,455.42	20,020	28,455			
1970	10,590.38	7,283	10,590			
1973	4,027.48	2,667	4,027			
1974	5,398.40	3,526	5,398			
1975	15,540.70	10,006	15,541			
1976	11,465.04	7,274	11,316	149	23.76	6
1977	18,158.31	11,345	17,649	509	24.39	21
1978	1,317.99	810	1,260	58	25.03	2
1979	972.02	588	915	57	25.69	2
1980	7,905.22	4,698	7,308	597	26.37	23
1981	9,998.65	5,836	9,079	920	27.06	34
1983	9,177.78	5,157	8,023	1,155	28.48	41
1984	3,883.90	2,138	3,326	558	29.22	19
1985	31,697.92	17,083	26,575	5,123	29.97	171
1986	37,044.68	19,526	30,376	6,669	30.74	217
1987	9,851.44	5,074	7,893	1,958	31.52	62
1988	10,689.33	5,376	8,363	2,326	32.31	72
1989	3,782.78	1,855	2,886	897	33.13	27
1990	1,099.83	525	817	283	33.95	8
1991	3,344.00	1,554	2,417	927	34.79	27
1992	62,340.83	28,159	43,806	18,535	35.64	520
1998	303,656.40	112,213	174,565	129,091	40.98	3,150

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. 0						
2003	9,251.85	2,749	4,277	4,975	45.69	109
2008	1,524.03	339	527	997	50.56	20
2009	552,481.66	114,408	177,980	374,501	51.54	7,266
	1,218,246.29	439,877	667,958	550,288		11,797

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.6 0.97

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S1.5						
NET SALVAGE PERCENT.. -10						
1925	2,518.73	2,334	2,615	156	11.03	14
1928	10,894.00	9,950	11,147	836	11.88	70
1938	60,313.28	52,204	58,482	7,863	14.92	527
1943	2,049,152.86	1,719,854	1,926,674	327,394	16.59	19,734
1945	10,093.64	8,361	9,366	1,737	17.29	100
1950	21,994.82	17,582	19,696	4,498	19.13	235
1951	96,272.20	76,368	85,552	20,347	19.52	1,042
1952	70,857.00	55,773	62,480	15,463	19.91	777
1953	121,328.41	94,739	106,132	27,329	20.31	1,346
1954	214,160.36	165,879	185,827	49,749	20.71	2,402
1955	202,617.55	155,634	174,350	48,529	21.12	2,298
1956	237,647.62	180,973	202,736	58,676	21.54	2,724
1957	280,325.65	211,623	237,072	71,286	21.96	3,246
1958	36,582.17	27,369	30,660	9,580	22.39	428
1959	37,264.52	27,622	30,944	10,047	22.83	440
1960	8,247.65	6,056	6,784	2,288	23.27	98
1961	257,494.97	187,264	209,783	73,461	23.72	3,097
1962	183,102.43	131,839	147,693	53,720	24.18	2,222
1963	52,016.80	37,070	41,528	15,690	24.65	637
1964	65,637.81	46,291	51,858	20,344	25.12	810
1965	69,980.68	48,815	54,685	22,294	25.61	871
1966	45,868.88	31,643	35,448	15,008	26.10	575
1967	256,525.24	174,950	195,989	86,189	26.60	3,240
1968	217,888.21	146,888	164,552	75,125	27.10	2,772
1969	219,827.90	146,399	164,004	77,807	27.62	2,817
1970	85,081.63	55,954	62,683	30,907	28.15	1,098
1971	225,971.19	146,727	164,372	84,196	28.68	2,936
1972	253,373.41	162,330	181,851	96,860	29.23	3,314
1973	315,902.97	199,659	223,669	123,824	29.78	4,158
1974	583,589.21	363,709	407,447	234,501	30.34	7,729
1975	1,689,273.10	1,037,415	1,162,169	696,031	30.92	22,511
1976	833,441.46	504,232	564,868	351,918	31.50	11,172
1977	1,743,431.86	1,038,609	1,163,506	754,269	32.09	23,505
1978	1,531,681.77	897,789	1,005,752	679,098	32.70	20,768
1979	316,029.77	182,208	204,119	143,514	33.31	4,308
1980	897,036.92	508,310	569,436	417,305	33.94	12,295
1981	785,200.71	437,164	489,735	373,986	34.57	10,818
1982	2,487,987.98	1,359,800	1,523,322	1,213,465	35.22	34,454
1983	1,967,817.79	1,055,394	1,182,310	982,290	35.87	27,385
1984	705,798.39	371,109	415,736	360,642	36.54	9,870
1985	1,889,556.17	973,346	1,090,395	988,117	37.22	26,548

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S1.5						
NET SALVAGE PERCENT.. -10						
1986	3,801,552.26	1,917,020	2,147,550	2,034,157	37.91	53,658
1987	1,539,225.88	759,259	850,563	842,585	38.61	21,823
1988	11,872,503.83	5,723,960	6,412,291	6,647,463	39.32	169,061
1989	9,351,324.77	4,401,164	4,930,423	5,356,034	40.05	133,734
1990	3,790,264.99	1,740,387	1,949,676	2,219,615	40.78	54,429
1991	1,847,920.54	826,725	926,142	1,106,571	41.53	26,645
1992	4,223,261.65	1,839,002	2,060,150	2,585,438	42.29	61,136
1993	5,436,649.42	2,301,584	2,578,360	3,401,954	43.06	79,005
1994	6,029,141.08	2,478,465	2,776,511	3,855,544	43.84	87,946
1995	17,357,079.44	6,919,799	7,751,935	11,340,852	44.63	254,108
1996	875,185.75	337,909	378,544	584,160	45.43	12,858
1997	1,671,663.80	623,897	698,923	1,139,907	46.25	24,647
1998	6,108,393.64	2,201,019	2,465,701	4,253,532	47.07	90,366
1999	4,885,868.49	1,696,017	1,899,971	3,474,484	47.91	72,521
2000	3,201,868.51	1,069,190	1,197,765	2,324,290	48.75	47,678
2001	4,238,200.03	1,358,000	1,521,305	3,140,715	49.61	63,308
2002	20,036,055.52	6,145,980	6,885,061	15,154,600	50.48	300,210
2003	10,751,809.28	3,149,409	3,528,139	8,298,851	51.36	161,582
2004	492,935.67	137,569	154,112	388,117	52.24	7,429
2005	3,225,992.99	854,714	957,497	2,591,095	53.14	48,760
2006	6,090,838.02	1,526,644	1,710,230	4,989,692	54.05	92,316
2007	6,390,672.70	1,510,410	1,692,044	5,337,696	54.96	97,120
2008	8,822,882.88	1,956,271	2,191,521	7,513,650	55.89	134,436
2009	4,535,365.32	939,360	1,052,322	3,936,580	56.82	69,282
2010	452,950.41	87,123	97,600	400,645	57.76	6,936
2011	88,561.92	15,713	17,603	79,815	58.71	1,359
2012	5,174,986.96	840,837	941,951	4,750,535	59.66	79,627
2013	86,866.27	12,804	14,344	81,209	60.62	1,340
2014	1,341,616.91	177,300	198,621	1,277,158	61.59	20,736
2015	1,639,889.12	191,734	214,791	1,589,087	62.56	25,401
2016	4,313,338.41	437,886	490,544	4,254,128	63.54	66,952
2017	10,378,104.31	892,040	999,312	10,416,603	64.53	161,423
2018	25,992,493.44	1,829,872	2,049,922	26,541,821	65.52	405,095
2019	10,041,771.19	550,751	616,981	10,428,967	66.51	156,803
2020	1,636,215.38	64,272	72,001	1,727,836	67.50	25,598
2021	11,301,694.20	266,415	298,452	12,133,412	68.50	177,130
2022	1,446,917.25	11,364	12,731	1,578,878	69.50	22,718
	241,611,849.94	70,849,100	79,369,016	186,404,019		3,590,567

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.9 1.49

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. -15						
1925	16,223.47	18,657	18,657			
1926	16,542.42	19,024	19,024			
1928	67,166.67	77,242	77,242			
1929	22,323.62	25,672	25,672			
1930	6,982.94	8,030	8,030			
1931	74,527.10	85,706	85,706			
1937	25,489.07	28,238	20,998	8,314	1.65	5,039
1938	133,891.97	147,064	109,358	44,618	2.02	22,088
1939	10,842.00	11,806	8,779	3,689	2.39	1,544
1940	78,894.00	85,164	63,329	27,399	2.76	9,927
1941	5,488.21	5,872	4,366	1,945	3.13	621
1942	59,769.52	63,374	47,126	21,609	3.51	6,156
1943	1,821,272.94	1,913,879	1,423,180	671,284	3.88	173,011
1944	9,781.44	10,184	7,573	3,676	4.26	863
1945	12,452.13	12,843	9,550	4,770	4.64	1,028
1946	10,076.00	10,295	7,655	3,932	5.02	783
1947	13,007.07	13,163	9,788	5,170	5.40	957
1948	45,634.00	45,739	34,012	18,467	5.78	3,195
1949	13,594.00	13,493	10,034	5,599	6.16	909
1950	140,148.00	137,710	102,403	58,767	6.55	8,972
1951	187,555.00	182,472	135,688	80,000	6.93	11,544
1952	1,480,780.00	1,425,887	1,060,304	642,593	7.32	87,786
1953	1,849,159.00	1,762,194	1,310,386	816,147	7.71	105,856
1954	3,521,314.52	3,320,600	2,469,233	1,580,279	8.10	195,096
1955	2,541,433.00	2,370,589	1,762,795	1,159,853	8.50	136,453
1956	1,148,022.95	1,059,402	787,782	532,444	8.89	59,892
1957	1,568,209.00	1,431,138	1,064,209	739,231	9.29	79,573
1958	2,711,091.66	2,447,095	1,819,685	1,298,070	9.68	134,098
1959	1,474,588.02	1,315,922	978,533	717,243	10.08	71,155
1960	1,769,701.00	1,560,741	1,160,583	874,573	10.49	83,372
1961	2,270,739.91	1,979,404	1,471,905	1,139,446	10.89	104,632
1962	2,274,364.02	1,958,736	1,456,536	1,158,983	11.30	102,565
1963	1,481,000.00	1,260,331	937,195	765,955	11.70	65,466
1964	1,096,055.78	921,261	685,059	575,405	12.11	47,515
1965	2,246,541.39	1,864,167	1,386,214	1,197,309	12.53	95,555
1966	915,435.00	750,021	557,723	495,027	12.94	38,256
1967	2,813,729.95	2,275,116	1,691,800	1,543,989	13.36	115,568
1968	4,760,933.82	3,798,497	2,824,602	2,650,472	13.78	192,342
1969	2,054,255.30	1,616,917	1,202,356	1,160,038	14.20	81,693
1970	1,582,563.00	1,228,665	913,648	906,299	14.62	61,990
1971	1,908,733.88	1,460,933	1,086,365	1,108,679	15.05	73,666

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. -15						
1972	2,781,210.62	2,098,145	1,560,202	1,638,190	15.48	105,826
1973	5,643,891.05	4,195,702	3,119,968	3,370,507	15.91	211,848
1974	4,835,550.52	3,540,447	2,632,713	2,928,170	16.35	179,093
1975	9,945,358.71	7,172,359	5,333,441	6,103,722	16.78	363,750
1976	6,721,506.35	4,771,796	3,548,357	4,181,375	17.22	242,821
1977	7,202,711.50	5,030,586	3,740,796	4,542,322	17.67	257,064
1978	6,223,112.52	4,274,840	3,178,815	3,977,764	18.12	219,523
1979	2,209,118.00	1,492,103	1,109,543	1,430,943	18.57	77,057
1980	5,437,894.11	3,610,378	2,684,715	3,568,863	19.02	187,637
1981	3,238,403.33	2,112,011	1,570,513	2,153,651	19.48	110,557
1982	6,506,064.51	4,166,637	3,098,355	4,383,619	19.94	219,840
1983	3,551,630.82	2,232,806	1,660,338	2,424,037	20.40	118,825
1984	5,169,918.00	3,188,045	2,370,663	3,574,743	20.87	171,286
1985	6,371,117.58	3,850,665	2,863,394	4,463,391	21.35	209,058
1986	9,155,877.06	5,423,726	4,033,139	6,496,120	21.82	297,714
1987	11,841,867.85	6,869,539	5,108,260	8,509,888	22.30	381,609
1988	15,477,872.74	8,785,148	6,532,727	11,266,827	22.79	494,376
1989	30,939,799.80	17,173,770	12,770,594	22,810,176	23.28	979,819
1990	17,156,021.07	9,303,607	6,918,259	12,811,165	23.78	538,737
1991	11,724,520.81	6,208,204	4,616,485	8,866,714	24.28	365,186
1992	28,663,973.30	14,811,521	11,014,001	21,949,568	24.78	885,778
1993	15,478,904.70	7,792,808	5,794,813	12,005,927	25.30	474,543
1994	19,834,029.00	9,726,727	7,232,895	15,576,238	25.81	603,496
1995	6,896,677.50	3,288,822	2,445,602	5,485,577	26.34	208,260
1996	10,668,756.79	4,943,086	3,675,730	8,593,340	26.87	319,812
1997	15,582,635.88	7,008,703	5,211,744	12,708,287	27.40	463,806
1998	32,034,910.17	13,958,363	10,379,584	26,460,563	27.95	946,711
1999	9,914,251.49	4,180,547	3,108,698	8,292,691	28.50	290,972
2000	5,686,201.25	2,317,730	1,723,488	4,815,643	29.05	165,771
2001	8,874,760.95	3,488,198	2,593,860	7,612,115	29.62	256,992
2002	30,522,956.98	11,552,222	8,590,352	26,511,049	30.19	878,140
2003	25,385,093.93	9,224,943	6,859,763	22,333,095	30.78	725,572
2004	13,874,115.82	4,832,681	3,593,632	12,361,601	31.37	394,058
2005	11,996,584.20	3,994,791	2,970,568	10,825,504	31.97	338,614
2006	5,687,291.45	1,805,146	1,342,325	5,198,060	32.58	159,548
2007	17,218,329.87	5,192,239	3,861,003	15,940,076	33.20	480,123
2008	20,805,570.71	5,933,749	4,412,397	19,514,009	33.84	576,655
2009	55,426,218.53	14,901,173	11,080,667	52,659,484	34.48	1,527,247
2010	14,890,057.09	3,751,944	2,789,985	14,333,581	35.14	407,899
2011	17,079,616.11	4,011,199	2,982,769	16,658,790	35.81	465,199
2012	18,943,516.87	4,114,977	3,059,940	18,725,104	36.50	513,017

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. -15						
2013	23,217,057.02	4,627,844	3,441,313	23,258,303	37.20	625,223
2014	12,914,018.47	2,336,527	1,737,466	13,113,655	37.92	345,824
2015	79,086,301.25	12,813,839	9,528,504	81,420,742	38.66	2,106,072
2016	187,503,377.58	26,737,982	19,882,640	195,746,244	39.42	4,965,658
2017	190,451,986.17	23,411,025	17,408,681	201,611,103	40.19	5,016,449
2018	176,255,121.43	18,017,415	13,397,937	189,295,453	41.00	4,616,962
2019	30,060,600.51	2,435,089	1,810,757	32,758,934	41.83	783,144
2020	34,333,277.41	2,035,757	1,513,810	37,969,459	42.68	889,631
2021	159,377,257.55	5,784,438	4,301,368	178,982,478	43.58	4,106,987
2022	68,462,746.25	857,393	637,566	78,094,592	44.51	1,754,540
	1,563,499,955.95	384,112,635	285,690,218	1,512,334,731		44,203,495
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					34.2	2.83

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -80						
1926	14,026.05	22,901	9,920	15,327	6.04	2,538
1927	47,862.63	77,842	33,718	52,435	6.27	8,363
1928	44,455.71	72,030	31,200	48,820	6.49	7,522
1929	47,366.51	76,458	33,118	52,142	6.71	7,771
1930	35,442.92	56,986	24,684	39,113	6.94	5,636
1931	2,932.58	4,696	2,034	3,245	7.17	453
1932	10,623.28	16,945	7,340	11,782	7.40	1,592
1933	1,512.46	2,403	1,041	1,681	7.63	220
1934	5,769.76	9,128	3,954	6,432	7.87	817
1935	5,021.30	7,911	3,427	5,611	8.11	692
1936	13,867.05	21,750	9,421	15,540	8.36	1,859
1937	17,909.27	27,971	12,116	20,121	8.60	2,340
1938	122,490.25	190,428	82,485	137,997	8.86	15,575
1939	121,827.54	188,556	81,674	137,616	9.11	15,106
1940	146,671.08	225,909	97,854	166,154	9.38	17,714
1941	180,577.64	276,784	119,891	205,149	9.65	21,259
1942	158,397.53	241,601	104,651	180,465	9.92	18,192
1943	126,247.08	191,549	82,971	144,274	10.21	14,131
1944	112,457.35	169,724	73,517	128,906	10.50	12,277
1945	140,651.57	211,108	91,443	161,730	10.80	14,975
1946	189,932.79	283,445	122,776	219,103	11.11	19,721
1947	188,846.80	280,149	121,348	218,576	11.43	19,123
1948	409,502.94	603,748	261,518	475,587	11.76	40,441
1949	536,958.74	786,452	340,657	625,869	12.11	51,682
1950	558,114.66	812,033	351,738	652,868	12.46	52,397
1951	752,042.68	1,086,488	470,620	883,057	12.83	68,828
1952	847,541.49	1,215,532	526,516	999,059	13.21	75,629
1953	1,066,488.20	1,518,024	657,542	1,262,137	13.60	92,804
1954	390,644.12	551,600	238,929	464,230	14.01	33,136
1955	1,372,030.12	1,921,391	832,263	1,637,391	14.43	113,471
1956	1,530,827.35	2,125,529	920,687	1,834,802	14.86	123,473
1957	1,681,127.56	2,313,763	1,002,222	2,023,808	15.30	132,275
1958	1,660,112.91	2,263,683	980,530	2,007,673	15.76	127,390
1959	1,615,169.59	2,180,915	944,678	1,962,627	16.24	120,851
1960	1,992,886.59	2,664,461	1,154,129	2,433,067	16.72	145,518
1961	1,104,957.16	1,462,017	633,283	1,355,640	17.22	78,725
1962	2,219,682.98	2,905,596	1,258,578	2,736,851	17.73	154,363
1963	2,398,908.00	3,105,012	1,344,957	2,973,077	18.26	162,819
1964	2,915,457.40	3,729,995	1,615,672	3,632,151	18.80	193,200
1965	3,071,469.19	3,882,822	1,681,871	3,846,774	19.35	198,800
1966	2,785,816.38	3,478,487	1,506,730	3,507,739	19.91	176,180

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -80						
1967	3,025,634.70	3,730,172	1,615,749	3,830,393	20.48	187,031
1968	4,093,504.57	4,979,871	2,157,065	5,211,243	21.07	247,330
1969	3,945,447.04	4,734,205	2,050,653	5,051,152	21.67	233,094
1970	4,290,210.25	5,075,379	2,198,435	5,523,943	22.28	247,933
1971	4,237,552.03	4,940,316	2,139,931	5,487,663	22.90	239,636
1972	4,551,639.67	5,227,103	2,264,155	5,928,796	23.53	251,968
1973	4,240,943.30	4,795,107	2,077,033	5,556,665	24.17	229,899
1974	4,193,457.60	4,665,934	2,021,081	5,527,143	24.82	222,689
1975	3,716,382.13	4,067,209	1,761,739	4,927,749	25.48	193,397
1976	4,397,473.57	4,729,799	2,048,744	5,866,708	26.16	224,263
1977	4,378,316.06	4,626,759	2,004,112	5,876,857	26.84	218,959
1978	5,606,183.73	5,817,133	2,519,730	7,571,401	27.53	275,024
1979	6,334,908.35	6,452,294	2,794,855	8,607,980	28.22	305,031
1980	6,734,223.72	6,726,520	2,913,637	9,207,966	28.93	318,284
1981	7,882,926.87	7,718,962	3,343,520	10,845,748	29.64	365,916
1982	6,875,131.73	6,593,155	2,855,869	9,519,368	30.37	313,446
1983	8,951,691.52	8,403,597	3,640,075	12,472,970	31.10	401,060
1984	8,786,469.91	8,068,352	3,494,861	12,320,785	31.84	386,959
1985	11,090,668.44	9,954,052	4,311,665	15,651,538	32.59	480,256
1986	12,443,905.25	10,910,119	4,725,792	17,673,237	33.34	530,091
1987	14,651,576.45	12,537,120	5,430,538	20,942,300	34.10	614,144
1988	15,941,839.45	13,301,424	5,761,601	22,933,710	34.87	657,692
1989	17,242,227.70	14,014,000	6,070,258	24,965,752	35.65	700,302
1990	21,336,146.60	16,874,417	7,309,267	31,095,797	36.44	853,342
1991	16,484,645.62	12,676,923	5,491,095	24,181,267	37.23	649,510
1992	18,666,210.04	13,946,347	6,040,954	27,558,224	38.02	724,835
1993	16,294,637.09	11,808,984	5,115,141	24,215,206	38.83	623,621
1994	19,791,431.28	13,898,928	6,020,414	29,604,162	39.64	746,825
1995	16,474,842.30	11,195,842	4,849,554	24,805,162	40.46	613,079
1996	17,657,540.02	11,598,461	5,023,952	26,759,620	41.28	648,247
1997	15,373,952.70	9,745,087	4,221,150	23,451,965	42.11	556,922
1998	25,408,116.74	15,514,552	6,720,233	39,014,377	42.95	908,367
1999	8,528,300.39	5,009,165	2,169,754	13,181,187	43.79	301,009
2000	13,858,701.58	7,813,730	3,384,570	21,561,093	44.64	482,999
2001	12,885,289.81	6,958,056	3,013,929	20,179,593	45.50	443,508
2002	17,217,852.42	8,887,614	3,849,730	27,142,404	46.36	585,470
2003	13,216,009.40	6,507,193	2,818,634	20,970,183	47.22	444,095
2004	19,868,131.38	9,298,285	4,027,615	31,735,021	48.10	659,772
2005	24,737,106.28	10,981,197	4,756,579	39,770,212	48.97	812,134
2006	19,505,794.97	8,183,539	3,544,755	31,565,676	49.85	633,213
2007	25,113,690.38	9,916,995	4,295,613	40,909,030	50.74	806,248

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -80						
2008	23,037,878.71	8,529,590	3,694,649	37,773,533	51.63	731,620
2009	29,786,706.93	10,286,244	4,455,556	49,160,516	52.53	935,856
2010	20,986,020.87	6,723,921	2,912,512	34,862,326	53.43	652,486
2011	18,897,904.29	5,583,764	2,418,645	31,597,583	54.33	581,586
2012	32,679,219.32	8,832,213	3,825,732	54,996,863	55.24	995,599
2013	37,028,693.79	9,074,622	3,930,734	62,720,915	56.15	1,117,024
2014	15,992,479.76	3,511,949	1,521,224	27,265,240	57.07	477,751
2015	30,712,449.21	5,962,208	2,582,571	52,699,838	57.99	908,775
2016	17,793,204.42	3,000,682	1,299,766	30,728,002	58.91	521,609
2017	24,839,622.01	3,549,185	1,537,353	43,173,967	59.84	721,490
2018	31,228,679.48	3,658,252	1,584,596	54,627,027	60.77	898,914
2019	24,042,412.14	2,190,648	948,894	42,327,448	61.71	685,909
2020	51,477,679.01	3,364,478	1,457,346	91,202,476	62.64	1,455,978
2021	59,022,795.99	2,321,367	1,005,516	105,235,517	63.58	1,655,167
2022	85,936,773.37	1,118,381	484,434	154,201,758	64.53	2,389,613
	1,024,137,859.55	471,855,223	204,387,268	1,639,060,879		36,416,835
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					45.0	3.56

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. -20						
1937	992,853.99	966,639	1,120,282	71,143	11.32	6,285
1938	108,096.95	104,444	121,045	8,671	11.69	742
1939	105,521.11	101,195	117,280	9,345	12.05	776
1940	130,089.10	123,793	143,469	12,638	12.42	1,018
1941	156,644.13	147,873	171,377	16,596	12.80	1,297
1942	125,600.14	117,611	136,305	14,415	13.18	1,094
1943	54,390.96	50,518	58,548	6,721	13.56	496
1944	77,439.14	71,321	82,657	10,270	13.95	736
1945	64,033.76	58,463	67,755	9,086	14.35	633
1946	171,191.23	154,962	179,593	25,836	14.74	1,753
1947	281,839.92	252,810	292,993	45,215	15.15	2,984
1948	395,534.44	351,629	407,519	67,122	15.55	4,317
1949	599,840.96	528,218	612,176	107,633	15.97	6,740
1950	496,073.10	432,774	501,562	93,726	16.38	5,722
1951	839,525.59	725,179	840,443	166,988	16.81	9,934
1952	890,504.53	761,734	882,808	185,797	17.23	10,783
1953	825,277.98	698,849	809,928	180,406	17.66	10,216
1954	668,590.82	560,276	649,329	152,980	18.10	8,452
1955	1,733,779.68	1,437,650	1,666,158	414,378	18.54	22,350
1956	2,104,173.29	1,725,843	2,000,158	524,850	18.99	27,638
1957	2,445,396.40	1,983,207	2,298,429	636,047	19.45	32,702
1958	2,551,208.90	2,046,059	2,371,271	690,180	19.90	34,682
1959	3,552,976.01	2,816,089	3,263,694	999,877	20.37	49,086
1960	6,104,902.22	4,781,384	5,541,365	1,784,518	20.84	85,629
1961	1,536,035.13	1,188,578	1,377,497	465,745	21.31	21,856
1962	6,696,162.43	5,117,181	5,930,535	2,104,860	21.79	96,598
1963	8,018,986.90	6,049,556	7,011,107	2,611,677	22.28	117,221
1964	8,690,314.32	6,470,808	7,499,315	2,929,062	22.77	128,637
1965	10,280,379.23	7,552,008	8,752,367	3,584,088	23.27	154,022
1966	9,019,697.74	6,535,637	7,574,449	3,249,188	23.77	136,693
1967	10,434,891.97	7,454,645	8,639,529	3,882,341	24.28	159,899
1968	12,410,737.00	8,739,591	10,128,712	4,764,172	24.79	192,181
1969	11,286,336.85	7,828,203	9,072,462	4,471,142	25.32	176,585
1970	11,271,422.97	7,700,591	8,924,567	4,601,141	25.84	178,063
1971	7,941,017.29	5,341,128	6,190,077	3,339,144	26.37	126,627
1972	11,813,836.95	7,818,397	9,061,098	5,115,506	26.91	190,097
1973	11,210,723.05	7,295,894	8,455,545	4,997,323	27.46	181,986
1974	10,919,493.60	6,986,336	8,096,784	5,006,608	28.01	178,744
1975	6,279,464.31	3,948,527	4,576,128	2,959,229	28.56	103,614
1976	7,530,805.18	4,651,055	5,390,320	3,646,646	29.12	125,228
1977	7,990,558.00	4,843,908	5,613,826	3,974,844	29.69	133,878

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. -20						
1978	8,642,269.49	5,140,456	5,957,509	4,413,214	30.26	145,843
1979	9,779,072.38	5,703,155	6,609,647	5,125,240	30.84	166,188
1980	10,379,960.87	5,933,144	6,876,192	5,579,761	31.42	177,586
1981	12,154,702.14	6,804,202	7,885,701	6,699,942	32.01	209,308
1982	6,050,703.57	3,314,575	3,841,413	3,419,431	32.61	104,858
1983	12,834,077.34	6,876,499	7,969,489	7,431,404	33.21	223,770
1984	13,311,693.37	6,972,665	8,080,940	7,893,092	33.81	233,454
1985	14,591,806.80	7,462,308	8,648,410	8,861,758	34.43	257,385
1986	16,524,364.35	8,248,963	9,560,100	10,269,137	35.04	293,069
1987	20,812,532.53	10,131,624	11,742,002	13,233,037	35.66	371,089
1988	21,259,550.16	10,081,364	11,683,754	13,827,706	36.29	381,034
1989	23,040,059.51	10,635,384	12,325,833	15,322,238	36.92	415,012
1990	27,739,573.76	12,455,180	14,434,878	18,852,611	37.55	502,067
1991	24,713,472.43	10,780,017	12,493,455	17,162,712	38.19	449,403
1992	26,834,290.64	11,356,379	13,161,427	19,039,722	38.84	490,209
1993	25,129,134.77	10,307,871	11,946,263	18,208,699	39.49	461,096
1994	26,730,294.96	10,617,273	12,304,843	19,771,511	40.14	492,564
1995	23,535,374.29	9,042,385	10,479,633	17,762,816	40.79	435,470
1996	19,791,217.94	7,342,621	8,509,699	15,239,763	41.45	367,666
1997	28,269,415.99	10,109,143	11,715,948	22,207,351	42.12	527,240
1998	30,805,084.10	10,609,271	12,295,569	24,670,532	42.78	576,684
1999	10,552,280.98	3,492,763	4,047,923	8,614,814	43.45	198,270
2000	26,597,686.00	8,447,531	9,790,230	22,126,993	44.12	501,518
2001	20,077,270.64	6,103,410	7,073,521	17,019,204	44.80	379,893
2002	21,452,924.41	6,229,929	7,220,150	18,523,359	45.48	407,286
2003	19,545,119.80	5,410,167	6,270,090	17,184,054	46.16	372,272
2004	26,320,534.16	6,927,459	8,028,549	23,556,092	46.84	502,905
2005	24,541,322.33	6,125,514	7,099,138	22,350,449	47.52	470,338
2006	28,033,670.83	6,610,340	7,661,025	25,979,380	48.21	538,879
2007	31,249,649.20	6,937,422	8,040,096	29,459,483	48.90	602,443
2008	36,996,061.51	7,695,033	8,918,126	35,477,148	49.60	715,265
2009	57,103,307.47	11,089,234	12,851,820	55,672,149	50.29	1,107,022
2010	52,898,295.51	9,532,484	11,047,632	52,430,323	50.99	1,028,247
2011	63,602,026.18	10,570,657	12,250,818	64,071,613	51.69	1,239,536
2012	99,647,292.19	15,146,787	17,554,304	102,022,447	52.40	1,946,993
2013	114,479,552.27	15,798,178	18,309,231	119,066,232	53.10	2,242,302
2014	84,744,882.68	10,491,755	12,159,374	89,534,485	53.81	1,663,900
2015	167,872,511.74	18,365,924	21,285,109	180,161,905	54.53	3,303,904
2016	166,517,395.62	15,819,819	18,334,311	181,486,564	55.25	3,284,825
2017	192,149,840.51	15,488,046	17,949,805	212,630,004	55.97	3,799,000
2018	238,391,541.97	15,782,474	18,291,030	267,778,820	56.69	4,723,564

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. -20						
2019	143,794,945.32	7,419,819	8,599,167	163,954,767	57.42	2,855,360
2020	174,856,271.08	6,468,983	7,497,200	202,330,325	58.15	3,479,455
2021	267,079,707.66	5,929,170	6,871,587	313,624,062	58.89	5,325,591
2022	205,294,037.98	1,519,997	1,761,594	244,591,252	59.63	4,101,815
	2,855,533,126.70	529,847,937	614,064,997	2,812,574,755		54,799,572
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					51.3	1.92

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. -5						
1926	4,690,473.24	4,661,017	4,924,997			
1927	1,225,303.94	1,213,145	1,286,569			
1928	1,782,679.06	1,758,512	1,871,813			
1929	1,875,880.28	1,843,615	1,969,674			
1930	1,554,191.37	1,521,584	1,631,901			
1931	1,068,529.87	1,042,073	1,121,956			
1932	453,389.21	440,449	476,059			
1933	69,611.13	67,352	73,092			
1934	491,923.64	474,026	516,520			
1935	646,768.42	620,615	679,107			
1936	455,122.63	434,870	477,879			
1937	568,215.71	540,544	596,626			
1938	2,505,863.25	2,372,961	2,631,156			
1939	911,556.70	859,124	957,135			
1940	681,666.24	639,307	715,750			
1941	494,013.18	460,965	518,714			
1942	182,900.26	169,743	192,045			
1943	112,607.67	103,923	118,238			
1944	23,238.17	21,319	24,400			
1945	59,546.58	54,288	62,524			
1946	147,097.58	133,242	154,452			
1947	197,140.88	177,329	206,998			
1948	191,960.98	171,432	201,559			
1949	212,770.60	188,557	223,409			
1950	480,517.18	422,403	504,543			
1951	732,456.23	638,436	769,079			
1952	1,250,061.63	1,079,978	1,312,565			
1953	1,449,816.05	1,240,985	1,522,307			
1954	1,512,600.78	1,282,020	1,588,231			
1955	1,556,324.11	1,305,793	1,634,140			
1956	1,069,457.81	887,868	1,122,931			
1957	2,259,299.83	1,855,419	2,372,265			
1958	1,458,633.01	1,184,405	1,531,565			
1959	1,321,438.56	1,060,613	1,387,510			
1960	1,775,407.27	1,408,069	1,863,228	950	18.35	52
1961	3,704,285.10	2,902,617	3,840,890	48,609	19.03	2,554
1962	3,424,540.98	2,649,829	3,506,388	89,380	19.73	4,530
1963	2,809,858.83	2,146,292	2,840,082	110,270	20.44	5,395
1964	2,351,863.23	1,773,070	2,346,216	123,240	21.15	5,827
1965	2,578,748.52	1,917,773	2,537,694	169,992	21.88	7,769
1966	2,701,558.05	1,981,475	2,621,988	214,648	22.61	9,493

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. -5						
1967	2,897,057.72	2,094,447	2,771,478	270,433	23.36	11,577
1968	4,099,291.82	2,920,567	3,864,642	439,614	24.11	18,234
1969	3,938,373.14	2,763,491	3,656,791	478,501	24.88	19,232
1970	3,361,924.59	2,322,754	3,073,586	456,435	25.65	17,795
1971	2,800,300.91	1,903,766	2,519,160	421,156	26.44	15,929
1972	3,036,433.09	2,030,695	2,687,119	501,136	27.23	18,404
1973	3,596,432.96	2,364,426	3,128,728	647,527	28.04	23,093
1974	3,114,025.98	2,011,961	2,662,329	607,398	28.85	21,054
1975	2,215,549.03	1,405,729	1,860,132	466,194	29.68	15,707
1976	2,045,099.21	1,273,810	1,685,570	461,784	30.51	15,135
1977	2,261,464.13	1,381,981	1,828,707	545,830	31.35	17,411
1978	1,831,840.87	1,097,376	1,452,104	471,329	32.21	14,633
1979	3,911,702.90	2,296,262	3,038,530	1,068,758	33.07	32,318
1980	1,473,849.47	847,233	1,121,102	426,440	33.94	12,565
1981	4,447,506.68	2,502,450	3,311,369	1,358,513	34.81	39,027
1982	1,811,018.14	996,422	1,318,516	583,053	35.70	16,332
1983	2,206,449.25	1,186,488	1,570,021	746,751	36.59	20,409
1984	2,855,271.05	1,499,407	1,984,091	1,013,944	37.49	27,046
1985	4,469,253.37	2,290,045	3,030,304	1,662,412	38.40	43,292
1986	4,958,315.69	2,476,760	3,277,374	1,928,857	39.32	49,055
1987	18,411,375.46	8,959,776	11,856,030	7,475,914	40.24	185,783
1988	12,679,487.68	6,007,034	7,948,812	5,364,650	41.16	130,336
1989	14,934,793.68	6,879,018	9,102,665	6,578,868	42.10	156,268
1990	16,948,541.45	7,583,396	10,034,734	7,761,235	43.04	180,326
1991	12,743,859.73	5,534,403	7,323,403	6,057,650	43.98	137,736
1992	12,795,464.56	5,386,590	7,127,809	6,307,429	44.93	140,383
1993	13,459,068.56	5,487,040	7,260,730	6,871,292	45.88	149,767
1994	10,326,741.49	4,071,251	5,387,286	5,455,793	46.84	116,477
1995	14,003,961.02	5,332,757	7,056,574	7,647,585	47.80	159,991
1996	6,314,260.94	2,318,701	3,068,223	3,561,751	48.77	73,032
1997	8,017,442.90	2,836,383	3,753,246	4,665,069	49.73	93,808
1998	24,673,592.25	8,390,588	11,102,851	14,804,421	50.71	291,943
1999	16,498,048.05	5,386,225	7,127,326	10,195,624	51.68	197,284
2000	16,433,355.66	5,139,754	6,801,183	10,453,840	52.66	198,516
2001	4,294,730.75	1,284,296	1,699,446	2,810,021	53.64	52,387
2002	14,000,327.45	3,994,524	5,285,757	9,414,587	54.62	172,365
2003	17,813,184.41	4,838,123	6,402,050	12,301,794	55.60	221,255
2004	7,643,382.82	1,970,032	2,606,846	5,418,706	56.59	95,754
2005	10,362,165.01	2,527,161	3,344,068	7,536,205	57.58	130,882
2006	11,404,378.04	2,623,275	3,471,250	8,503,347	58.57	145,183
2007	13,581,401.58	2,935,803	3,884,803	10,375,669	59.56	174,205

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. -5						
2008	17,669,985.42	3,574,700	4,730,224	13,823,261	60.55	228,295
2009	31,495,134.73	5,935,053	7,853,563	25,216,328	61.54	409,755
2010	12,544,338.59	2,190,035	2,897,965	10,273,591	62.53	164,299
2011	12,777,305.54	2,051,735	2,714,960	10,701,211	63.53	168,443
2012	410,755.54	60,265	79,746	351,547	64.52	5,449
2013	13,440,868.57	1,783,872	2,360,510	11,752,402	65.52	179,371
2014	30,094.07	3,573	4,728	26,871	66.52	404
2015	3,497,248.32	366,734	485,281	3,186,830	67.51	47,205
2016	1,261,608.51	114,625	151,678	1,173,011	68.51	17,122
2017	3,280,653.03	252,151	333,659	3,111,027	69.51	44,757
2018	5,187,196.33	326,085	431,492	5,015,064	70.51	71,126
2019	2,935,887.07	143,869	190,375	2,892,306	71.50	40,452
2020	2,021,827.58	70,757	93,629	2,029,290	72.50	27,990
2021	8,832,231.15	185,477	245,433	9,028,410	73.50	122,836
2022	2,702,474.63	18,927	25,045	2,812,554	74.50	37,752
	509,797,650.33	199,937,095	259,019,228	276,268,305		5,252,805
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.6						1.03

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. -20						
1938	2,034.34	2,170	2,327	114	6.44	18
1939	11,681.52	12,391	13,288	730	6.73	108
1940	60,583.22	63,901	68,528	4,172	7.02	594
1941	73,868.79	77,455	83,064	5,579	7.32	762
1942	47,499.28	49,511	53,096	3,903	7.62	512
1943	20,452.21	21,191	22,725	1,818	7.92	230
1944	20,826.85	21,446	22,999	1,993	8.23	242
1945	41,013.35	41,969	45,008	4,208	8.54	493
1946	60,344.13	61,363	65,806	6,607	8.85	747
1947	8,582.30	8,671	9,299	1,000	9.17	109
1948	236,323.14	237,139	254,311	29,277	9.50	3,082
1949	248,790.29	247,950	265,905	32,643	9.83	3,321
1950	221,444.80	219,140	235,009	30,725	10.17	3,021
1951	410,421.03	403,175	432,370	60,135	10.52	5,716
1952	471,298.00	459,566	492,844	72,714	10.87	6,689
1955	1,253,629.54	1,193,631	1,280,065	224,290	11.98	18,722
1956	1,162,772.15	1,097,982	1,177,490	217,837	12.36	17,624
1957	1,213,293.95	1,135,643	1,217,878	238,075	12.76	18,658
1958	1,392,203.16	1,291,291	1,384,797	285,847	13.17	21,704
1959	1,387,990.43	1,275,608	1,367,978	297,611	13.58	21,915
1960	2,106,658.29	1,917,354	2,056,195	471,795	14.01	33,676
1962	343,938.28	306,771	328,985	83,741	14.89	5,624
1963	2,446,666.77	2,159,487	2,315,862	620,138	15.34	40,426
1964	2,829,429.84	2,469,787	2,648,631	746,685	15.81	47,229
1965	2,216,273.79	1,913,025	2,051,553	607,976	16.28	37,345
1966	3,221,123.24	2,747,721	2,946,691	918,657	16.77	54,780
1967	3,919,546.75	3,302,955	3,542,131	1,161,325	17.27	67,245
1968	4,690,110.58	3,903,785	4,186,469	1,441,664	17.77	81,129
1969	6,044,197.01	4,965,864	5,325,456	1,927,580	18.29	105,390
1970	5,927,857.80	4,805,264	5,153,227	1,960,202	18.82	104,155
1972	6,187,412.70	4,877,414	5,230,601	2,194,294	19.90	110,266
1973	6,292,575.76	4,887,368	5,241,276	2,309,815	20.46	112,894
1974	5,025,984.73	3,844,336	4,122,715	1,908,467	21.03	90,750
1975	5,900,133.70	4,443,438	4,765,200	2,314,960	21.60	107,174
1976	5,488,831.07	4,066,631	4,361,107	2,225,490	22.19	100,292
1977	4,006,734.39	2,918,842	3,130,204	1,677,877	22.79	73,623
1978	5,684,185.20	4,070,240	4,364,978	2,456,044	23.39	105,004
1979	7,422,396.78	5,219,697	5,597,670	3,309,206	24.01	137,826
1980	6,243,397.08	4,310,491	4,622,626	2,869,450	24.63	116,502
1981	6,922,933.73	4,688,017	5,027,490	3,280,030	25.27	129,799
1982	29,302.39	19,455	20,864	14,299	25.91	552

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. -20						
1983	7,338,820.60	4,773,785	5,119,468	3,687,117	26.56	138,822
1984	9,847,838.69	6,271,379	6,725,507	5,091,899	27.22	187,065
1985	11,611,143.25	7,233,371	7,757,160	6,176,212	27.89	221,449
1986	12,532,340.27	7,630,842	8,183,413	6,855,395	28.57	239,951
1987	22,030,541.98	13,104,383	14,053,308	12,383,342	29.25	423,362
1988	17,396,280.32	10,095,827	10,826,894	10,048,642	29.95	335,514
1989	23,596,058.98	13,352,066	14,318,927	13,996,344	30.65	456,651
1990	12,237,348.87	6,744,884	7,233,300	7,451,519	31.36	237,612
1991	24,864,815.34	13,334,503	14,300,092	15,537,686	32.08	484,342
1992	22,615,417.92	11,791,136	12,644,965	14,493,537	32.80	441,876
1993	29,282,996.96	14,825,396	15,898,945	19,240,651	33.53	573,834
1994	25,327,295.28	12,434,892	13,335,338	17,057,416	34.27	497,736
1995	22,199,233.94	10,554,670	11,318,963	15,320,118	35.02	437,468
1996	25,396,650.14	11,675,348	12,520,793	17,955,187	35.78	501,822
1997	31,070,504.81	13,795,304	14,794,261	22,490,345	36.54	615,499
1998	45,548,028.07	19,497,471	20,909,338	33,748,296	37.31	904,538
1999	20,233,417.49	8,339,001	8,942,852	15,337,249	38.08	402,764
2000	32,013,452.91	12,677,327	13,595,328	24,820,815	38.86	638,724
2001	33,185,048.18	12,598,903	13,511,225	26,310,833	39.65	663,577
2002	33,438,545.20	12,141,803	13,021,025	27,105,229	40.45	670,092
2003	35,150,408.30	12,181,304	13,063,386	29,117,104	41.25	705,869
2004	31,113,251.12	10,261,026	11,004,056	26,331,845	42.06	626,054
2005	35,615,055.98	11,148,652	11,955,957	30,782,110	42.87	718,034
2006	40,988,021.37	12,135,078	13,013,813	36,171,813	43.69	827,920
2007	44,455,836.71	12,398,377	13,296,178	40,050,826	44.52	899,614
2008	45,039,331.29	11,787,694	12,641,274	41,405,924	45.35	913,030
2009	193,856,939.36	47,367,780	50,797,814	181,830,513	46.19	3,936,577
2010	34,640,436.31	7,862,271	8,431,600	33,136,924	47.03	704,591
2011	45,729,315.49	9,574,621	10,267,946	44,607,233	47.88	931,646
2012	55,276,124.55	10,601,740	11,369,442	54,961,907	48.73	1,127,886
2013	52,950,507.28	9,213,388	9,880,556	53,660,053	49.59	1,082,074
2014	15,562,973.30	2,427,824	2,603,630	16,071,938	50.46	318,508
2015	34,496,543.04	4,767,560	5,112,792	36,283,060	51.32	706,996
2016	30,759,094.96	3,691,091	3,958,373	32,952,541	52.20	631,275
2017	36,010,189.95	3,665,693	3,931,136	39,281,092	53.08	740,036
2018	39,633,833.44	3,313,071	3,552,980	44,007,620	53.96	815,560
2019	35,040,487.19	2,283,659	2,449,025	39,599,560	54.85	721,961

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. -20						
2020	19,642,322.69	914,311	980,519	22,590,268	55.75	405,207
2021	41,135,225.15	1,157,545	1,241,366	48,120,904	56.64	849,592
2022	31,197,223.56	290,509	311,546	37,125,122	57.55	645,093
	1,461,353,642.60	479,674,620	514,409,209	1,239,215,162		29,166,169
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					42.5	2.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. -30						
1930	341,473.41	423,415	250,664	193,251	2.54	76,083
1931	281,658.86	347,384	205,653	160,504	2.82	56,916
1932	278,501.73	341,647	202,257	159,795	3.10	51,547
1933	366,909.87	447,582	264,971	212,012	3.39	62,540
1934	325,651.07	395,020	233,854	189,492	3.68	51,492
1935	256,489.33	309,429	183,183	150,253	3.96	37,943
1936	1,186,501.10	1,423,266	842,580	699,871	4.25	164,676
1937	1,486,930.11	1,773,439	1,049,884	883,125	4.54	194,521
1938	1,528,894.82	1,813,015	1,073,313	914,250	4.83	189,286
1939	950,746.11	1,120,914	663,586	572,384	5.12	111,794
1940	30,980.01	36,313	21,497	18,777	5.41	3,471
1941	78,278.34	91,215	54,000	47,762	5.70	8,379
1942	624,739.36	723,709	428,439	383,722	5.99	64,060
1943	72,460.47	83,426	49,389	44,810	6.29	7,124
1944	198,961.38	227,705	134,802	123,848	6.58	18,822
1945	136,400.10	155,139	91,843	85,477	6.88	12,424
1946	130,615.87	147,633	87,399	82,402	7.18	11,477
1947	83,854.70	94,186	55,759	53,252	7.48	7,119
1948	74,370.81	83,006	49,140	47,542	7.78	6,111
1949	330,211.17	366,133	216,752	212,523	8.09	26,270
1950	316,302.50	348,318	206,206	204,987	8.41	24,374
1951	185,338.83	202,696	119,997	120,943	8.73	13,854
1952	237,896.82	258,320	152,927	156,339	9.06	17,256
1953	942,347.23	1,015,898	601,416	623,635	9.39	66,415
1954	1,006,513.61	1,076,987	637,581	670,887	9.73	68,950
1955	703,544.40	746,988	442,220	472,388	10.08	46,864
1956	6,808,857.36	7,172,913	4,246,396	4,605,119	10.43	441,526
1957	3,986,139.16	4,164,447	2,465,371	2,716,610	10.80	251,538
1958	4,984,094.79	5,163,437	3,056,777	3,422,546	11.17	306,405
1959	3,074,713.70	3,157,731	1,869,391	2,127,737	11.55	184,220
1960	6,282,240.86	6,392,488	3,784,381	4,382,532	11.95	366,739
1961	6,399,005.04	6,450,741	3,818,867	4,499,840	12.35	364,360
1962	8,077,068.13	8,064,145	4,774,009	5,726,180	12.76	448,760
1963	13,085,240.92	12,934,342	7,657,187	9,353,626	13.18	709,683
1964	11,475,604.26	11,223,921	6,644,610	8,273,676	13.62	607,465
1965	6,031,179.30	5,836,179	3,455,043	4,385,490	14.06	311,913
1966	5,670,952.11	5,427,294	3,212,982	4,159,256	14.51	286,648
1967	8,789,927.86	8,314,674	4,922,323	6,504,583	14.98	434,218
1968	6,081,285.85	5,684,889	3,365,479	4,540,193	15.45	293,864
1969	5,967,277.06	5,509,193	3,261,466	4,495,994	15.94	282,057
1970	5,795,089.74	5,281,743	3,126,815	4,406,802	16.44	268,054

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 55-R2
NET SALVAGE PERCENT.. -30

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1971	13,439,785.54	12,087,286	7,155,726	10,315,995	16.95	608,613
1972	14,694,698.87	13,035,197	7,716,894	11,386,215	17.47	651,758
1973	14,459,980.99	12,649,346	7,488,468	11,309,507	17.99	628,655
1974	12,588,711.01	10,848,737	6,422,500	9,942,824	18.54	536,290
1975	11,166,160.56	9,477,647	5,610,808	8,905,201	19.09	466,485
1976	7,866,817.13	6,573,111	3,891,310	6,335,552	19.65	322,420
1977	7,323,795.33	6,020,658	3,564,256	5,956,678	20.22	294,593
1978	15,431,596.89	12,474,378	7,384,886	12,676,190	20.80	609,432
1979	13,819,364.99	10,975,105	6,497,310	11,467,864	21.40	535,881
1980	17,463,383.58	13,621,439	8,063,951	14,638,448	22.00	665,384
1981	15,697,378.55	12,017,646	7,114,499	13,292,093	22.61	587,886
1982	9,718,086.24	7,297,622	4,320,224	8,313,288	23.23	357,869
1983	18,193,481.97	13,386,764	7,925,023	15,726,504	23.87	658,840
1984	35,514,470.23	25,594,142	15,151,844	31,016,967	24.51	1,265,482
1985	31,381,429.73	22,133,793	13,103,302	27,692,557	25.16	1,100,658
1986	41,765,252.68	28,806,121	17,053,350	37,241,478	25.82	1,442,350
1987	40,772,166.76	27,475,058	16,265,355	36,738,462	26.49	1,386,880
1988	35,452,654.12	23,320,756	13,805,990	32,282,460	27.17	1,188,166
1989	34,866,754.10	22,375,112	13,246,164	32,080,616	27.85	1,151,907
1990	11,785,430.67	7,368,051	4,361,918	10,959,142	28.55	383,858
1991	9,878,005.43	6,012,090	3,559,184	9,282,223	29.25	317,341
1992	15,988,683.24	9,462,918	5,602,089	15,183,199	29.96	506,782
1993	18,689,662.51	10,743,453	6,360,171	17,936,390	30.68	584,628
1994	10,787,453.15	6,014,900	3,560,847	10,462,842	31.41	333,105
1995	15,422,186.81	8,329,292	4,930,977	15,117,866	32.15	470,229
1996	24,497,715.67	12,802,506	7,579,140	24,267,890	32.89	737,850
1997	22,251,926.79	11,234,286	6,650,746	22,276,759	33.64	662,210
1998	21,429,825.03	10,434,503	6,177,271	21,681,502	34.40	630,276
1999	11,660,337.08	5,465,375	3,235,526	11,922,912	35.17	339,008
2000	13,822,116.52	6,227,071	3,686,453	14,282,298	35.94	397,393
2001	19,620,763.70	8,477,504	5,018,719	20,488,274	36.72	557,960
2002	30,572,529.98	12,638,684	7,482,156	32,262,133	37.51	860,094
2003	13,228,598.00	5,218,483	3,089,365	14,107,812	38.31	368,254
2004	18,908,289.73	7,101,632	4,204,197	20,376,580	39.11	521,007
2005	19,692,027.31	7,018,908	4,155,224	21,444,412	39.92	537,185
2006	20,629,333.37	6,957,965	4,119,146	22,698,987	40.73	557,304
2007	15,617,264.31	4,964,963	2,939,280	17,363,164	41.55	417,886
2008	16,455,690.81	4,908,486	2,905,845	18,486,553	42.38	436,209
2009	40,449,980.61	11,272,115	6,673,142	45,911,833	43.21	1,062,528
2010	14,567,995.19	3,770,445	2,232,120	16,706,274	44.05	379,257
2011	19,977,802.16	4,774,015	2,826,238	23,144,905	44.89	515,592

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. -30						
2012	43,384,414.55	9,485,308	5,615,344	50,784,395	45.75	1,110,041
2013	45,658,175.88	9,065,385	5,366,748	53,988,881	46.60	1,158,560
2014	39,184,004.61	6,983,256	4,134,118	46,805,088	47.46	986,201
2015	53,083,898.96	8,368,730	4,954,325	64,054,744	48.33	1,325,362
2016	53,665,422.88	7,356,724	4,355,213	65,409,837	49.20	1,329,468
2017	57,245,843.08	6,656,833	3,940,874	70,478,722	50.08	1,407,323
2018	70,223,950.93	6,688,902	3,959,859	87,331,277	50.97	1,713,386
2019	61,837,475.74	4,603,862	2,725,506	77,663,212	51.85	1,497,844
2020	75,360,533.40	4,007,899	2,372,694	95,595,999	52.75	1,812,246
2021	79,123,886.65	2,525,239	1,494,953	101,366,100	53.65	1,889,396
2022	91,161,268.42	969,409	573,894	117,935,755	54.55	2,161,975
	1,582,143,710.59	642,910,030	380,605,551	1,676,181,273		49,384,525
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					33.9	3.12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -80						
1926	33,829.15	60,368	41,552	19,340	0.56	19,340
1927	23,067.93	41,030	28,241	13,281	0.77	13,281
1928	24,000.17	42,562	29,296	13,904	0.96	13,904
1929	30,344.58	53,637	36,919	17,701	1.17	15,129
1930	29,607.40	52,162	35,904	17,389	1.38	12,601
1931	21,033.83	36,935	25,423	12,438	1.59	7,823
1932	15,552.04	27,210	18,729	9,265	1.82	5,091
1933	11,232.12	19,583	13,479	6,739	2.04	3,303
1934	20,670.69	35,902	24,712	12,495	2.28	5,480
1935	48,695.94	84,268	58,003	29,650	2.51	11,813
1936	46,335.62	79,863	54,971	28,433	2.76	10,302
1937	2,615.42	4,490	3,091	1,617	3.01	537
1938	103,123.58	176,313	121,358	64,264	3.26	19,713
1939	73,360.06	124,898	85,969	46,079	3.52	13,091
1940	86,286.54	146,284	100,689	54,627	3.78	14,452
1941	95,988.75	162,041	111,535	61,245	4.04	15,160
1942	56,263.26	94,575	65,097	36,177	4.30	8,413
1943	29,835.46	49,928	34,366	19,338	4.57	4,232
1944	23,992.12	39,963	27,507	15,679	4.85	3,233
1945	44,973.47	74,576	51,332	29,620	5.12	5,785
1946	139,788.66	230,715	158,804	92,816	5.40	17,188
1947	241,082.06	395,960	272,544	161,404	5.69	28,366
1948	313,867.56	512,900	353,035	211,927	5.99	35,380
1949	373,884.23	607,765	418,332	254,660	6.30	40,422
1950	479,130.48	774,734	533,259	329,176	6.61	49,800
1951	598,635.23	962,494	662,497	415,046	6.94	59,805
1952	553,825.93	885,086	609,216	387,671	7.29	53,178
1953	587,338.42	932,786	642,048	415,161	7.65	54,269
1954	28,480.73	44,932	30,927	20,338	8.03	2,533
1955	162,371.29	254,408	175,112	117,156	8.42	13,914
1956	860,026.34	1,337,513	920,627	627,420	8.84	70,975
1957	788,449.84	1,216,589	837,393	581,817	9.28	62,696
1958	867,164.82	1,326,762	913,227	647,670	9.75	66,428
1959	1,050,793.22	1,593,452	1,096,793	794,635	10.24	77,601
1960	1,120,002.19	1,682,597	1,158,153	857,851	10.75	79,800
1961	1,313,312.33	1,952,987	1,344,265	1,019,697	11.30	90,239
1962	1,542,138.90	2,269,368	1,562,034	1,213,816	11.86	102,345
1963	1,657,839.69	2,412,535	1,660,578	1,323,533	12.45	106,308
1964	1,607,821.31	2,312,600	1,591,791	1,302,287	13.06	99,716
1965	1,706,871.37	2,425,266	1,669,341	1,403,027	13.69	102,486
1966	1,847,978.10	2,592,499	1,784,449	1,541,912	14.34	107,525

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -80						
1967	1,898,702.79	2,628,970	1,809,553	1,608,112	15.00	107,207
1968	2,125,550.29	2,903,621	1,998,599	1,827,392	15.67	116,617
1969	2,642,940.52	3,559,930	2,450,344	2,306,949	16.36	141,012
1970	2,638,797.46	3,503,906	2,411,782	2,338,053	17.05	137,129
1971	2,716,969.93	3,554,302	2,446,470	2,444,076	17.76	137,617
1972	2,706,616.23	3,486,777	2,399,992	2,471,917	18.48	133,762
1973	2,987,490.84	3,789,082	2,608,072	2,769,412	19.20	144,240
1974	3,283,090.29	4,096,686	2,819,800	3,089,763	19.94	154,953
1975	3,456,303.54	4,241,030	2,919,154	3,302,192	20.69	159,603
1976	3,485,922.17	4,203,081	2,893,033	3,381,627	21.46	157,578
1977	3,437,431.45	4,071,294	2,802,323	3,385,054	22.23	152,274
1978	4,086,856.96	4,751,094	3,270,237	4,086,106	23.02	177,502
1979	4,981,923.79	5,682,592	3,911,399	5,056,064	23.81	212,350
1980	4,089,293.62	4,572,705	3,147,450	4,213,279	24.62	171,132
1981	4,687,929.40	5,135,702	3,534,968	4,903,305	25.44	192,740
1982	4,838,762.40	5,189,718	3,572,148	5,137,624	26.27	195,570
1983	5,904,182.84	6,193,405	4,262,998	6,364,531	27.12	234,680
1984	7,293,090.29	7,478,641	5,147,642	7,979,921	27.97	285,303
1985	8,769,631.85	8,783,909	6,046,074	9,739,263	28.83	337,817
1986	9,321,471.65	9,112,149	6,272,006	10,506,643	29.70	353,759
1987	8,483,717.49	8,086,442	5,565,999	9,704,692	30.58	317,354
1988	9,581,235.52	8,896,465	6,123,548	11,122,676	31.47	353,437
1989	9,204,142.23	8,316,863	5,724,601	10,842,855	32.37	334,966
1990	8,941,099.62	7,853,862	5,405,911	10,688,068	33.28	321,156
1991	8,406,704.68	7,170,331	4,935,428	10,196,640	34.20	298,147
1992	9,277,733.28	7,676,786	5,284,028	11,415,892	35.12	325,054
1993	11,966,044.68	9,592,987	6,602,973	14,935,907	36.05	414,311
1994	13,640,674.15	10,580,471	7,282,670	17,270,543	36.99	466,898
1995	14,091,181.68	10,563,144	7,270,744	18,093,383	37.93	477,020
1996	15,455,722.71	11,179,588	7,695,050	20,125,251	38.88	517,625
1997	12,572,156.23	8,762,969	6,031,661	16,598,220	39.83	416,727
1998	14,936,159.64	10,013,620	6,892,500	19,992,587	40.79	490,135
1999	12,258,017.98	7,892,227	5,432,319	16,632,113	41.75	398,374
2000	14,922,657.70	9,207,071	6,337,342	20,523,442	42.72	480,418
2001	14,044,465.28	8,288,060	5,704,775	19,575,263	43.69	448,049
2002	12,845,715.65	7,235,426	4,980,234	18,142,054	44.66	406,226
2003	20,407,111.80	10,940,865	7,530,734	29,202,067	45.64	639,835
2004	23,559,990.33	11,991,705	8,254,041	34,153,942	46.62	732,603
2005	18,311,928.10	8,823,456	6,073,295	26,888,176	47.60	564,878
2006	19,925,647.92	9,060,511	6,236,463	29,629,703	48.58	609,916
2007	19,561,942.25	8,358,505	5,753,264	29,458,232	49.57	594,275

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -80						
2008	18,059,100.12	7,221,292	4,970,506	27,535,874	50.56	544,618
2009	16,264,712.66	6,057,890	4,169,721	25,106,762	51.55	487,037
2010	18,449,034.02	6,365,692	4,381,585	28,826,676	52.54	548,662
2011	14,799,868.26	4,700,853	3,235,656	23,404,107	53.53	437,215
2012	9,307,111.70	2,698,541	1,857,440	14,895,361	54.53	273,159
2013	940,669.03	246,954	169,982	1,523,222	55.52	27,436
2014	3,077,368.46	722,652	497,410	5,041,853	56.52	89,205
2015	3,728,103.02	773,261	532,245	6,178,340	57.51	107,431
2016	6,300,410.65	1,132,373	779,426	10,561,313	58.51	180,504
2017	4,931,628.13	749,746	516,060	8,360,871	59.51	140,495
2018	17,916,432.36	2,227,801	1,533,423	30,716,155	60.51	507,621
2019	4,514,150.93	437,557	301,176	7,824,296	61.50	127,224
2020	10,106,114.15	699,626	481,561	17,709,444	62.50	283,351
2021	2,250,329.07	93,488	64,349	3,986,243	63.50	62,775
2022	8,064,424.92	111,628	76,835	14,439,129	64.50	223,862
	535,118,075.54	349,799,838	240,771,597	722,440,939		18,874,501
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.3	3.53

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. -20						
1950	361,966.84	394,399	243,899	190,461	1.84	103,511
1951	114,675.25	124,124	76,759	60,851	1.96	31,046
1952	252,559.64	271,552	167,930	135,142	2.08	64,972
1953	471,747.78	503,827	311,571	254,526	2.20	115,694
1954	78,486.19	83,211	51,458	42,725	2.33	18,337
1955	149,296.81	157,210	97,220	81,936	2.45	33,443
1956	204,757.23	214,012	132,347	113,362	2.58	43,939
1957	300,219.43	311,448	192,602	167,661	2.71	61,868
1958	332,194.37	342,027	211,512	187,121	2.84	65,888
1959	364,754.07	372,706	230,484	207,221	2.97	69,771
1960	486,258.07	492,774	304,735	278,775	3.11	89,638
1961	521,332.56	524,252	324,202	301,397	3.24	93,024
1962	597,947.93	596,274	368,741	348,797	3.38	103,194
1963	576,823.99	570,710	352,932	339,257	3.51	96,654
1964	544,911.98	535,213	330,980	322,914	3.63	88,957
1965	613,539.00	597,832	369,704	366,543	3.76	97,485
1966	667,450.51	645,959	399,466	401,475	3.87	103,740
1967	557,772.44	536,131	331,548	337,779	3.98	84,869
1968	534,478.19	510,213	315,520	325,854	4.09	79,671
1969	515,437.03	488,944	302,367	316,157	4.19	75,455
1970	497,783.51	468,912	289,979	307,361	4.30	71,479
1971	1,044,159.54	977,333	604,391	648,600	4.40	147,409
1972	1,132,631.08	1,053,347	651,398	707,759	4.50	157,280
1973	1,233,442.69	1,138,961	704,343	775,788	4.61	168,284
1974	881,867.91	808,496	499,980	558,261	4.72	118,276
1975	681,041.57	619,884	383,341	433,909	4.83	89,836
1976	630,707.41	569,529	352,201	404,648	4.95	81,747
1977	640,710.12	573,948	354,934	413,918	5.07	81,641
1978	2,208,616.18	1,961,251	1,212,853	1,437,486	5.20	276,440
1979	1,776,253.55	1,562,393	966,196	1,165,308	5.34	218,222
1980	849,101.23	739,737	457,459	561,462	5.48	102,457
1981	911,579.46	785,964	486,046	607,849	5.63	107,966
1982	1,585,088.26	1,352,397	836,333	1,065,773	5.78	184,390
1983	1,856,191.86	1,565,883	968,355	1,259,075	5.94	211,965
1984	2,364,403.33	1,970,494	1,218,569	1,618,715	6.11	264,929
1985	2,304,108.23	1,895,359	1,172,105	1,592,825	6.29	253,231
1986	2,727,472.71	2,214,162	1,369,255	1,903,712	6.47	294,237
1987	3,415,528.35	2,733,789	1,690,597	2,408,037	6.66	361,567
1988	3,681,540.27	2,904,735	1,796,311	2,621,537	6.85	382,706
1989	3,703,120.60	2,877,325	1,779,361	2,664,384	7.05	377,927
1990	3,335,892.73	2,549,956	1,576,913	2,426,158	7.26	334,182

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. -20						
1991	3,309,241.98	2,487,888	1,538,530	2,432,560	7.47	325,644
1992	3,954,930.91	2,921,112	1,806,439	2,939,478	7.69	382,247
1993	3,855,242.27	2,794,280	1,728,005	2,898,286	7.92	365,945
1994	3,151,852.88	2,240,967	1,385,832	2,396,391	8.15	294,036
1995	3,585,615.46	2,497,740	1,544,622	2,758,117	8.39	328,739
1996	3,253,035.73	2,217,269	1,371,177	2,532,466	8.64	293,109
1997	3,094,865.58	2,063,037	1,275,799	2,438,040	8.89	274,245
1998	3,528,466.19	2,297,031	1,420,502	2,813,657	9.15	307,503
1999	4,970,652.48	3,155,370	1,951,306	4,013,477	9.42	426,059
2000	4,289,940.46	2,653,757	1,641,105	3,506,824	9.69	361,901
2001	4,020,771.19	2,417,288	1,494,870	3,330,055	9.98	333,673
2002	4,314,990.54	2,519,091	1,557,826	3,620,163	10.27	352,499
2003	4,083,667.78	2,310,539	1,428,856	3,471,545	10.57	328,434
2004	4,717,710.25	2,581,531	1,596,439	4,064,813	10.88	373,604
2005	4,937,153.80	2,609,779	1,613,908	4,310,677	11.19	385,226
2006	6,010,670.26	3,058,229	1,891,233	5,321,571	11.52	461,942
2007	7,102,179.99	3,472,966	2,147,710	6,374,906	11.85	537,967
2008	8,012,236.48	3,749,727	2,318,861	7,295,823	12.20	598,018
2009	5,601,923.62	2,504,060	1,548,531	5,173,777	12.55	412,253
2010	6,477,907.58	2,755,702	1,704,148	6,069,341	12.91	470,127
2011	8,633,474.47	3,475,837	2,149,485	8,210,684	13.29	617,809
2012	12,521,036.77	4,747,977	2,936,187	12,089,057	13.68	883,703
2013	12,530,515.74	4,443,321	2,747,785	12,288,834	14.09	872,167
2014	10,603,278.03	3,479,996	2,152,057	10,571,877	14.53	727,590
2015	20,927,128.87	6,278,139	3,882,451	21,230,104	15.00	1,415,340
2016	14,328,314.44	3,860,048	2,387,085	14,806,892	15.51	954,667
2017	21,223,133.65	5,004,415	3,094,770	22,372,990	16.07	1,392,221
2018	7,876,473.18	1,573,719	973,200	8,478,568	16.67	508,612
2019	12,647,907.93	2,041,372	1,262,401	13,915,089	17.31	803,876
2020	10,657,010.95	1,278,841	790,846	11,997,567	18.00	666,532
2021	22,074,179.25	1,655,563	1,023,813	25,465,202	18.75	1,358,144
2022	73,418,062.06	1,938,237	1,198,622	86,903,053	19.56	4,442,896
	365,421,420.67	132,681,501	82,051,298	356,454,407		28,064,055

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7 7.68

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. -25						
1953	167,143.04	196,393	151,601	57,328	2.28	25,144
1954	17,412.70	20,288	15,661	6,105	2.58	2,366
1955	35,699.80	41,243	31,837	12,788	2.88	4,440
1956	47,076.05	53,921	41,623	17,222	3.18	5,416
1957	70,185.49	79,720	61,538	26,194	3.47	7,549
1958	76,006.39	85,582	66,063	28,945	3.77	7,678
1959	83,507.43	93,177	71,926	32,458	4.08	7,955
1960	114,528.54	126,660	97,772	45,389	4.38	10,363
1961	182,670.92	200,098	154,461	73,878	4.70	15,719
1962	223,609.81	242,661	187,317	92,195	5.01	18,402
1963	203,368.74	218,487	168,656	85,555	5.34	16,022
1964	204,020.98	216,974	167,488	87,538	5.67	15,439
1965	223,877.47	235,662	181,914	97,933	6.00	16,322
1966	245,002.78	255,158	196,964	109,289	6.34	17,238
1967	204,841.34	210,974	162,857	93,195	6.69	13,930
1968	183,908.57	187,235	144,532	85,354	7.05	12,107
1969	184,145.52	185,296	143,035	87,147	7.41	11,761
1970	184,542.93	183,450	141,610	89,069	7.78	11,448
1971	348,796.05	342,487	264,375	171,620	8.15	21,058
1972	367,441.66	356,203	274,963	184,339	8.53	21,611
1973	403,985.03	386,442	298,305	206,676	8.92	23,170
1974	294,808.15	278,129	214,695	153,815	9.32	16,504
1975	221,475.94	206,031	159,041	117,804	9.72	12,120
1976	202,436.84	185,589	143,261	109,785	10.13	10,838
1977	343,076.50	309,785	239,132	189,714	10.55	17,982
1978	1,127,295.66	1,001,954	773,436	635,684	10.98	57,895
1979	877,776.35	767,769	592,662	504,558	11.41	44,221
1980	408,229.22	351,021	270,963	239,324	11.86	20,179
1981	378,051.23	319,477	246,613	225,951	12.31	18,355
1982	2,188,448.75	1,816,276	1,402,034	1,333,527	12.77	104,427
1983	2,468,594.61	2,010,609	1,552,045	1,533,698	13.24	115,838
1984	3,030,631.93	2,421,513	1,869,233	1,919,057	13.71	139,975
1985	3,035,712.53	2,376,659	1,834,609	1,960,032	14.20	138,030
1986	3,883,863.39	2,978,049	2,298,838	2,555,991	14.69	173,995
1987	4,454,462.30	3,340,847	2,578,892	2,989,186	15.20	196,657
1988	4,472,063.36	3,279,029	2,531,173	3,058,906	15.71	194,711
1989	4,206,746.80	3,012,504	2,325,435	2,932,998	16.23	180,715
1990	5,975,217.54	4,172,793	3,221,094	4,247,928	16.77	253,305
1991	6,428,704.33	4,375,296	3,377,412	4,658,468	17.31	269,120
1992	7,161,759.65	4,744,666	3,662,539	5,289,661	17.86	296,174
1993	7,155,081.78	4,608,409	3,557,358	5,386,494	18.42	292,426

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. -25						
1994	5,520,948.74	3,454,251	2,666,432	4,234,754	18.98	223,117
1995	6,654,839.23	4,036,659	3,116,009	5,202,540	19.56	265,979
1996	5,567,760.79	3,269,250	2,523,624	4,436,077	20.15	220,153
1997	5,028,567.29	2,855,032	2,203,878	4,081,831	20.74	196,810
1998	5,612,195.05	3,075,623	2,374,158	4,641,086	21.34	217,483
1999	8,133,209.78	4,291,386	3,312,639	6,853,873	21.96	312,107
2000	6,445,858.15	3,269,581	2,523,880	5,533,443	22.58	245,059
2001	6,444,255.03	3,137,305	2,421,772	5,633,547	23.20	242,825
2002	7,072,547.59	3,294,304	2,542,964	6,297,720	23.84	264,166
2003	6,852,004.24	3,047,343	2,352,328	6,212,677	24.48	253,786
2004	7,363,757.68	3,117,447	2,406,443	6,798,254	25.13	270,523
2005	9,395,716.79	3,776,843	2,915,449	8,829,197	25.78	342,482
2006	9,632,569.48	3,662,905	2,827,498	9,213,214	26.44	348,457
2007	22,612,710.50	8,100,438	6,252,952	22,012,936	27.11	811,986
2008	33,744,136.33	11,344,357	8,757,023	33,423,147	27.78	1,203,137
2009	36,188,750.27	11,368,696	8,775,811	36,460,127	28.45	1,281,551
2010	11,770,418.36	3,434,314	2,651,042	12,061,981	29.13	414,074
2011	2,974,695.06	801,420	618,638	3,099,731	29.81	103,983
2012	22,785,496.44	5,621,467	4,339,366	24,142,505	30.50	791,558
2013	20,307,011.38	4,549,024	3,511,517	21,872,247	31.19	701,258
2014	14,309,689.48	2,876,069	2,220,117	15,666,995	31.89	491,282
2015	18,671,073.70	3,322,751	2,564,923	20,773,919	32.59	637,432
2016	19,203,679.94	2,975,370	2,296,770	21,707,830	33.29	652,083
2017	17,359,950.08	2,284,135	1,763,187	19,936,751	34.00	586,375
2018	19,661,794.44	2,127,898	1,642,583	22,934,660	34.71	660,751
2019	20,251,077.29	1,711,975	1,321,521	23,992,326	35.43	677,175
2020	23,479,207.10	1,421,079	1,096,970	28,252,039	36.16	781,306
2021	24,181,051.14	882,911	681,544	29,544,770	36.89	800,888
2022	39,672,809.47	483,016	372,853	49,218,159	37.63	1,307,950
	498,983,988.92	154,067,365	118,928,854	504,801,132		18,144,341

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.8 3.64

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS - DISTRIBUTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2003	7,589,830.51	2,303,134	2,439,736	5,150,095	38.31	134,432
2004	187,177.00	54,077	57,284	129,893	39.11	3,321
2008	14,500.04	3,327	3,524	10,976	42.38	259
2010	147,569.68	29,380	31,123	116,447	44.05	2,644
2011	32,674.59	6,006	6,362	26,313	44.89	586
2012	31,528.80	5,303	5,618	25,911	45.75	566
2013	1,635,016.20	249,716	264,527	1,370,489	46.60	29,410
2014	1,420,452.17	194,730	206,280	1,214,172	47.46	25,583
2015	2,191,394.63	265,750	281,512	1,909,883	48.33	39,518
2016	225,934.75	23,825	25,238	200,697	49.20	4,079
2017	9,701,609.72	867,809	919,280	8,782,330	50.08	175,366
2018	8,483,052.79	621,553	658,418	7,824,635	50.97	153,515
2019	871,745.25	49,925	52,886	818,859	51.85	15,793
2021	1,251,096.79	30,714	32,535	1,218,562	53.65	22,713
2022	277,125.71	2,267	2,402	274,724	54.55	5,036
	34,060,708.63	4,707,516	4,986,725	29,073,984		612,821
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.4						1.80

COMMON PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMMON PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PARK PLAZA						
INTERIM SURVIVOR CURVE.. IOWA 55-R2						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. 0						
1999	7,739,634.08	4,306,952	4,249,034	3,490,600	17.00	205,329
2000	101,850.00	55,587	54,839	47,011	17.07	2,754
2001	2,305,761.82	1,232,130	1,215,561	1,090,201	17.14	63,606
2002	1,831,013.44	956,412	943,551	887,463	17.21	51,567
2003	3,954,373.89	2,016,454	1,989,337	1,965,036	17.27	113,783
2005	61,205.10	29,556	29,159	32,047	17.39	1,843
2006	97,391.77	45,578	44,965	52,427	17.45	3,004
2007	299,539.90	135,575	133,752	165,788	17.50	9,474
2008	422,954.67	184,510	182,029	240,926	17.55	13,728
2009	73,762.13	30,889	30,474	43,289	17.60	2,460
2010	1,926,566.50	771,416	761,042	1,165,524	17.64	66,073
2011	4,123,166.98	1,568,411	1,547,320	2,575,847	17.69	145,610
2012	234,764.39	84,391	83,256	151,508	17.73	8,545
2013	3,064,569.05	1,031,810	1,017,935	2,046,634	17.77	115,174
2014	135,579.58	42,350	41,780	93,799	17.81	5,267
2015	3,144,307.40	900,530	888,420	2,255,887	17.84	126,451
2016	3,164,537.76	816,736	805,753	2,358,785	17.88	131,923
2017	1,366,703.27	311,171	306,986	1,059,717	17.91	59,169
2018	3,411,077.78	663,216	654,297	2,756,780	17.94	153,667
2019	2,783,263.53	438,225	432,332	2,350,932	17.98	130,753
2020	41,814.12	4,955	4,888	36,926	18.00	2,051
2021	168,141.85	12,516	12,348	155,794	18.03	8,641
2022	1,590,368.27	41,175	40,621	1,549,747	18.06	85,811
	42,042,347.28	15,680,545	15,469,678	26,572,669		1,506,683
LEASEHOLD IMPROVEMENTS						
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2013	448,419.39	68,487	448,419			
2015	1,406,396.41	170,554	1,205,360	201,036	48.33	4,160
2016	1,124,695.45	118,599	838,178	286,518	49.20	5,824
2017	780,839.96	69,846	493,624	287,216	50.08	5,735
2018	1,589,424.75	116,457	823,039	766,385	50.97	15,036

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMMON PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LEASEHOLD IMPROVEMENTS						
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2019	20,577,201.01	1,178,456	8,328,531	12,248,670	51.85	236,233
2020	1,458,885.06	59,683	421,799	1,037,086	52.75	19,660
2021	2,012,078.67	49,397	349,105	1,662,974	53.65	30,997
	29,397,940.70	1,831,479	12,908,055	16,489,885		317,645
	71,440,287.98	17,512,024	28,377,734	43,062,554		1,824,328
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					23.6	2.55

GAS PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 304.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1975	41,238.98	29,917	71,265	30,026-		
	41,238.98	29,917	71,265	30,026-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1.5						
NET SALVAGE PERCENT.. -5						
1975	1,923,020.00	1,575,478	2,019,171			
1976	53,326.00	43,158	55,992			
1977	567,289.80	453,484	595,654			
1978	504,296.08	397,832	529,511			
1979	89,442.31	69,595	93,914			
1980	268,327.24	205,822	281,744			
1982	55,095.23	40,982	57,850			
1983	136,041.07	99,502	142,843			
1984	47,332.38	34,031	49,699			
1985	139,639.84	98,584	146,622			
1986	172,412.66	119,386	181,033			
1989	21,873.00	14,221	22,967			
1990	275,794.39	175,198	289,584			
1991	13,913.00	8,627	14,609			
1992	69,005.00	41,719	72,455			
1996	1,265,505.00	681,518	1,328,780			
1998	2,747,021.00	1,383,749	2,884,372			
2022	8,778.00	99	1,315,918	1,306,702-		
	8,358,112.00	5,442,985	10,082,718	1,306,701-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R2						
NET SALVAGE PERCENT.. -5						
1975	41,202.00	41,439	43,262			
1977	87,427.19	86,094	91,799			
1978	64,117.35	62,442	67,323			
1979	5,927.45	5,708	6,224			
1980	27,326.29	26,018	28,693			
1981	25,861.87	24,343	27,155			
1992	2,357,841.00	1,890,395	2,475,733			
1993	16,893.00	13,265	17,738			
1994	87,538.00	67,262	91,915			
2018	54,773.13	8,195	57,512			
2019	28,736.61	3,362	30,173			
2020	30,256.14	2,542	31,769			
2021	1,522.48	77	1,087	512	26.65	19
2022	48,486.56	818	11,543	39,368	27.55	1,429
	2,877,909.07	2,231,960	2,981,926	39,879		1,448

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.5 0.05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S3						
NET SALVAGE PERCENT.. -5						
1921	23,390.50	24,560	24,560			
1942	20,577.24	20,504	21,606			
1947	42,882.96	42,001	45,027			
1948	262,642.89	256,250	275,775			
1949	30,316.59	29,470	31,832			
1952	5,650.00	5,425	5,932			
1954	193,918.07	184,556	203,614			
1955	61,233.82	58,007	64,296			
1956	1,577,707.38	1,487,620	1,656,593			
1958	75,109.61	70,111	78,865			
1959	514,400.30	477,574	540,120			
1960	54,412.49	50,243	57,133			
1961	19,548.48	17,948	20,526			
1970	11,560.65	9,961	12,139			
1971	22,601.05	19,308	23,731			
1972	405,115.00	342,934	425,371			
1973	2,006,356.36	1,682,390	2,106,674			
1974	113,282.81	94,039	118,947			
1975	2,987,223.76	2,454,064	3,136,585			
1976	156,481.88	127,140	164,306			
1977	202,805.24	162,861	212,946			
1978	59,390.30	47,107	62,360			
1979	29,622.00	23,197	31,103			
1980	176,392.00	136,279	185,212			
1981	244,938.00	186,562	257,185			
1982	273,045.00	204,817	286,697			
1983	314,004.00	231,848	329,704			
1985	453,981.00	323,856	476,680			
1986	493,056.00	345,208	517,709			
1989	118,713.00	78,055	124,649			
1990	309,507.00	198,824	324,982			
1991	35,904.00	22,506	37,699			
1992	19,081,959.34	11,652,971	20,036,057			
1998	1,792,305.08	904,827	1,881,920			
1999	849,447.00	412,602	891,919			
2001	4,900,742.68	2,190,044	5,145,780			
2007	11,496.00	3,735	12,071			
2015	451,769.91	71,154	474,358			
2016	727,439.00	99,295	763,811			
2017	68,551.85	7,918	71,979			

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S3						
NET SALVAGE PERCENT.. -5						
2018	138,964.00	13,132	145,912			
2019	37,808.81	2,779	39,699			
2021	23,907.45	753	1,046,586	1,021,483-		
	39,380,160.50	24,774,435	42,370,650	1,021,482-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 21-R1						
NET SALVAGE PERCENT.. 0						
1975	2,510.06	2,510	2,510			
1978	100,965.95	100,966	100,966			
1979	98,099.81	98,100	98,100			
1983	16,302.72	15,604	16,303			
1988	9,696.88	8,575	361,587	351,890-		
	227,575.42	225,755	579,466	351,890-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. 0						
2021	109,823.75	3,588	53,085-	162,909	43.53	3,742
2022	183,810.17	2,002	29,621-	213,431	44.51	4,795
	293,633.92	5,590	82,706-	376,340		8,537

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.1 2.91

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -5						
1975	4,687,701.83	3,570,728	4,745,414	176,673	15.10	11,700
1976	17,049.61	12,789	16,996	906	15.71	58
1981	144,410.23	99,415	132,120	19,511	18.94	1,030
1983	106,143.68	70,254	93,366	18,085	20.33	890
1992	111,177.13	59,133	78,587	38,149	27.14	1,406
	5,066,482.48	3,812,319	5,066,483	253,324		15,084

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.8 0.30

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2.5						
NET SALVAGE PERCENT.. -5						
1976	464,781.33	345,074	436,882	51,138	16.11	3,174
1989	154,637.25	91,399	115,716	46,653	24.04	1,941
1992	215,768.15	118,181	149,623	76,934	26.31	2,924
1993	23,149.79	12,330	15,610	8,697	27.10	321
1999	372,632.00	162,410	205,620	185,644	32.17	5,771
2007	111,515.57	32,743	41,454	75,637	39.62	1,909
2016	395.00	49	62	353	48.50	7
2017	100,438.98	10,546	13,352	92,109	49.50	1,861
2018	1,556,902.48	133,755	169,341	1,465,407	50.50	29,018
2019	72,743.45	4,861	6,154	70,227	51.50	1,364
2021	5,690,469.13	162,938	206,288	5,768,705	53.50	107,826
	8,763,433.13	1,074,286	1,360,102	7,841,503		156,116

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.2 1.78

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 363.40 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2.5						
NET SALVAGE PERCENT.. -5						
1975	719,609.43	541,002	755,590			
1992	10,970.34	6,009	11,519			
1996	19,220.03	9,335	20,181			
1997	48,006.92	22,528	50,407			
2012	447,960.99	89,627	470,359			
2015	947,544.13	135,488	793,822	201,099	47.51	4,233
2016	222,880.00	27,657	162,042	71,982	48.50	1,484
2017	803,024.59	84,318	494,018	349,158	49.50	7,054
2018	275,692.32	23,685	138,770	150,707	50.50	2,984
2019	622,561.83	41,601	243,739	409,951	51.50	7,960
2021	520,772.12	14,912	87,369	459,442	53.50	8,588
2022	789,944.46	7,540	44,177	785,265	54.50	14,409
	5,428,187.16	1,003,702	3,271,993	2,427,604		46,712

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.0 0.86

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S2.5						
NET SALVAGE PERCENT.. -10						
1958	6,876.17	5,617	7,542	22	18.02	1
1963	6,169.66	4,814	6,464	323	20.35	16
1975	14,458,163.97	9,717,332	13,047,147	2,856,833	27.23	104,915
1976	1,883,950.68	1,246,371	1,673,462	398,884	27.90	14,297
1977	1,605,321.06	1,044,873	1,402,917	362,936	28.58	12,699
1978	283,885.86	181,700	243,963	68,311	29.27	2,334
1980	16,509.85	10,196	13,690	4,471	30.70	146
1981	5,493.00	3,328	4,468	1,574	31.44	50
1982	41,044.46	24,387	32,744	12,405	32.19	385
1983	372,164.60	216,681	290,931	118,450	32.95	3,595
1984	17,611.65	10,038	13,478	5,895	33.73	175
1985	1,031,230.69	574,959	771,979	362,375	34.52	10,498
1986	294,312.89	160,347	215,293	108,451	35.33	3,070
1987	120,581.10	64,140	86,119	46,520	36.15	1,287
1988	7,358,257.79	3,818,060	5,126,386	2,967,698	36.98	80,251
1989	661,892.48	334,706	449,399	278,683	37.82	7,369
1991	5,347,913.31	2,559,800	3,436,960	2,445,745	39.54	61,855
1992	10,606,616.50	4,930,242	6,619,676	5,047,602	40.42	124,879
1993	2,815,165.46	1,269,206	1,704,122	1,392,560	41.31	33,710
1994	125,501.81	54,826	73,613	64,439	42.20	1,527
1995	2,712,579.62	1,146,211	1,538,980	1,444,858	43.11	33,516
1996	2,059,999.19	840,686	1,128,762	1,137,237	44.03	25,829
1998	1,826,870.11	692,433	929,707	1,079,850	45.88	23,536
1999	145,035.54	52,830	70,933	88,606	46.82	1,892
2001	5,081,720.99	1,698,545	2,280,582	3,309,311	48.73	67,911
2002	138,949.24	44,346	59,542	93,302	49.69	1,878
2005	13,803,410.23	3,774,225	5,067,530	10,116,221	52.60	192,324
2006	5,601,638.91	1,445,374	1,940,657	4,221,146	53.58	78,782
2007	27,720.77	6,726	9,031	21,462	54.56	393
2008	80,233.84	18,231	24,478	63,779	55.54	1,148
2009	472,872.37	100,094	134,393	385,767	56.53	6,824
2010	53,383.98	10,470	14,058	44,664	57.52	776
2011	29,633.75	5,346	7,178	25,419	58.52	434
2012	107,292.03	17,687	23,748	94,273	59.51	1,584
2015	852,259.68	100,442	134,860	802,626	62.50	12,842
2017	8,923,916.33	771,267	1,035,555	8,780,753	64.50	136,136
2018	2,520,677.56	178,260	239,344	2,533,401	65.50	38,678
2019	1,727,301.10	95,002	127,556	1,772,475	66.50	26,654

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S2.5						
NET SALVAGE PERCENT.. -10						
2020	532,500.13	20,917	28,084	557,666	67.50	8,262
2021	30,185.61	712	956	32,248	68.50	471
2022	2.73		0	3	69.50	
	93,786,846.70	37,251,427	50,016,287	53,149,244		1,122,929
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.3	1.20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S2.5						
NET SALVAGE PERCENT.. -10						
1990	1,138.63	1,007	114	1,138	5.88	194
1991	3,058,825.72	2,667,103	301,486	3,063,222	6.22	492,479
1992	424,972.31	364,939	41,252	426,218	6.58	64,775
1993	646,889.50	546,492	61,775	649,803	6.96	93,362
1994	9.00	7	1	9	7.36	1
1995	853.35	695	79	860	7.79	110
1996	14,225.45	11,350	1,283	14,365	8.24	1,743
1997	77,206.16	60,241	6,809	78,118	8.72	8,958
2021	112,292.12	6,176	698	122,823	28.50	4,310
2022	8.22		0	9	29.50	
	4,336,420.46	3,658,010	413,497	4,356,565		665,932

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 15.36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 374.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1997	54,865.26	23,682	29,301	25,565	31.26	818
	54,865.26	23,682	29,301	25,565		818

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.3 1.49

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-S2.5						
NET SALVAGE PERCENT.. -5						
1957	17,840.42	15,111	18,732			
1964	110,484.14	88,727	116,008			
1966	58,465.83	46,114	61,056	333	14.93	22
1968	44,816.42	34,666	45,899	1,158	15.80	73
1970	14,286.39	10,823	14,330	671	16.71	40
1975	6,459,306.18	4,605,162	6,097,378	684,893	19.26	35,560
1976	1,238,235.48	870,670	1,152,794	147,353	19.82	7,435
1977	487,734.81	338,087	447,638	64,484	20.39	3,163
1978	3,544,983.95	2,421,313	3,205,894	516,339	20.97	24,623
1979	305,342.17	205,296	271,818	48,791	21.58	2,261
1980	480,784.30	318,039	421,094	83,730	22.20	3,772
1981	314,639.40	204,665	270,983	59,388	22.83	2,601
1982	795,439.01	508,368	673,095	162,116	23.48	6,904
1983	4,336,153.27	2,720,394	3,601,886	951,075	24.15	39,382
1984	560,341.28	344,778	456,497	131,861	24.84	5,308
1985	679,410.16	409,716	542,477	170,904	25.54	6,692
1986	841,472.48	496,844	657,837	225,709	26.26	8,595
1987	502,731.49	290,327	384,402	143,466	27.00	5,314
1988	486,309.83	274,461	363,395	147,230	27.75	5,306
1989	3,390,409.21	1,867,788	2,473,009	1,086,921	28.52	38,111
1990	626,988.29	336,740	445,854	212,484	29.31	7,250
1991	2,516,567.22	1,316,362	1,742,904	899,492	30.11	29,874
1992	6,700,718.06	3,410,019	4,514,971	2,520,783	30.92	81,526
1993	3,265,776.06	1,614,507	2,137,657	1,291,408	31.75	40,674
1994	786,387.46	377,076	499,260	326,447	32.60	10,014
1995	701,836.38	325,965	431,588	305,340	33.46	9,126
1996	410,598.88	184,450	244,218	186,911	34.33	5,445
1997	2,127,962.63	923,171	1,222,307	1,012,054	35.21	28,743
1998	2,544,550.78	1,063,822	1,408,533	1,263,245	36.11	34,983
1999	103,142.28	41,479	54,919	53,380	37.02	1,442
2003	1,111,866.00	374,754	496,186	671,273	40.74	16,477
2006	727,121.09	208,429	275,966	487,511	43.62	11,176
2007	4,020.00	1,084	1,435	2,786	44.59	62
2010	20,335.39	4,434	5,871	15,481	47.54	326
2017	7,813,799.79	752,106	995,812	7,208,678	54.50	132,269
2018	41,014,317.89	3,229,878	4,276,459	38,788,575	55.50	698,893
2019	176,302.80	10,798	14,297	170,821	56.50	3,023

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-S2.5						
NET SALVAGE PERCENT.. -5						
2020	587,208.84	25,692	34,017	582,552	57.50	10,131
2021	4,603,404.75	120,839	159,995	4,673,580	58.50	79,890
2022	2,577,121.48	22,541	29,845	2,676,133	59.50	44,977
	103,089,212.29	30,415,495	40,268,316	67,975,357		1,441,463
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.2	1.40

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. -30						
1923	552,332.82	624,976	627,035	90,998	9.72	9,362
1924	1,236,888.33	1,394,418	1,399,011	208,944	9.96	20,978
1925	1,251,701.48	1,405,472	1,410,102	217,110	10.22	21,244
1926	1,357,018.12	1,517,852	1,522,852	241,272	10.47	23,044
1927	1,326,187.43	1,477,161	1,482,027	242,017	10.74	22,534
1928	1,174,974.21	1,303,234	1,307,527	219,939	11.01	19,976
1929	1,086,406.53	1,199,914	1,203,866	208,462	11.28	18,481
1930	700,389.77	770,170	772,707	137,800	11.56	11,920
1931	531,308.88	581,660	583,576	107,126	11.84	9,048
1932	288,974.10	314,857	315,894	59,772	12.14	4,924
1933	120,381.36	130,538	130,968	25,528	12.44	2,052
1934	193,665.92	208,966	209,654	42,112	12.75	3,303
1935	133,368.25	143,164	143,636	29,743	13.07	2,276
1936	255,047.43	272,368	273,265	58,297	13.39	4,354
1937	337,262.01	358,175	359,355	79,086	13.73	5,760
1938	445,802.80	470,746	472,297	107,247	14.08	7,617
1939	594,133.82	623,669	625,723	146,651	14.44	10,156
1940	772,954.13	806,555	809,212	195,628	14.80	13,218
1941	672,606.13	697,412	699,709	174,679	15.18	11,507
1942	395,821.00	407,743	409,086	105,481	15.57	6,775
1943	393,885.31	403,020	404,348	107,703	15.97	6,744
1944	188,446.99	191,445	192,076	52,905	16.39	3,228
1945	193,621.91	195,293	195,936	55,772	16.81	3,318
1946	614,567.18	615,182	617,208	181,729	17.25	10,535
1947	2,102,447.68	2,088,506	2,095,385	637,797	17.69	36,054
1948	4,249,577.14	4,187,533	4,201,327	1,323,123	18.15	72,899
1949	3,166,438.75	3,094,399	3,104,592	1,011,778	18.62	54,338
1950	1,529,705.46	1,481,917	1,486,798	501,819	19.11	26,259
1951	5,565,178.54	5,344,080	5,361,683	1,873,049	19.60	95,564
1952	7,292,113.68	6,939,175	6,962,032	2,517,716	20.10	125,260
1953	13,941,446.61	13,141,082	13,184,368	4,939,513	20.62	239,550
1954	18,808,547.11	17,555,898	17,613,727	6,837,384	21.15	323,281
1955	8,516,381.55	7,869,477	7,895,399	3,175,897	21.69	146,422
1956	9,394,235.38	8,591,132	8,619,431	3,593,075	22.24	161,559
1957	8,472,082.44	7,665,540	7,690,790	3,322,917	22.80	145,742
1958	8,094,972.97	7,244,353	7,268,216	3,255,249	23.37	139,292
1959	8,323,775.82	7,365,468	7,389,730	3,431,179	23.95	143,264
1960	9,288,782.02	8,124,340	8,151,101	3,924,316	24.54	159,915
1961	8,605,052.18	7,436,830	7,461,327	3,725,241	25.14	148,180
1962	9,676,500.96	8,260,548	8,287,758	4,291,693	25.75	166,668
1963	10,279,036.37	8,664,405	8,692,945	4,669,802	26.37	177,088

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. -30						
1964	9,590,001.23	7,978,881	8,005,163	4,461,839	27.00	165,253
1965	9,450,721.95	7,758,202	7,783,757	4,502,182	27.64	162,886
1966	9,502,214.13	7,693,373	7,718,715	4,634,163	28.29	163,809
1967	9,579,149.18	7,646,077	7,671,263	4,781,631	28.95	165,169
1968	12,919,795.51	10,164,778	10,198,261	6,597,473	29.61	222,812
1969	11,720,155.92	9,084,891	9,114,816	6,121,387	30.28	202,159
1970	10,873,208.01	8,300,172	8,327,513	5,807,657	30.96	187,586
1971	9,813,763.33	7,374,062	7,398,352	5,359,540	31.65	169,338
1972	11,109,133.31	8,212,660	8,239,712	6,202,161	32.35	191,721
1973	10,805,034.97	7,856,654	7,882,534	6,164,011	33.05	186,506
1974	8,322,618.54	5,949,266	5,968,863	4,850,541	33.76	143,677
1975	6,277,281.51	4,408,855	4,423,378	3,737,088	34.48	108,384
1976	7,158,773.73	4,937,327	4,953,590	4,352,816	35.21	123,624
1977	9,059,268.67	6,133,487	6,153,691	5,623,358	35.94	156,465
1978	12,385,288.01	8,226,420	8,253,518	7,847,356	36.68	213,941
1979	19,735,764.71	12,852,108	12,894,443	12,762,051	37.43	340,958
1980	23,231,669.20	14,826,660	14,875,499	15,325,671	38.18	401,406
1981	24,375,924.59	15,235,928	15,286,115	16,402,587	38.94	421,227
1982	25,892,113.63	15,842,633	15,894,818	17,764,930	39.70	447,479
1983	28,756,916.26	17,206,730	17,263,408	20,120,583	40.48	497,050
1984	30,787,614.36	18,005,551	18,064,861	21,959,038	41.26	532,211
1985	40,125,409.11	22,924,088	22,999,599	29,163,433	42.04	693,707
1986	47,251,341.62	26,347,773	26,434,562	34,992,182	42.83	817,002
1987	50,738,040.59	27,588,860	27,679,737	38,279,716	43.63	877,371
1988	53,616,351.07	28,410,232	28,503,815	41,197,441	44.43	927,244
1989	47,344,639.19	24,422,259	24,502,705	37,045,326	45.24	818,862
1990	51,465,298.62	25,825,287	25,910,355	40,994,533	46.05	890,218
1991	48,047,986.42	23,427,766	23,504,936	38,957,446	46.87	831,181
1992	44,858,594.86	21,227,087	21,297,008	37,019,165	47.70	776,083
1993	54,104,482.03	24,823,623	24,905,391	45,430,436	48.53	936,131
1994	49,747,721.63	22,100,376	22,173,174	42,498,864	49.37	860,824
1995	51,003,159.16	21,915,496	21,987,685	44,316,422	50.21	882,621
1996	40,217,236.19	16,695,341	16,750,335	35,532,072	51.05	696,025
1997	45,701,055.90	18,290,979	18,351,229	41,060,144	51.91	790,987
1998	51,767,800.36	19,955,918	20,021,652	47,276,488	52.76	896,067
1999	59,100,342.20	21,902,055	21,974,200	54,856,245	53.62	1,023,056
2000	64,964,838.09	23,095,715	23,171,792	61,282,498	54.49	1,124,656
2001	62,587,179.86	21,306,616	21,376,799	59,986,535	55.36	1,083,572
2002	63,949,635.51	20,794,439	20,862,935	62,271,591	56.24	1,107,247
2003	58,323,077.98	18,085,345	18,144,918	57,675,083	57.11	1,009,895
2004	65,847,665.96	19,403,398	19,467,312	66,134,654	58.00	1,140,253

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. -30						
2005	82,997,741.85	23,176,289	23,252,631	84,644,433	58.89	1,437,331
2006	79,819,488.28	21,057,099	21,126,461	82,638,874	59.78	1,382,383
2007	66,149,375.41	16,418,870	16,472,953	69,521,235	60.68	1,145,703
2008	92,320,658.80	21,474,616	21,545,353	98,471,503	61.58	1,599,083
2009	106,384,867.58	23,086,474	23,162,520	115,137,808	62.48	1,842,795
2010	155,252,293.86	31,242,972	31,345,886	170,482,096	63.39	2,689,416
2011	78,746,023.22	14,605,104	14,653,213	87,716,617	64.30	1,364,178
2012	54,535,261.54	9,254,034	9,284,517	61,611,323	65.21	944,814
2013	59,858,217.86	9,203,261	9,233,576	68,582,107	66.13	1,037,080
2014	52,217,915.97	7,195,629	7,219,331	60,663,960	67.05	904,757
2015	91,463,169.06	11,129,238	11,165,897	107,736,223	67.98	1,584,822
2016	108,281,518.06	11,448,497	11,486,208	129,279,765	68.90	1,876,339
2017	182,679,927.67	16,338,893	16,392,713	221,091,193	69.84	3,165,681
2018	170,466,659.06	12,498,615	12,539,785	209,066,872	70.77	2,954,174
2019	197,064,022.74	11,272,062	11,309,192	244,874,038	71.70	3,415,259
2020	269,143,435.14	11,010,927	11,047,197	338,839,269	72.64	4,664,638
2021	218,134,392.01	5,368,069	5,385,752	278,188,958	73.58	3,780,769
2022	199,142,966.25	1,623,214	1,628,561	257,257,295	74.53	3,451,728
	3,768,890,222.03	1,052,809,904	1,056,277,834	3,843,279,455		65,241,302
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					58.9	1.73

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -10						
1908	4,010.14	4,411	4,411			
1909	10,572.77	11,630	11,630			
1910	1,838.28	2,022	2,022			
1911	1,580.16	1,738	1,738			
1912	780.01	858	858			
1913	1,681.57	1,850	1,850			
1914	844.54	929	929			
1915	391.73	431	431			
1916	593.36	653	653			
1917	1,736.88	1,911	1,911			
1918	593.36	653	653			
1919	639.46	703	703			
1920	1,216.54	1,338	1,338			
1921	2,407.44	2,648	2,648			
1922	4,189.11	4,608	4,608			
1923	4,626.93	5,090	5,090			
1924	3,027.17	3,330	3,330			
1925	4,856.22	5,342	5,342			
1926	7,663.31	8,430	8,430			
1927	8,243.19	9,068	9,068			
1928	8,772.01	9,649	9,649			
1929	2,862.40	3,149	3,149			
1930	2,666.54	2,933	2,933			
1931	8,010.45	8,811	8,811			
1932	1,135.71	1,249	1,249			
1933	602.58	663	663			
1934	260.40	286	286			
1935	1,700.01	1,870	1,870			
1936	3,418.89	3,761	3,761			
1937	3,054.82	3,360	3,360			
1938	3,280.50	3,609	3,609			
1939	8,215.54	9,017	8,906	131	0.12	131
1940	8,285.94	9,053	8,941	174	0.37	174
1941	7,089.35	7,725	7,630	168	0.52	168
1942	3,871.00	4,204	4,152	106	0.70	106
1943	6,832.66	7,393	7,302	214	0.90	214
1944	4,370.77	4,711	4,653	155	1.11	140
1945	7,158.80	7,683	7,588	287	1.34	214
1946	12,720.58	13,596	13,428	565	1.56	362
1947	29,694.79	31,607	31,217	1,447	1.78	813
1948	54,453.28	57,699	56,987	2,912	2.02	1,442

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -10						
1949	57,092.17	60,221	59,477	3,324	2.26	1,471
1950	53,736.96	56,413	55,716	3,395	2.51	1,353
1951	97,578.62	101,950	100,691	6,645	2.76	2,408
1952	113,311.94	117,799	116,345	8,298	3.02	2,748
1953	43,460.12	44,964	44,409	3,397	3.27	1,039
1954	159,331.61	163,985	161,960	13,305	3.54	3,758
1955	156,438.18	160,162	158,184	13,898	3.81	3,648
1956	160,866.43	163,827	161,804	15,149	4.08	3,713
1957	136,758.94	138,510	136,800	13,635	4.36	3,127
1958	42,781.90	43,090	42,558	4,502	4.64	970
1959	199,592.93	199,872	197,404	22,148	4.93	4,492
1960	242,393.85	241,279	238,300	28,333	5.23	5,417
1961	29,838.35	29,510	29,146	3,676	5.55	662
1962	161,864.44	159,015	157,052	20,999	5.88	3,571
1963	93,471.43	91,191	90,065	12,754	6.22	2,050
1964	67,663.17	65,511	64,702	9,727	6.59	1,476
1965	42,434.60	40,763	40,260	6,418	6.97	921
1966	38,985.19	37,130	36,672	6,212	7.38	842
1967	48,766.38	46,016	45,448	8,195	7.82	1,048
1968	61,455.43	57,411	56,702	10,899	8.29	1,315
1969	71,360.33	65,965	65,151	13,345	8.78	1,520
1970	114,548.92	104,675	103,383	22,621	9.31	2,430
1971	101,341.13	91,491	90,361	21,114	9.86	2,141
1972	171,579.98	152,912	151,024	37,714	10.44	3,612
1973	74,498.65	65,484	64,675	17,274	11.05	1,563
1974	112,411.69	97,394	96,191	27,462	11.68	2,351
1975	60,062.06	51,245	50,612	15,456	12.34	1,253
1976	28,884.25	24,263	23,963	7,810	13.00	601
1977	155,847.79	128,792	127,202	44,231	13.68	3,233
1978	52,190.18	42,400	41,876	15,533	14.38	1,080
1979	74,990.26	59,872	59,133	23,356	15.08	1,549
1980	131,989.21	103,480	102,202	42,986	15.80	2,721
1981	581,056.99	447,062	441,542	197,621	16.53	11,955
1982	888,299.12	670,135	661,861	315,268	17.28	18,245
1983	917,542.40	678,247	669,873	339,424	18.04	18,815
1984	559,716.21	405,123	400,121	215,567	18.81	11,460
1985	1,007,816.25	713,538	704,728	403,870	19.60	20,606
1986	1,140,524.99	789,242	779,497	475,080	20.40	23,288
1987	974,749.23	658,732	650,599	421,625	21.21	19,879
1988	1,656,052.55	1,091,665	1,078,186	743,472	22.04	33,733
1989	2,698,353.24	1,733,422	1,712,019	1,256,170	22.88	54,903

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -10						
1990	3,169,465.62	1,982,200	1,957,726	1,528,686	23.73	64,420
1991	2,729,712.32	1,659,673	1,639,181	1,363,503	24.60	55,427
1992	2,753,114.25	1,625,992	1,605,916	1,422,510	25.47	55,850
1993	2,705,977.56	1,549,992	1,530,854	1,445,721	26.36	54,845
1994	3,275,305.75	1,817,811	1,795,366	1,807,470	27.25	66,329
1995	1,102,076.15	591,594	584,290	627,994	28.16	22,301
1996	888,188.42	460,434	454,749	522,258	29.08	17,959
1997	1,691,659.47	845,838	835,394	1,025,431	30.00	34,181
1998	310,081.73	149,275	147,432	193,658	30.93	6,261
1999	223,646.56	103,460	102,183	143,828	31.87	4,513
2000	95,622.96	42,418	41,894	63,291	32.82	1,928
2001	517,408.94	219,692	216,979	352,171	33.77	10,429
2002	2,172,245.54	880,639	869,766	1,519,704	34.73	43,758
2003	960,092.77	370,597	366,021	690,081	35.70	19,330
2004	2,700,063.29	989,835	977,614	1,992,456	36.67	54,335
2005	3,247,082.95	1,127,400	1,113,480	2,458,311	37.64	65,311
2006	2,925,679.92	958,459	946,625	2,271,623	38.62	58,820
2007	6,531,044.43	2,011,562	1,986,725	5,197,424	39.60	131,248
2008	4,263,142.98	1,229,482	1,214,302	3,475,155	40.58	85,637
2009	5,925,596.61	1,592,777	1,573,111	4,945,045	41.56	118,986
2010	11,144,765.21	2,775,002	2,740,739	9,518,503	42.55	223,702
2011	5,279,092.20	1,209,947	1,195,008	4,611,993	43.54	105,925
2012	2,422,293.33	507,219	500,956	2,163,567	44.53	48,587
2013	2,195,191.75	415,765	410,632	2,004,079	45.53	44,017
2015	4,779,052.38	714,946	706,118	4,550,840	47.52	95,767
2016	4,275,352.58	554,941	548,089	4,154,799	48.51	85,648
2017	8,757,653.75	961,608	949,735	8,683,684	49.51	175,393
2018	1,817,243.33	163,196	161,181	1,837,787	50.51	36,385
2019	3,627,167.79	253,916	250,781	3,739,104	51.50	72,604
2020	10,100,457.63	504,972	498,737	10,611,766	52.50	202,129
2021	15,080,252.65	452,362	446,777	16,141,501	53.50	301,710
2022	23,565,585.81	235,632	232,722	25,689,422	54.50	471,366
	155,052,903.89	39,412,065	38,926,764	131,631,430		3,121,832

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.2 2.01

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -10						
1961	8,832.84	8,232	9,716			
1962	21,431.78	19,816	23,575			
1975	3,948,146.50	3,150,601	3,854,345	488,616	15.10	32,359
1976	1,006,309.82	790,754	967,383	139,558	15.71	8,883
1977	3,018,771.42	2,335,313	2,856,948	463,701	16.32	28,413
1978	923,126.96	702,319	859,195	156,245	16.96	9,213
1979	1,312,066.59	981,166	1,200,327	242,946	17.61	13,796
1980	1,769,250.42	1,299,695	1,590,006	356,169	18.27	19,495
1981	1,267,754.42	914,310	1,118,538	275,992	18.94	14,572
1982	1,491,693.07	1,055,222	1,290,925	349,937	19.63	17,827
1983	1,869,296.95	1,296,163	1,585,685	470,542	20.33	23,145
1984	1,781,179.23	1,209,768	1,479,992	479,305	21.04	22,781
1985	1,022,424.83	679,501	831,280	293,387	21.77	13,477
1986	6,290,064.18	4,088,548	5,001,800	1,917,271	22.50	85,212
1987	2,769,885.32	1,758,869	2,151,745	895,129	23.25	38,500
1988	607,167.90	376,320	460,378	207,507	24.01	8,643
1989	5,983,829.22	3,617,847	4,425,959	2,156,253	24.77	87,051
1990	1,159,045.72	682,672	835,159	439,791	25.55	17,213
1991	996,176.17	571,007	698,552	397,242	26.34	15,081
1992	2,683,077.27	1,495,024	1,828,965	1,122,420	27.14	41,357
1993	3,209,295.55	1,736,871	2,124,833	1,405,392	27.94	50,300
1994	10,321,644.65	5,416,789	6,626,728	4,727,081	28.76	164,363
1995	3,302,875.53	1,678,521	2,053,449	1,579,714	29.59	53,387
1996	4,299,961.93	2,113,866	2,586,037	2,143,921	30.42	70,477
1997	2,360,100.79	1,120,585	1,370,888	1,225,223	31.26	39,195
1998	5,728,496.70	2,622,494	3,208,276	3,093,070	32.11	96,327
1999	1,220,869.67	537,921	658,075	684,882	32.97	20,773
2001	175,954.67	71,368	87,309	106,241	34.72	3,060
2002	1,946,228.65	755,143	923,818	1,217,034	35.60	34,186
2003	202,740.81	75,056	91,821	131,194	36.49	3,595
2010	1,449,460.91	349,893	428,048	1,166,359	42.93	27,169
2012	3,551,293.48	723,743	885,404	3,021,019	44.81	67,418
2014	2,871,202.19	475,485	581,693	2,576,629	46.72	55,150
2015	976,467.45	142,761	174,649	899,465	47.69	18,861
2017	3,834,897.20	412,643	504,815	3,713,572	49.62	74,840
2020	16,414,854.21	807,660	988,066	17,068,274	52.54	324,862
2021	814,427.42	24,108	29,493	866,377	53.52	16,188
	102,610,302.42	46,098,054	56,393,875	56,477,458		1,617,169

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.9 1.58

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -60						
1947	107,698.54	148,591	116,363	55,955	8.95	6,252
1948	672,302.46	921,947	721,988	353,696	9.29	38,073
1949	846,922.39	1,154,321	903,963	451,113	9.63	46,845
1950	1,203,070.47	1,629,073	1,275,747	649,166	9.99	64,982
1951	1,470,932.55	1,978,393	1,549,304	804,188	10.36	77,624
1952	1,558,184.76	2,080,787	1,629,490	863,606	10.75	80,335
1954	1,701,967.73	2,238,836	1,753,260	969,888	11.56	83,900
1955	2,250,282.83	2,936,313	2,299,463	1,300,990	11.99	108,506
1956	2,543,205.91	3,290,990	2,577,215	1,491,914	12.43	120,025
1957	2,743,519.42	3,519,826	2,756,420	1,633,211	12.88	126,802
1958	3,258,074.62	4,142,290	3,243,879	1,969,040	13.35	147,494
1959	3,988,840.62	5,023,259	3,933,777	2,448,368	13.84	176,905
1960	3,679,325.25	4,589,090	3,593,774	2,293,146	14.33	160,024
1961	3,373,818.79	4,164,858	3,261,552	2,136,558	14.85	143,876
1962	4,637,791.97	5,664,636	4,436,047	2,984,420	15.38	194,046
1963	5,147,202.00	6,218,479	4,869,768	3,365,755	15.92	211,417
1964	5,566,776.18	6,648,601	5,206,602	3,700,240	16.48	224,529
1965	5,302,416.91	6,258,464	4,901,081	3,582,786	17.05	210,134
1966	6,221,249.90	7,254,176	5,680,836	4,273,164	17.63	242,380
1967	6,917,828.28	7,964,247	6,236,901	4,831,624	18.23	265,037
1968	7,830,461.56	8,897,284	6,967,574	5,561,164	18.84	295,179
1969	8,477,734.39	9,503,472	7,442,287	6,122,088	19.46	314,599
1970	8,449,870.42	9,339,067	7,313,540	6,206,253	20.10	308,769
1971	4,520,432.11	4,923,799	3,855,888	3,376,803	20.75	162,737
1972	10,988,431.82	11,790,499	9,233,287	8,348,204	21.41	389,921
1973	10,812,675.80	11,423,549	8,945,924	8,354,357	22.08	378,368
1974	9,863,565.00	10,255,740	8,031,398	7,750,306	22.76	340,523
1975	7,582,234.73	7,754,867	6,072,933	6,058,643	23.45	258,364
1976	2,575,129.34	2,588,767	2,027,296	2,092,911	24.16	86,627
1977	8,121,045.53	8,022,034	6,282,155	6,711,518	24.87	269,864
1978	14,119,697.16	13,697,462	10,726,653	11,864,862	25.59	463,652
1979	12,115,855.90	11,532,744	9,031,435	10,353,934	26.33	393,237
1980	26,906,273.79	25,121,419	19,672,896	23,377,142	27.07	863,581
1981	22,557,176.47	20,644,328	16,166,830	19,924,652	27.82	716,199
1982	23,454,291.45	21,026,678	16,466,253	21,060,613	28.58	736,900
1983	24,844,496.54	21,801,940	17,073,371	22,677,823	29.35	772,669
1984	30,890,406.85	26,514,348	20,763,716	28,660,935	30.13	951,242
1985	33,908,311.46	28,453,685	22,282,435	31,970,863	30.91	1,034,321
1986	38,552,749.96	31,591,665	24,739,826	36,944,574	31.71	1,165,076
1987	39,279,151.42	31,413,894	24,600,612	38,246,030	32.51	1,176,439
1988	38,075,207.06	29,691,351	23,251,667	37,668,664	33.32	1,130,512

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -60						
1989	38,814,830.74	29,484,988	23,090,061	39,013,668	34.14	1,142,755
1990	40,674,172.84	30,076,110	23,552,976	41,525,701	34.96	1,187,806
1991	41,027,971.97	29,489,593	23,093,668	42,551,087	35.80	1,188,578
1992	44,489,994.98	31,058,288	24,322,132	46,861,860	36.64	1,278,981
1993	46,809,237.90	31,697,718	24,822,878	50,071,903	37.49	1,335,607
1994	56,409,477.25	37,018,155	28,989,378	61,265,786	38.34	1,597,960
1995	48,824,792.56	30,995,541	24,272,994	53,846,674	39.21	1,373,289
1996	51,501,934.95	31,591,699	24,739,853	57,663,243	40.08	1,438,704
1997	51,908,775.73	30,729,995	24,065,042	58,988,999	40.95	1,440,513
1998	60,585,990.94	34,554,372	27,059,959	69,877,627	41.83	1,670,515
1999	47,023,362.59	25,789,117	20,195,779	55,041,601	42.72	1,288,427
2000	49,608,263.82	26,107,440	20,445,062	58,928,160	43.62	1,350,944
2001	47,675,781.53	24,034,696	18,821,870	57,459,380	44.52	1,290,642
2002	56,426,710.38	27,182,326	21,286,818	68,995,919	45.43	1,518,730
2003	63,879,773.01	29,341,768	22,977,904	79,229,733	46.34	1,709,748
2004	60,517,410.97	26,426,259	20,694,733	76,133,125	47.26	1,610,942
2005	64,788,850.57	26,824,657	21,006,723	82,655,438	48.18	1,715,555
2006	67,222,554.15	26,293,161	20,590,502	86,965,585	49.11	1,770,833
2007	66,732,493.30	24,557,558	19,231,330	87,540,659	50.05	1,749,064
2008	71,167,203.76	24,543,007	19,219,935	94,647,591	50.99	1,856,199
2009	82,773,336.21	26,630,500	20,854,676	111,582,662	51.93	2,148,713
2010	88,647,443.96	26,446,724	20,710,759	121,125,151	52.88	2,290,566
2011	73,245,263.02	20,139,518	15,771,507	101,420,914	53.83	1,884,096
2012	74,616,216.32	18,771,052	14,699,845	104,686,101	54.78	1,911,028
2013	88,010,741.82	20,060,816	15,709,875	125,107,312	55.74	2,244,480
2014	189,039,666.65	38,576,191	30,209,496	272,253,971	56.71	4,800,811
2015	315,532,094.82	56,932,087	44,584,227	460,267,125	57.67	7,981,050
2016	396,260,143.62	62,038,488	48,583,113	585,433,117	58.64	9,983,512
2017	349,579,771.57	46,379,447	36,320,323	523,007,312	59.61	8,773,818
2018	470,613,574.54	51,089,810	40,009,066	712,972,653	60.59	11,767,167
2019	389,520,638.15	32,981,491	25,828,217	597,404,804	61.56	9,704,432
2020	343,189,382.10	20,783,549	16,275,856	532,827,155	62.54	8,519,782
2021	475,102,622.71	17,308,939	13,554,846	746,609,350	63.52	11,753,926
2022	505,465,787.02	6,097,939	4,775,371	803,969,888	64.51	12,462,717
	5,364,802,876.79	1,445,848,768	1,132,262,180	7,451,422,422		140,679,855
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					53.0	2.62

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -10						
1964	17.67	15	11-	30	6.14	5
1965	136.88	113	79-	230	6.26	37
1966	154.56	127	89-	259	6.39	41
1967	922.95	750	525-	1,540	6.52	236
1968	1,077.34	870	610-	1,795	6.65	270
1969	4,409.44	3,533	2,475-	7,325	6.79	1,079
1970	10,316.94	8,198	5,744-	17,093	6.94	2,463
1971	10,146.63	7,996	5,602-	16,763	7.09	2,364
1972	19,444.06	15,186	10,640-	32,028	7.25	4,418
1973	17,765.33	13,750	9,634-	29,176	7.41	3,937
1974	26,268.29	20,134	14,107-	43,002	7.58	5,673
1975	17,575.62	13,340	9,347-	28,680	7.75	3,701
1976	26,470.62	19,882	13,930-	43,048	7.93	5,428
1977	28,173.99	20,938	14,670-	45,661	8.11	5,630
1978	68,270.58	50,165	35,148-	110,246	8.30	13,283
1979	160,918.24	116,897	81,903-	258,913	8.49	30,496
1980	84,481.69	60,627	42,478-	135,408	8.69	15,582
1981	94,255.19	66,812	46,811-	150,492	8.89	16,928
1982	313,940.69	219,633	153,883-	499,218	9.10	54,859
1983	440,093.96	303,823	212,870-	696,973	9.31	74,863
1984	668,724.48	455,187	318,922-	1,054,519	9.53	110,653
1985	836,003.66	560,958	393,029-	1,312,633	9.75	134,629
1986	965,381.42	638,001	447,008-	1,508,928	9.98	151,195
1987	1,057,706.64	687,848	481,933-	1,645,410	10.22	160,999
1988	970,200.59	620,696	434,883-	1,502,104	10.46	143,605
1989	962,401.49	605,543	424,267-	1,482,909	10.70	138,590
1990	1,388,690.53	858,488	601,490-	2,129,050	10.95	194,434
1991	1,491,484.52	904,973	634,059-	2,274,692	11.21	202,916
1992	1,862,423.36	1,108,738	776,824-	2,825,490	11.47	246,337
1993	1,864,113.58	1,087,598	762,013-	2,812,538	11.74	239,569
1994	2,067,541.29	1,181,724	827,961-	3,102,256	12.01	258,306
1995	1,995,990.15	1,116,238	782,079-	2,977,668	12.29	242,284
1996	1,580,455.49	863,687	605,132-	2,343,633	12.58	186,298
1997	2,033,275.62	1,085,200	760,333-	2,996,936	12.87	232,862
1998	2,133,927.76	1,110,752	778,236-	3,125,557	13.17	237,324
1999	3,080,199.64	1,561,292	1,093,901-	4,482,121	13.48	332,502
2000	3,448,646.47	1,701,010	1,191,793-	4,985,304	13.79	361,516
2001	3,580,488.58	1,715,627	1,202,034-	5,140,571	14.11	364,321
2002	3,316,229.97	1,540,853	1,079,581-	4,727,434	14.44	327,385
2003	3,372,484.96	1,518,023	1,063,585-	4,773,318	14.77	323,177
2004	4,771,476.23	2,076,356	1,454,775-	6,703,399	15.11	443,640

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -10						
2005	4,722,991.94	1,982,523	1,389,032-	6,584,323	15.46	425,894
2006	4,687,645.11	1,893,434	1,326,613-	6,483,023	15.82	409,799
2007	4,681,341.77	1,814,675	1,271,431-	6,420,907	16.19	396,597
2008	4,939,196.89	1,834,220	1,285,125-	6,718,242	16.56	405,691
2009	3,292,886.53	1,166,340	817,183-	4,439,358	16.95	261,909
2010	4,591,014.12	1,545,335	1,082,721-	6,132,837	17.35	353,478
2011	5,806,847.25	1,847,274	1,294,271-	7,681,803	17.77	432,291
2012	11,907,667.26	3,557,535	2,492,546-	15,590,980	18.21	856,177
2013	13,507,412.66	3,750,198	2,627,533-	17,485,687	18.69	935,564
2014	13,165,205.54	3,365,553	2,358,036-	16,839,762	19.19	877,528
2015	15,943,422.37	3,696,961	2,590,233-	20,127,998	19.73	1,020,172
2016	27,700,672.26	5,728,499	4,013,606-	34,484,345	20.30	1,698,736
2017	43,395,153.79	7,809,392	5,471,560-	53,206,229	20.91	2,544,535
2018	51,665,601.87	7,820,105	5,479,066-	62,311,228	21.56	2,890,131
2019	52,312,050.07	6,352,775	4,450,998-	61,994,253	22.24	2,787,511
2020	47,210,793.27	4,237,641	2,969,054-	54,900,927	22.96	2,391,155
2021	63,845,993.02	3,567,714	2,499,677-	72,730,269	23.73	3,064,908
2022	58,899,464.05	1,166,209	817,090-	65,606,501	24.55	2,672,363
	477,048,046.87	87,077,964	61,010,169-	585,763,021		29,698,274

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7 6.23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -10						
1997	43,382.06	23,154	46,501-	94,221	12.87	7,321
1998	357,674.90	186,177	373,906-	767,348	13.17	58,265
1999	682,277.20	345,833	694,549-	1,445,054	13.48	107,200
2000	932,117.61	459,758	923,348-	1,948,677	13.79	141,311
2001	1,132,150.67	542,481	1,089,484-	2,334,850	14.11	165,475
2002	1,057,151.69	491,195	986,484-	2,149,351	14.44	148,847
2003	1,015,605.74	457,144	918,098-	2,035,264	14.77	137,797
2004	1,525,296.73	663,748	1,333,029-	3,010,855	15.11	199,262
2005	2,394,587.86	1,005,152	2,018,682-	4,652,729	15.46	300,953
2006	2,923,571.69	1,180,889	2,371,621-	5,587,550	15.82	353,195
2007	2,747,852.12	1,065,177	2,139,233-	5,161,870	16.19	318,831
2008	3,488,541.66	1,295,505	2,601,809-	6,439,205	16.56	388,841
2009	2,148,444.50	760,979	1,528,301-	3,891,590	16.95	229,592
2010	4,057,736.43	1,365,834	2,743,053-	7,206,563	17.35	415,364
2011	3,429,066.55	1,090,855	2,190,803-	5,962,776	17.77	335,553
2012	167,650.39	50,087	100,591-	285,006	18.21	15,651
2014	11,692,424.40	2,989,051	6,003,017-	18,864,684	19.19	983,048
2015	6,681,385.40	1,549,280	3,111,474-	10,460,998	19.73	530,208
2016	5,690,362.90	1,176,767	2,363,343-	8,622,742	20.30	424,766
2017	90,744.05	16,330	32,796-	132,614	20.91	6,342
2019	250,371.90	30,405	61,063-	336,472	22.24	15,129
2020	123,140.12	11,053	22,198-	157,653	22.96	6,866
	52,631,536.57	16,756,854	33,653,383-	91,548,074		5,289,817

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.3 10.05

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
1920	976.82	1,026	1,026			
1921	976.82	1,010	1,026			
1922	976.82	969	1,026			
1923	1,465.24	1,454	1,539			
1924	1,953.65	1,938	2,051			
1925	2,442.06	2,385	2,564			
1926	2,930.47	2,863	3,077			
1927	2,930.47	2,855	3,077			
1928	2,442.06	2,371	2,564			
1929	2,442.06	2,359	2,564			
1930	1,953.65	1,879	2,051			
1931	1,465.24	1,402	1,539			
1932	976.82	930	1,026			
1933	488.41	463	513			
1934	488.41	460	513			
1935	976.82	916	1,026			
1936	976.82	911	1,026			
1937	1,465.24	1,358	1,539			
1938	4,395.71	4,052	4,615			
1939	5,860.95	5,371	6,154			
1940	7,814.59	7,119	8,205			
1941	9,279.83	8,403	9,744			
1942	6,837.77	6,154	7,180			
1943	4,395.71	3,932	4,615			
1944	2,442.06	2,170	2,564			
1945	4,395.71	3,883	4,615			
1946	6,837.77	6,002	7,180			
1947	17,094.43	14,905	17,949			
1948	19,048.07	16,504	20,000			
1949	18,071.25	15,559	18,975			
1950	25,885.84	22,157	27,180			
1951	28,816.32	24,520	30,257			
1952	29,793.14	25,201	31,283			
1953	36,630.91	30,816	38,462			
1954	54,939.32	45,964	57,686			
1955	69,042.79	57,474	72,495			
1956	75,513.54	62,543	79,289			
1957	75,138.25	61,917	78,895			
1958	75,152.20	61,581	78,871	39	5.49	7
1959	99,193.54	80,865	103,570	583	5.59	104
1960	103,173.15	83,675	107,169	1,163	5.69	204

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
1961	52,519.59	42,352	54,243	903	5.80	156
1962	89,331.59	71,624	91,734	2,064	5.91	349
1963	88,636.00	70,657	90,496	2,572	6.02	427
1964	90,632.97	71,792	91,949	3,216	6.14	524
1965	79,390.81	62,487	80,032	3,328	6.26	532
1966	98,038.09	76,629	98,145	4,795	6.39	750
1967	87,704.87	68,073	87,186	4,904	6.52	752
1968	100,573.74	77,512	99,276	6,326	6.65	951
1969	113,016.48	86,437	110,706	7,961	6.79	1,172
1970	117,556.82	89,169	114,206	9,229	6.94	1,330
1971	95,573.26	71,892	92,078	8,274	7.09	1,167
1972	197,315.00	147,098	188,400	18,781	7.25	2,590
1973	110,362.62	81,534	104,427	11,454	7.41	1,546
1974	105,873.61	77,461	99,210	11,957	7.58	1,577
1975	30,975.93	22,442	28,743	3,782	7.75	488
1976	62,367.96	44,714	57,269	8,217	7.93	1,036
1977	92,945.74	65,934	84,447	13,146	8.11	1,621
1978	109,224.36	76,610	98,120	16,566	8.30	1,996
1979	264,573.97	183,461	234,972	42,831	8.49	5,045
1980	584,670.38	400,511	512,965	100,939	8.69	11,616
1981	487,792.80	330,050	422,720	89,462	8.89	10,063
1982	260,100.66	173,695	222,464	50,642	9.10	5,565
1983	382,972.07	252,371	323,231	78,890	9.31	8,474
1984	573,564.25	372,668	477,304	124,938	9.53	13,110
1985	744,902.48	477,110	611,071	171,077	9.75	17,546
1986	1,138,295.78	718,083	919,704	275,507	9.98	27,606
1987	1,330,211.59	825,742	1,057,591	339,131	10.22	33,183
1988	918,887.40	561,146	718,703	246,129	10.46	23,530
1989	1,033,289.65	620,594	794,842	290,112	10.70	27,113
1990	1,238,112.45	730,610	935,748	364,270	10.95	33,267
1991	993,578.95	575,461	737,037	306,221	11.21	27,317
1992	1,076,405.98	611,678	783,423	346,803	11.47	30,236
1993	1,219,951.77	679,416	870,180	410,769	11.74	34,989
1994	952,929.76	519,899	665,874	334,702	12.01	27,869
1995	1,130,336.21	603,396	772,815	414,038	12.29	33,689
1996	1,137,464.78	593,347	759,945	434,393	12.58	34,530
1997	1,099,912.32	560,361	717,697	437,211	12.87	33,971
1998	1,098,894.49	545,997	699,300	454,539	13.17	34,513
1999	1,404,869.58	679,732	870,585	604,528	13.48	44,846
2000	1,192,146.55	561,286	718,882	532,872	13.79	38,642
2001	1,341,560.40	613,603	785,888	622,750	14.11	44,135

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
2002	1,427,534.35	633,140	810,911	688,000	14.44	47,645
2003	643,597.16	276,528	354,170	321,607	14.77	21,774
2004	1,747,651.21	725,939	929,765	905,269	15.11	59,912
2005	2,018,328.05	808,704	1,035,769	1,083,475	15.46	70,082
2006	1,589,481.60	612,841	784,912	884,044	15.82	55,881
2007	1,494,564.83	553,019	708,294	860,999	16.19	53,181
2008	1,538,250.29	545,279	698,381	916,782	16.56	55,361
2009	1,144,465.44	386,944	495,589	706,100	16.95	41,658
2010	908,686.87	291,961	373,937	580,184	17.35	33,440
2011	1,591,465.16	483,264	618,952	1,052,086	17.77	59,206
2012	259,553.74	74,020	94,803	177,728	18.21	9,760
2016	0.23		0			
	38,499,123.37	19,564,589	25,035,791	15,388,288		1,128,034

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.6 2.93

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
1928	356.21	346	374			
1929	514.52	497	540			
1930	461.75	444	485			
1931	411.62	394	432			
1932	369.40	352	388			
1933	269.14	255	283			
1934	332.46	313	349			
1935	459.11	430	482			
1936	680.75	635	715			
1937	1,105.57	1,025	1,161			
1938	3,905.10	3,600	4,100			
1939	5,836.54	5,349	6,128			
1940	8,219.18	7,488	8,630			
1941	10,765.41	9,748	11,304			
1942	8,704.68	7,835	9,140			
1943	5,701.97	5,101	5,987			
1944	2,960.49	2,631	3,109			
1945	5,757.38	5,085	6,045			
1946	9,232.87	8,105	9,695			
1947	22,386.19	19,519	23,505			
1948	24,597.79	21,313	25,828			
1949	22,702.82	19,547	23,774	64	4.50	14
1950	32,460.76	27,785	33,793	291	4.62	63
1951	35,107.26	29,873	36,332	531	4.74	112
1952	35,880.36	30,350	36,913	761	4.86	157
1953	65,958.49	55,488	67,486	1,770	4.97	356
1954	68,233.61	57,087	69,431	2,214	5.08	436
1955	80,076.83	66,659	81,073	3,008	5.18	581
1956	85,868.27	71,120	86,498	3,664	5.28	694
1957	85,118.91	70,141	85,308	4,067	5.38	756
1958	85,558.68	70,108	85,267	4,570	5.49	832
1959	109,666.64	89,402	108,733	6,417	5.59	1,148
1960	108,590.10	88,069	107,112	6,908	5.69	1,214
1961	147,311.94	118,792	144,478	10,200	5.80	1,759
1962	178,095.38	142,793	173,669	13,331	5.91	2,256
1963	191,846.78	152,933	186,002	15,437	6.02	2,564
1964	221,372.50	175,354	213,271	19,170	6.14	3,122
1965	218,580.00	172,040	209,240	20,269	6.26	3,238
1966	233,914.55	182,832	222,366	23,244	6.39	3,638
1967	261,329.40	202,833	246,692	27,704	6.52	4,249
1968	299,817.49	231,069	281,033	33,775	6.65	5,079

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
1969	314,927.76	240,863	292,945	37,729	6.79	5,557
1970	276,092.25	209,421	254,704	35,193	6.94	5,071
1971	241,532.57	181,686	220,972	32,637	7.09	4,603
1972	335,064.09	249,790	303,802	48,015	7.25	6,623
1973	232,583.82	171,828	208,982	35,231	7.41	4,755
1974	181,732.22	132,963	161,714	29,105	7.58	3,840
1975	140,915.58	102,093	124,169	23,792	7.75	3,070
1976	140,171.94	100,495	122,225	24,956	7.93	3,147
1977	298,944.12	212,065	257,920	55,971	8.11	6,901
1978	395,530.23	277,425	337,413	77,894	8.30	9,385
1979	587,372.62	407,296	495,366	121,375	8.49	14,296
1980	633,042.92	433,647	527,415	137,280	8.69	15,797
1981	601,151.28	406,751	494,703	136,506	8.89	15,355
1982	715,504.94	477,814	581,132	170,148	9.10	18,698
1983	732,780.68	482,888	587,303	182,117	9.31	19,561
1984	963,910.42	626,291	761,714	250,392	9.53	26,274
1985	1,564,220.80	1,001,883	1,218,521	423,911	9.75	43,478
1986	2,019,625.12	1,274,060	1,549,551	571,055	9.98	57,220
1987	2,061,548.49	1,279,727	1,556,443	608,183	10.22	59,509
1988	2,029,718.42	1,239,508	1,507,527	623,677	10.46	59,625
1989	2,015,801.37	1,210,690	1,472,478	644,113	10.70	60,197
1990	2,094,198.36	1,235,786	1,503,001	695,907	10.95	63,553
1991	2,465,829.43	1,428,159	1,736,971	852,150	11.21	76,017
1992	2,889,414.81	1,641,939	1,996,976	1,036,910	11.47	90,402
1993	3,211,874.40	1,788,757	2,175,541	1,196,927	11.74	101,953
1994	3,566,609.76	1,945,871	2,366,628	1,378,312	12.01	114,764
1995	4,112,987.19	2,195,595	2,670,350	1,648,287	12.29	134,116
1996	2,376,406.40	1,239,629	1,507,675	987,552	12.58	78,502
1997	340,051.00	173,242	210,702	146,352	12.87	11,372
1998	464,855.63	230,968	280,910	207,188	13.17	15,732
1999	3,016,987.94	1,459,739	1,775,379	1,392,458	13.48	103,298
2000	2,400,703.70	1,130,299	1,374,704	1,146,035	13.79	83,106
2001	1,798,387.48	822,546	1,000,406	887,901	14.11	62,927
2002	5,471,140.36	2,426,560	2,951,256	2,793,441	14.44	193,452
2003	6,413,711.93	2,755,715	3,351,585	3,382,813	14.77	229,033
2004	4,914,496.07	2,041,383	2,482,792	2,677,429	15.11	177,196
2005	4,343,929.30	1,740,526	2,116,881	2,444,245	15.46	158,101
2006	4,496,388.31	1,733,627	2,108,490	2,612,718	15.82	165,153
2007	3,968,518.69	1,468,431	1,785,951	2,380,994	16.19	147,066
2008	4,805,350.02	1,703,400	2,071,727	2,973,891	16.56	179,583
2009	4,703,426.28	1,590,228	1,934,084	3,004,514	16.95	177,257

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -5						
2010	6,687,017.09	2,148,539	2,613,119	4,408,249	17.35	254,078
2011	3,658,123.49	1,110,826	1,351,020	2,490,010	17.77	140,124
2012	625,564.31	178,398	216,973	439,870	18.21	24,155
2016	123,725.00	24,423	29,704	100,207	20.30	4,936
2017	298,702.14	51,311	62,406	251,231	20.91	12,015
2018	135,546.61	19,584	23,819	118,505	21.56	5,497
2020	5,908,931.19	506,277	615,749	5,588,629	22.96	243,407
2021	5,960,584.57	317,938	386,686	5,871,928	23.73	247,447
2022	2,267,261.98	42,851	52,117	2,328,508	24.55	94,848
	112,683,413.98	48,026,471	58,407,752	59,909,833		3,864,320
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.5	3.43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R1.5						
NET SALVAGE PERCENT.. 0						
1927	2,615.56	2,616	2,616			
1941	2,615.56	2,616	2,616			
1942	2,615.56	2,616	2,616			
1947	2,615.56	2,616	2,616			
1948	2,615.56	2,616	2,616			
1949	2,615.56	2,616	2,616			
1950	2,615.56	2,616	2,616			
1951	2,615.56	2,616	2,616			
1952	2,615.56	2,616	2,616			
1953	5,231.12	5,188	4,183	1,048	0.29	1,048
1954	3,238.31	3,182	2,566	672	0.61	672
1955	3,238.31	3,151	2,541	697	0.94	697
1956	3,238.31	3,120	2,516	722	1.28	564
1957	5,713.64	5,449	4,394	1,320	1.62	815
1958	5,713.64	5,397	4,352	1,362	1.94	702
1959	3,238.31	3,031	2,444	794	2.24	354
1961	15,266.19	14,075	11,349	3,917	2.73	1,435
1962	46,082.07	42,185	34,014	12,068	2.96	4,077
1963	51,578.32	46,892	37,809	13,769	3.18	4,330
1964	68,982.82	62,262	50,202	18,781	3.41	5,508
1965	56,135.51	50,281	40,542	15,594	3.65	4,272
1966	57,646.14	51,223	41,301	16,345	3.90	4,191
1967	69,836.45	61,556	49,633	20,203	4.15	4,868
1968	60,926.17	53,232	42,921	18,005	4.42	4,074
1969	97,255.48	84,223	67,910	29,345	4.69	6,257
1970	144,480.88	123,965	99,954	44,527	4.97	8,959
1971	106,293.80	90,350	72,850	33,444	5.25	6,370
1972	44,951.01	37,836	30,507	14,444	5.54	2,607
1973	39,621.65	33,010	26,616	13,006	5.84	2,227
1974	8,117.50	6,693	5,397	2,720	6.14	443
1975	21,616.64	17,633	14,218	7,399	6.45	1,147
1976	18,925.82	15,265	12,308	6,618	6.77	978
1979	7,086.98	5,512	4,444	2,643	7.78	340
1980	357,462.34	274,327	221,192	136,270	8.14	16,741
1981	484,855.55	366,968	295,889	188,967	8.51	22,205
1982	424,586.61	316,742	255,391	169,196	8.89	19,032
1983	436,296.81	320,491	258,414	177,883	9.29	19,148
1984	407,054.32	294,243	237,250	169,804	9.70	17,506
1985	609,088.06	432,976	349,111	259,977	10.12	25,689
1986	624,874.78	436,344	351,827	273,048	10.56	25,857
1987	1,084,269.25	742,876	598,986	485,283	11.02	44,037

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R1.5						
NET SALVAGE PERCENT.. 0						
1988	1,036,930.55	696,517	561,606	475,325	11.49	41,369
1989	1,042,768.19	686,141	553,240	489,528	11.97	40,896
1990	983,684.49	633,208	510,560	473,124	12.47	37,941
1991	1,441,930.22	906,772	731,136	710,794	12.99	54,719
1992	1,480,849.88	908,812	732,781	748,069	13.52	55,331
1993	424,396.99	253,912	204,731	219,666	14.06	15,623
1994	2,593,915.39	1,510,411	1,217,854	1,376,061	14.62	94,122
1995	2,892,376.13	1,637,085	1,319,992	1,572,384	15.19	103,514
1996	1,917,821.50	1,053,152	849,163	1,068,658	15.78	67,722
1997	1,826,487.19	972,221	783,908	1,042,579	16.37	63,688
1998	2,381,240.54	1,225,315	987,979	1,393,262	16.99	82,005
1999	2,872,814.68	1,427,387	1,150,911	1,721,904	17.61	97,780
2000	1,642,032.11	785,827	633,617	1,008,415	18.25	55,256
2001	522,588.41	240,391	193,829	328,759	18.90	17,395
2002	814,404.24	359,266	289,678	524,726	19.56	26,826
2003	971,243.08	409,865	330,477	640,766	20.23	31,674
2004	1,333,537.50	536,842	432,859	900,678	20.91	43,074
2005	1,090,934.13	417,359	336,519	754,415	21.61	34,910
2006	1,174,217.79	425,736	343,274	830,944	22.31	37,245
2007	1,000,936.73	342,611	276,249	724,688	23.02	31,481
2008	674,249.98	216,913	174,898	499,352	23.74	21,034
2009	505,636.84	152,126	122,660	382,977	24.47	15,651
2010	220,977.00	61,809	49,837	171,140	25.21	6,789
2011	302,607.81	78,245	63,089	239,519	25.95	9,230
2012	4,897,157.98	1,161,312	936,373	3,960,785	26.70	148,344
2013	4,050,121.01	872,518	703,517	3,346,604	27.46	121,872
2014	6,633,286.64	1,284,934	1,036,051	5,597,236	28.22	198,343
2015	6,642,982.70	1,138,807	918,228	5,724,755	29.00	197,405
2016	10,189,824.91	1,519,710	1,225,352	8,964,473	29.78	301,023
2017	10,087,453.49	1,279,694	1,031,826	9,055,627	30.56	296,323
2018	10,330,005.29	1,077,316	868,647	9,461,358	31.35	301,798
2019	16,054,824.23	1,307,344	1,054,120	15,000,704	32.15	466,585
2020	15,309,617.88	892,398	719,546	14,590,072	32.96	442,660
2021	12,134,944.71	426,422	343,827	11,791,118	33.77	349,160
2022	12,739,212.32	149,176	120,281	12,618,931	34.59	364,814
	145,614,455.36	31,080,776	25,065,190	120,549,265		4,530,752

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.6 3.11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S4						
NET SALVAGE PERCENT.. 0						
1929	18.06	18	18			
1930	36.12	36	36			
1931	76.82	77	77			
1933	243.97	244	244			
1934	112.95	113	113			
1935	36.12	36	36			
1936	76.82	77	77			
1937	131.01	131	131			
1938	149.07	149	149			
1939	94.89	95	95			
1940	262.03	262	262			
1941	94.89	95	95			
1942	131.01	131	131			
1943	167.13	167	167			
1944	280.09	280	280			
1945	338.85	339	339			
1946	262.03	262	262			
1947	1,671.63	1,672	1,672			
1948	524.06	524	524			
1949	1,350.84	1,351	1,351			
1950	2,403.53	2,404	2,404			
1951	2,796.57	2,797	2,797			
1952	3,320.62	3,321	3,321			
1953	1,874.89	1,875	1,875			
1954	10,057.99	10,058	10,058			
1955	5,155.77	5,156	5,156			
1956	3,549.88	3,550	3,550			
1957	6,423.59	6,424	6,424			
1958	5,493.85	5,494	5,494			
1959	5,409.34	5,409	5,409			
1960	4,226.05	4,226	4,226			
1961	3,812.75	3,813	3,813			
1962	7,921.72	7,874	5,651	2,271	0.21	2,271
1963	5,333.85	5,255	3,771	1,563	0.52	1,563
1964	4,879.52	4,790	3,438	1,442	0.64	1,442
1965	6,400.62	6,267	4,498	1,903	0.73	1,903
1966	7,368.66	7,194	5,163	2,206	0.83	2,206
1967	13,156.83	12,811	9,194	3,963	0.92	3,963
1968	14,480.46	14,054	10,087	4,393	1.03	4,265
1969	18,391.96	17,793	12,770	5,622	1.14	4,932
1970	40,438.56	38,983	27,978	12,461	1.26	9,890

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S4						
NET SALVAGE PERCENT.. 0						
1971	3,913.88	3,761	2,699	1,215	1.37	887
1972	27,920.15	26,732	19,185	8,735	1.49	5,862
1973	36,510.46	34,820	24,990	11,520	1.62	7,111
1974	19,042.58	18,085	12,980	6,063	1.76	3,445
1975	8,590.31	8,122	5,829	2,761	1.91	1,446
1976	13,743.91	12,935	9,283	4,461	2.06	2,166
1977	16,917.40	15,840	11,368	5,549	2.23	2,488
1978	23,302.45	21,705	15,578	7,724	2.40	3,218
1979	27,158.83	25,149	18,049	9,110	2.59	3,517
1980	21,519.71	19,804	14,213	7,307	2.79	2,619
1981	21,974.74	20,091	14,419	7,556	3.00	2,519
1982	19,301.47	17,520	12,574	6,727	3.23	2,083
1983	31,061.86	27,973	20,076	10,986	3.48	3,157
1984	346,651.35	309,411	222,064	124,587	3.76	33,135
1985	39,511.45	34,940	25,076	14,435	4.05	3,564
1986	37,109.14	32,476	23,308	13,801	4.37	3,158
1987	66,641.15	57,673	41,392	25,249	4.71	5,361
1988	52,454.95	44,826	32,172	20,283	5.09	3,985
1989	15,094.73	12,723	9,131	5,964	5.50	1,084
1990	190,883.64	158,489	113,747	77,137	5.94	12,986
1991	35,328.02	28,848	20,704	14,624	6.42	2,278
1992	22,981.93	18,418	13,219	9,763	6.95	1,405
1993	28,299.85	22,219	15,947	12,353	7.52	1,643
1994	86,609.81	66,491	47,720	38,890	8.13	4,784
1995	35,328.02	26,445	18,980	16,348	8.80	1,858
1996	22,981.93	16,744	12,017	10,965	9.50	1,154
1997	68,945.80	48,735	34,977	33,969	10.26	3,311
1998	22,981.93	15,720	11,282	11,700	11.06	1,058
2021	7,991,283.53	342,506	245,816	7,745,468	33.50	231,208
2022	19,976,886.45	285,470	204,882	19,772,005	34.50	573,102
	29,489,886.83	1,950,278	1,416,813	28,073,074		958,027

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.3 3.25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2003	8,589,887.39	2,606,601	2,576,637	6,013,250	38.31	156,963
2004	151,590.00	43,796	43,293	108,297	39.11	2,769
2007	304,873.48	74,557	73,700	231,173	41.55	5,564
2010	5,302.35	1,056	1,044	4,258	44.05	97
2011	2,433,934.29	447,406	442,263	1,991,671	44.89	44,368
2012	333,910.38	56,157	55,511	278,399	45.75	6,085
2013	809,106.07	123,575	122,154	686,952	46.60	14,741
2015	211,327.04	25,628	25,333	185,994	48.33	3,848
2016	777,617.61	82,000	81,057	696,561	49.20	14,158
2017	2,166,774.12	193,818	191,590	1,975,184	50.08	39,441
2018	7,347,918.65	538,382	532,194	6,815,725	50.97	133,720
2019	76,269.31	4,368	4,317	71,952	51.85	1,388
2021	34,640.51	850	841	33,800	53.65	630
2022	19,780.52	162	160	19,621	54.55	360
	23,262,931.72	4,198,356	4,150,094	19,112,838		424,132

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 1.82

APPENDIX

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

TABLE A-1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND NET SALVAGE NORMALIZATION RELATED TO ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)	(10)	(11)=(10)/(4)	(12)=(7)+(10)	(13)=(12)/(4)
	ELECTRIC PLANT												
	DISTRIBUTION PLANT												
360.30	SIDEWALKS AND CURBS ON PUBLIC PROPERTY		65-S2.5	1,218,246.29	667,958	550,288	11,797	0.97	46.6	0	-	11,797	0.97
361.00	STRUCTURES AND IMPROVEMENTS		70-S1.5	241,611,849.94	79,369,016	162,242,834	3,089,558	1.28	52.5	2,629,018	1.09	5,718,576	2.37
362.00	STATION EQUIPMENT		45-S0	1,563,499,955.95	285,690,218	1,277,809,737	36,827,729	2.36	34.7	5,653,412	0.36	42,481,141	2.72
364.00	POLES, TOWERS AND FIXTURES		65-R2.5	1,024,137,859.55	204,387,268	819,750,591	17,495,526	1.71	46.9	19,230,031	1.88	36,725,557	3.59
365.00	OVERHEAD CONDUCTORS AND DEVICES		60-R1	2,855,533,126.70	614,064,997	2,241,468,130	42,871,530	1.50	52.3	3,568,007	0.12	46,439,537	1.63
366.00	UNDERGROUND CONDUIT		75-R4	509,797,650.33	259,019,228	250,778,423	4,695,962	0.92	53.4	605,507	0.12	5,301,469	1.04
367.00	UNDERGROUND CONDUCTORS AND DEVICES		58-R2	1,461,353,642.60	514,409,209	946,944,434	21,679,761	1.48	43.7	3,859,918	0.26	25,539,679	1.75
368.00	LINE TRANSFORMERS		55-R2	1,582,143,710.59	380,605,551	1,201,538,160	33,973,819	2.15	35.4	13,788,507	0.87	47,762,326	3.02
369.00	SERVICES		65-R4	535,118,075.54	240,771,597	294,346,478	6,629,578	1.24	44.4	2,785,830	0.52	9,415,408	1.76
370.00	METERS		20-L0.5	365,421,420.67	82,051,298	283,370,123	21,728,635	5.95	13.0	5,132,407	1.40	26,861,042	7.35
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		38-R1	498,983,988.92	118,928,854	380,055,135	13,344,137	2.67	28.5	2,948,201	0.59	16,292,338	3.27
	TOTAL DISTRIBUTION PLANT			**10,638,819,527.08**	**2,779,965,195**	**7,858,854,333**	**202,348,032**	**1.90**		**60,200,838**	**0.57**	**262,548,870**	**2.47**
	GENERAL PLANT - STRUCTURES AND IMPROVEMENTS												
390.00	STRUCTURES AND IMPROVEMENTS - DISTRIBUTION		55-R2	34,060,708.63	4,986,725	29,073,984	612,821	1.80	47.4	37,654	0.11	650,475	1.91
	TOTAL STRUCTURES AND IMPROVEMENTS			**34,060,708.63**	**4,986,725**	**29,073,984**	**612,821**	**1.80**		**37,654**	**0.11**	**650,475**	**1.91**
	GENERAL PLANT - AMORTIZED												
391.10	OFFICE FURNITURE		20-SQ	14,686,628.83	14,680,431		734,331	5.00 *		0	-	734,331	5.00
391.20	OFFICE EQUIPMENT		4-SQ	272,720.08	86,133		68,180	25.00 *		0	-	68,180	25.00
391.31	OFFICE COMPUTER EQUIPMENT		7-SQ	13,045,730.89	1,618,653		1,864,235	14.29 *		0	-	1,864,235	14.29
392.10	TRANSPORTATION EQUIPMENT 13,000 LBS AND UNDER		9-SQ	13,641,107.47	12,292,678		1,515,527	11.11 *		(254,738)	(1.87)	1,260,789	9.24
392.20	TRANSPORTATION EQUIPMENT OVER 13,000 LBS		13-SQ	161,495,690.14	79,917,974		12,419,019	7.69 *		(180,247)	(0.11)	12,238,772	7.58
393.00	STORES EQUIPMENT		7-SQ	613,067.36	191,456		87,607	14.29 *		0	-	87,607	14.29
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		7-SQ	18,295,904.22	9,931,068		2,614,485	14.29 *		0	-	2,614,485	14.29
395.00	LABORATORY EQUIPMENT		5-SQ	2,933,338.47	1,864,760		586,668	20.00 *		0	-	586,668	20.00
396.00	POWER OPERATED EQUIPMENT		13-SQ	30,192,786.24	14,592,657		2,321,825	7.69 *		0	-	2,321,825	7.69
397.00	COMMUNICATION EQUIPMENT		10-SQ	66,943,612.98	15,601,419		6,694,361	10.00 *		0	-	6,694,361	10.00
398.00	MISCELLANEOUS EQUIPMENT		7-SQ	1,738,564.62	1,185,708		248,441	14.29 *		0	-	248,441	14.29
	TOTAL GENERAL PLANT - AMORTIZED			**323,859,151.30**	**151,962,938**		**29,154,679**	**9.00**		**(434,985)**	**(0.13)**	**28,719,694**	**8.87**
	TOTAL DEPRECIABLE ELECTRIC PLANT			**10,996,739,387.01**	**2,936,914,858**	**7,887,928,317**	**232,115,532**	**2.11**		**59,803,507**	**0.54**	**291,919,039**	**2.65**
	COMMON PLANT												
	GENERAL PLANT												
390.00	STRUCTURES AND IMPROVEMENTS												
	PARK PLAZA	06-2041	55-R2	42,042,347.28	15,469,678	26,572,669	1,506,683	3.58	17.6				
	LEASEHOLD IMPROVEMENTS		55-R2	29,397,940.70	12,908,055	16,489,885	317,645	1.08	51.9				
	TOTAL COMMON PLANT			**71,440,287.98**	**28,377,734**	**43,062,554**	**1,824,328**	**2.55**		**(203,779)**	**(0.29)**	**1,620,549**	**2.27**
	TOTAL DEPRECIABLE PLANT			**11,068,179,674.99**	**2,965,292,592**	**7,930,990,871**	**233,939,860**	**2.11**		**59,599,728**	**0.54**	**293,539,588**	**2.65**
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED												
	ELECTRIC PLANT												
303.00	MISCELLANEOUS INTANGIBLE PLANT			42,442,867.56	16,035,584								
360.00	LAND AND LAND RIGHTS			50,095,922.23	(65)								
389.10	LAND AND LAND RIGHTS			155,022.78	(15,561)								
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**92,693,812.57**	**16,019,959**								
	TOTAL ELECTRIC AND COMMON PLANT			**11,160,873,487.56**	**2,981,312,551**								

* ACCRUAL RATE FOR GENERAL PLANT AMORTIZATION ACCOUNTS IS EQUAL TO 1 DIVIDED BY THE AMORTIZATION PERIOD.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

TABLE A-2. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND NET SALVAGE NORMALIZATION RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)	(9)	(10)=(9)/(3)	(11)=(6)+(9)	(12)=(11)/(3)
	GAS PLANT											
	PRODUCTION PLANT											
304.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	55-R3	41,238.98	71,265	(30,026)	0	-	-	0	-	0	-
305.00	STRUCTURES AND IMPROVEMENTS	38-R1.5	8,358,112.00	10,082,718	(1,724,606)	0	-	-	27,494	0.33	27,494	0.33
307.00	OTHER POWER EQUIPMENT	28-R2	2,877,909.07	2,981,926	(104,017)	0	-	-	0	-	0	-
311.00	LIQUEFIED PETROLEUM GAS EQUIPMENT	50-S3	39,380,160.50	42,370,650	(2,990,490)	0	-	-	0	-	0	-
320.00	OTHER EQUIPMENT	21-R1	227,575.42	579,466	(351,890)	0	-	-	0	-	0	-
	TOTAL PRODUCTION PLANT		**50,884,995.97**	**56,086,024**	**(5,201,029)**	**0**	**0.00**		**27,494**	**0.05**	**27,494**	**0.05**
	OTHER STORAGE PLANT											
361.00	STRUCTURES AND IMPROVEMENTS	45-R3	293,633.92	(82,706)	376,340	8,537	2.91	44.1	16,788	5.72	25,325	8.62
362.00	GAS HOLDERS	55-R3	5,066,482.48	5,066,483	0	0	-	-	0	-	0	-
363.20	VAPORIZING EQUIPMENT	55-S2.5	8,763,433.13	1,360,102	7,403,331	146,146	1.67	50.7	(1,995)	(0.02)	144,151	1.64
363.40	MEASURING AND REGULATING STATION EQUIPMENT	55-S2.5	5,428,187.16	3,271,993	2,156,194	41,316	0.76	52.2	181,979	3.35	223,295	4.11
	TOTAL OTHER STORAGE PLANT		**19,551,736.69**	**9,615,871**	**9,935,865**	**195,999**	**1.00**		**196,772**	**1.01**	**392,771**	**2.01**
	TRANSMISSION PLANT											
367.00	MAINS	70-S2.5	93,786,846.70	50,016,287	43,770,560	895,891	0.96	48.9	25,699	0.03	921,590	0.98
369.00	MEASURING AND REGULATING STATION EQUIPMENT	30-S2.5	4,336,420.46	413,497	3,922,923	599,520	13.83	6.5	562,685	12.98	1,162,205	26.80
	TOTAL TRANSMISSION PLANT		**98,123,267.16**	**50,429,784**	**47,693,483**	**1,495,411**	**1.52**		**588,384**	**0.60**	**2,083,795**	**2.12**
	DISTRIBUTION PLANT											
374.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	55-R3	54,865.26	29,301	25,565	818	1.49	31.3	0	-	818	1.49
375.00	STRUCTURES AND IMPROVEMENTS	60-S2.5	103,089,212.29	40,268,316	62,820,896	1,302,579	1.26	48.2	162,782	0.16	1,465,361	1.42
376.00	MAINS	75-R2.5	3,768,890,222.03	1,056,277,834	2,712,612,388	44,221,020	1.17	61.3	12,977,365	0.34	57,198,385	1.52
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	55-R4	155,052,903.89	38,926,764	116,126,140	2,680,402	1.73	43.3	223,281	0.14	2,903,683	1.87
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	55-R3	102,610,302.42	56,393,875	46,216,427	1,253,723	1.22	36.9	0	-	1,253,723	1.22
380.00	SERVICES	65-R3	5,364,802,876.79	1,132,262,180	4,232,540,696	76,282,009	1.42	55.5	12,753,330	0.24	89,035,339	1.66
381.00	METERS	25-L0.5	477,048,046.87	(61,010,169)	538,058,216	27,324,581	5.73	19.7	7,180,258	1.51	34,504,839	7.23
382.00	METER INSTALLATIONS	25-L0.5	52,631,536.57	(33,653,383)	86,284,920	4,989,417	9.48	17.3	611,219	1.16	5,600,636	10.64
383.00	HOUSE REGULATORS	25-L0.5	38,499,123.37	25,035,791	13,463,332	972,538	2.53	13.8	0	-	972,538	2.53
384.00	HOUSE REGULATOR INSTALLATIONS	25-L0.5	112,683,413.98	58,407,752	54,275,662	3,449,649	3.06	15.7	0	-	3,449,649	3.06
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	35-R1.5	145,614,455.36	25,065,190	120,549,265	4,530,752	3.11	26.6	0	-	4,530,752	3.11
387.00	OTHER EQUIPMENT	35-S4	29,489,886.83	1,416,813	28,073,074	958,027	3.25	29.3	0	-	958,027	3.25
	TOTAL DISTRIBUTION PLANT		**10,350,466,845.66**	**2,339,420,263**	**8,011,046,581**	**167,965,515**	**1.62**		**33,908,235**	**0.33**	**201,873,750**	**1.95**
	GENERAL PLANT											
390.00	STRUCTURES AND IMPROVEMENTS	55-R2	23,262,931.72	4,150,094	19,112,838	424,132	1.82	45.1	0	-	424,132	1.82
	TOTAL STRUCTURES AND IMPROVEMENTS		23,262,931.72	4,150,094	19,112,838	424,132	1.82	45.1	0	-	424,132	1.82
	GENERAL PLANT - AMORTIZED											
391.10	OFFICE FURNITURE	20-SQ	12,819,389.03	10,350,997		640,969	5.00 *		0	-	640,969	5.00
391.20	OFFICE EQUIPMENT	4-SQ	0.00	(57,538)		0	25.00 *		0	-	0	-
391.30	OFFICE COMPUTER EQUIPMENT	7-SQ	1,569,512.98	10,144		224,283	14.29 *		0	-	224,283	14.29
391.33	PERSONAL COMPUTING EQUIPMENT	3-SQ	2,516,592.30	1,011,275		838,780	33.33 *		0	-	838,780	33.33
392.10	CARS AND LIGHT TRUCKS	9-SQ	26,749,925.73	21,429,670		2,971,917	11.11 *		0	-	2,971,917	11.11
392.20	HEAVY TRUCKS AND TRUCK MOUNTED EQUIPMENT	13-SQ	59,281,268.33	24,732,973		4,558,730	7.69 *		0	-	4,558,730	7.69
393.00	STORES EQUIPMENT	7-SQ	2,362,541.81	1,610,134		337,607	14.29 *		0	-	337,607	14.29
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	7-SQ	40,310,338.31	17,310,356		5,760,347	14.29 *		0	-	5,760,347	14.29
395.00	LABORATORY EQUIPMENT	5-SQ	824,357.78	155,951		164,872	20.00 *		0	-	164,872	20.00
396.00	POWER OPERATED EQUIPMENT	13-SQ	22,244,566.40	10,557,559		1,710,607	7.69 *		0	-	1,710,607	7.69
397.00	COMMUNICATION EQUIPMENT	10-SQ	6,278,285.39	2,674,354		627,829	10.00 *		0	-	627,829	10.00
398.00	MISCELLANEOUS EQUIPMENT	7-SQ	1,411,781.32	1,037,977		201,744	14.29 *		0	-	201,744	14.29
	TOTAL GENERAL PLANT - AMORTIZED		**176,368,559.37**	**90,823,851**		**18,037,685**	**10.23**		**0**	**-**	**18,037,685**	**10.23**
	TOTAL GENERAL PLANT		**199,631,491.09**	**94,973,945**		**18,461,817**	**9.25**		**0**	**-**	**18,461,817**	**9.25**
	TOTAL DEPRECIABLE PLANT		**10,718,658,336.57**	**2,550,525,888**	**8,082,587,738**	**188,118,742**	**1.76**		**34,720,885**	**0.32**	**222,839,627**	**2.08**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

TABLE A-2. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND NET SALVAGE NORMALIZATION RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)	(9)	(10)=(9)/(3)	(11)=(6)+(9)	(12)=(11)/(3)
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED											
303.00	MISCELLANEOUS INTANGIBLE PLANT		6,228,071.00	1,800,411								
304.00	LAND AND LAND RIGHTS		1,220,370.86									
360.00	LAND		23,496.57									
365.00	LAND AND LAND RIGHTS		5,421,127.53									
374.00	LAND AND LAND RIGHTS		7,185,318.39									
388.00	ARC - DISTRIBUTION PLANT		10,834,324.00									
399.00	ARC - GENERAL PLANT		4,785,231.71									
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED		35,697,940.06	1,800,411								
	TOTAL GAS PLANT		10,754,356,276.63	2,552,326,299								

* ACCRUAL RATE FOR GENERAL PLANT AMORTIZATION ACCOUNTS IS EQUAL TO 1 DIVIDED BY THE AMORTIZATION PERIOD.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

TABLE A-3. CALCULATION OF NET SALVAGE NORMALIZATION RELATED
TO ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	2018		2019		2020		2021		2022			
ACCOUNT	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=-(12)/5
ELECTRIC PLANT												
361.00	7,762,683.00	39,421.00	1,556,168.00	111,272.00	1,290,301.00	98,724.00	2,344,276.00	252,887.00	1,036,067.00	342,101.00	(13,145,090.00)	2,629,018
362.00	11,919,718.00	2,363,270.00	6,656,960.00	13,049,045.00	12,000,961.00	180,956.00	4,561,605.00	543,749.00	9,745,262.00	480,428.00	(28,267,058.00)	5,653,412
364.00	29,164,045.00	13,109.00	15,588,295.00	769,589.00	19,332,427.00	507,357.00	17,777,026.00	1,963,822.00	19,434,433.00	1,892,194.00	(96,150,155.00)	19,230,031
365.00	7,022,027.00	627,990.00	3,042,692.00	638,655.00	3,501,308.00	642,190.00	3,723,143.00	1,172,499.00	4,691,230.00	1,059,029.00	(17,840,037.00)	3,568,007
366.00	2,401,610.00		282,859.00	35,206.00	106,041.00	23,337.00	115,849.00	91,749.00	360,687.00	89,220.00	(3,027,534.00)	605,507
367.00	3,692,718.00		4,113,293.00	158,429.00	3,209,537.00	105,017.00	3,808,834.00	412,869.00	5,553,014.00	401,490.00	(19,299,591.00)	3,859,918
368.00	13,629,151.00		13,931,465.00	4,452.00	15,994,886.00	9,214.00	12,970,138.00		12,430,563.00		(68,942,537.00)	13,788,507
369.00	2,786,064.00		2,308,140.00	88,016.00	2,585,307.00	58,343.00	3,657,641.00	229,372.00	3,190,778.00	223,050.00	(13,929,149.00)	2,785,830
370.00	3,787,282.00		3,892,480.00	158,429.00	3,640,789.00	105,017.00	5,392,467.00	412,869.00	9,959,151.00	333,817.00	(25,662,037.00)	5,132,407
373.00	3,014,074.00		2,558,906.00	105,619.00	2,762,877.00	70,011.00	3,044,657.00	275,246.00	4,079,026.00	267,660.00	(14,741,004.00)	2,948,201
390.00	176,698.00		4,026.00	(2,013.00)			5,531.00				(188,268.00)	37,654
392.10		497,985.23		591,553.19		23,316.98		157,439.26		3,397.76	1,273,692.42	(254,738)
392.20				206,363.87		188,655.56		467,143.20		39,074.27	901,236.90	(180,247)
TOTAL ELECTRIC PLANT	**85,356,070.00**	**3,541,775.23**	**53,935,284.00**	**15,914,616.06**	**64,424,434.00**	**2,012,138.54**	**57,401,167.00**	**5,979,644.46**	**70,480,211.00**	**5,131,461.03**	**(299,017,530.68)**	**59,803,507**
COMMON PLANT												
390.00	42,942.00	443.00	256.00	235,563.00	(119.00)		656,929.00		164,525.00	1,647,420.00	1,018,893.00	(203,779)
TOTAL COMMON PLANT	**42,942.00**	**443.00**	**256.00**	**235,563.00**	**(119.00)**	**-**	**656,929.00**	**-**	**164,525.00**	**1,647,420.00**	**1,018,893.00**	**(203,779)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

TABLE A-4. CALCULATION OF NET SALVAGE NORMALIZATION
RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	2018		2019		2020		2021		2022			
ACCOUNT	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=-(12)/5
GAS PLANT												
305.00	54,749.00						82,719.00				(137,468.00)	27,494
361.00		(2,833.00)					74,524.00	1,926.00	8,509.00		(83,940.00)	16,788
363.20		18,448.00		(6,364.00)		(3,380.00)		1,270.00			9,974.00	(1,995)
363.40			909,897.00								(909,897.00)	181,979
367.00							138,542.00		(10,047.00)		(128,495.00)	25,699
369.00	231,809.00	6,855.00	1,576,502.00	14,244.00	710,521.00	1,419.00	5,573.00	18,494.00	353,533.00	23,500.00	(2,813,426.00)	562,685
375.00	131,315.00		17,810.00		4,101.00		525,832.00		135,844.00	991.00	(813,911.00)	162,782
376.00	15,025,784.00	195,572.00	23,799,061.00	271,473.00	5,632,222.00	55,388.00	17,376,940.00	45,935.00	3,743,510.00	122,325.00	(64,886,824.00)	12,977,365
378.00	540.00			8,778.00	103,500.00	3,629.00	1,024,774.00				(1,116,407.00)	223,281
380.00	12,843,048.00		14,871,303.00	332,578.00	11,526,875.00	14,500.00	11,824,515.00	72,391.00	13,315,191.00	194,814.00	(63,766,649.00)	12,753,330
381.00	9,289,330.00		7,794,086.00	205,882.00	4,651,756.00	8,976.00	8,833,326.00	45,455.00	5,715,429.00	122,325.00	(35,901,289.00)	7,180,258
382.00	600,169.00		589,197.00	15,837.00	626,883.00	690.00	649,937.00	3,367.00	618,863.00	9,061.00	(3,056,094.00)	611,219
TOTAL GAS PLANT	**38,176,744.00**	**218,042.00**	**49,557,856.00**	**842,428.00**	**23,255,858.00**	**81,222.00**	**40,536,682.00**	**188,838.00**	**23,880,832.00**	**473,016.00**	**(173,604,426.00)**	**34,720,885**

ELECTRIC PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. 0						
1943	4,509.42	3,811	4,509			
1950	2,483.58	2,022	2,484			
1951	1,034.98	838	1,035			
1952	26.09	21	26			
1953	1,772.46	1,417	1,772			
1954	16,470.26	13,077	16,470			
1955	2,220.19	1,751	2,220			
1957	5,499.13	4,275	5,499			
1958	660.43	510	660			
1959	1,684.56	1,290	1,685			
1961	8,359.44	6,295	8,359			
1963	3,075.36	2,275	3,075			
1965	6,197.58	4,499	6,198			
1966	6,758.94	4,857	6,759			
1967	3,837.83	2,730	3,838			
1968	28,455.42	20,020	28,455			
1970	10,590.38	7,283	10,590			
1973	4,027.48	2,667	4,027			
1974	5,398.40	3,526	5,398			
1975	15,540.70	10,006	15,541			
1976	11,465.04	7,274	11,316	149	23.76	6
1977	18,158.31	11,345	17,649	509	24.39	21
1978	1,317.99	810	1,260	58	25.03	2
1979	972.02	588	915	57	25.69	2
1980	7,905.22	4,698	7,308	597	26.37	23
1981	9,998.65	5,836	9,079	920	27.06	34
1983	9,177.78	5,157	8,023	1,155	28.48	41
1984	3,883.90	2,138	3,326	558	29.22	19
1985	31,697.92	17,083	26,575	5,123	29.97	171
1986	37,044.68	19,526	30,376	6,669	30.74	217
1987	9,851.44	5,074	7,893	1,958	31.52	62
1988	10,689.33	5,376	8,363	2,326	32.31	72
1989	3,782.78	1,855	2,886	897	33.13	27
1990	1,099.83	525	817	283	33.95	8
1991	3,344.00	1,554	2,417	927	34.79	27
1992	62,340.83	28,159	43,806	18,535	35.64	520
1998	303,656.40	112,213	174,565	129,091	40.98	3,150

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 360.30 SIDEWALKS AND CURBS ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. 0						
2003	9,251.85	2,749	4,277	4,975	45.69	109
2008	1,524.03	339	527	997	50.56	20
2009	552,481.66	114,408	177,980	374,501	51.54	7,266
	1,218,246.29	439,877	667,958	550,288		11,797

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.6 0.97

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S1.5						
NET SALVAGE PERCENT.. 0						
1925	2,518.73	2,122	2,519			
1928	10,894.00	9,045	10,894			
1938	60,313.28	47,458	58,482	1,831	14.92	123
1943	2,049,152.86	1,563,504	1,926,683	122,470	16.59	7,382
1945	10,093.64	7,601	9,367	727	17.29	42
1950	21,994.82	15,984	19,697	2,298	19.13	120
1951	96,272.20	69,426	85,553	10,719	19.52	549
1952	70,857.00	50,703	62,481	8,376	19.91	421
1953	121,328.41	86,126	106,132	15,196	20.31	748
1954	214,160.36	150,799	185,827	28,333	20.71	1,368
1955	202,617.55	141,486	174,351	28,267	21.12	1,338
1956	237,647.62	164,521	202,737	34,911	21.54	1,621
1957	280,325.65	192,385	237,073	43,253	21.96	1,970
1958	36,582.17	24,881	30,660	5,922	22.39	264
1959	37,264.52	25,111	30,944	6,321	22.83	277
1960	8,247.65	5,506	6,785	1,463	23.27	63
1961	257,494.97	170,240	209,784	47,711	23.72	2,011
1962	183,102.43	119,853	147,693	35,409	24.18	1,464
1963	52,016.80	33,700	41,528	10,489	24.65	426
1964	65,637.81	42,083	51,858	13,780	25.12	549
1965	69,980.68	44,378	54,686	15,295	25.61	597
1966	45,868.88	28,766	35,448	10,421	26.10	399
1967	256,525.24	159,046	195,990	60,535	26.60	2,276
1968	217,888.21	133,535	164,553	53,335	27.10	1,968
1969	219,827.90	133,090	164,005	55,823	27.62	2,021
1970	85,081.63	50,867	62,683	22,399	28.15	796
1971	225,971.19	133,389	164,373	61,598	28.68	2,148
1972	253,373.41	147,572	181,851	71,522	29.23	2,447
1973	315,902.97	181,508	223,670	92,233	29.78	3,097
1974	583,589.21	330,644	407,448	176,141	30.34	5,806
1975	1,689,273.10	943,104	1,162,173	527,100	30.92	17,047
1976	833,441.46	458,393	564,871	268,570	31.50	8,526
1977	1,743,431.86	944,190	1,163,511	579,921	32.09	18,072
1978	1,531,681.77	816,172	1,005,757	525,925	32.70	16,083
1979	316,029.77	165,644	204,121	111,909	33.31	3,360
1980	897,036.92	462,100	569,439	327,598	33.94	9,652
1981	785,200.71	397,421	489,736	295,465	34.57	8,547
1982	2,487,987.98	1,236,182	1,523,329	964,659	35.22	27,390
1983	1,967,817.79	959,449	1,182,315	785,503	35.87	21,899
1984	705,798.39	337,372	415,739	290,059	36.54	7,938
1985	1,889,556.17	884,860	1,090,400	799,156	37.22	21,471

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S1.5						
NET SALVAGE PERCENT.. 0						
1986	3,801,552.26	1,742,746	2,147,560	1,653,992	37.91	43,629
1987	1,539,225.88	690,235	850,566	688,660	38.61	17,836
1988	11,872,503.83	5,203,600	6,412,319	5,460,185	39.32	138,865
1989	9,351,324.77	4,001,058	4,930,444	4,420,881	40.05	110,384
1990	3,790,264.99	1,582,170	1,949,685	1,840,580	40.78	45,134
1991	1,847,920.54	751,568	926,146	921,775	41.53	22,195
1992	4,223,261.65	1,671,820	2,060,159	2,163,103	42.29	51,149
1993	5,436,649.42	2,092,349	2,578,371	2,858,278	43.06	66,379
1994	6,029,141.08	2,253,150	2,776,523	3,252,618	43.84	74,193
1995	17,357,079.44	6,290,726	7,751,968	9,605,111	44.63	215,216
1996	875,185.75	307,190	378,546	496,640	45.43	10,932
1997	1,671,663.80	567,179	698,926	972,738	46.25	21,032
1998	6,108,393.64	2,000,927	2,465,713	3,642,681	47.07	77,389
1999	4,885,868.49	1,541,834	1,899,979	2,985,889	47.91	62,323
2000	3,201,868.51	971,991	1,197,770	2,004,099	48.75	41,110
2001	4,238,200.03	1,234,545	1,521,311	2,716,889	49.61	54,765
2002	20,036,055.52	5,587,254	6,885,090	13,150,966	50.48	260,518
2003	10,751,809.28	2,863,099	3,528,155	7,223,654	51.36	140,647
2004	492,935.67	125,063	154,113	338,823	52.24	6,486
2005	3,225,992.99	777,013	957,502	2,268,491	53.14	42,689
2006	6,090,838.02	1,387,858	1,710,237	4,380,601	54.05	81,047
2007	6,390,672.70	1,373,100	1,692,051	4,698,622	54.96	85,492
2008	8,822,882.88	1,778,429	2,191,532	6,631,351	55.89	118,650
2009	4,535,365.32	853,964	1,052,327	3,483,038	56.82	61,300
2010	452,950.41	79,203	97,601	355,349	57.76	6,152
2011	88,561.92	14,284	17,602	70,960	58.71	1,209
2012	5,174,986.96	764,397	941,955	4,233,032	59.66	70,953
2013	86,866.27	11,640	14,344	72,522	60.62	1,196
2014	1,341,616.91	161,182	198,622	1,142,995	61.59	18,558
2015	1,639,889.12	174,304	214,792	1,425,097	62.56	22,780
2016	4,313,338.41	398,078	490,546	3,822,792	63.54	60,164
2017	10,378,104.31	810,945	999,315	9,378,789	64.53	145,340
2018	25,992,493.44	1,663,520	2,049,931	23,942,562	65.52	365,424
2019	10,041,771.19	500,683	616,984	9,424,787	66.51	141,705
2020	1,636,215.38	58,429	72,001	1,564,214	67.50	23,174
2021	11,301,694.20	242,195	298,453	11,003,241	68.50	160,631
2022	1,446,917.25	10,331	12,731	1,434,186	69.50	20,636
	241,611,849.94	64,408,275	79,369,016	162,242,834		3,089,558

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.5 1.28

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. 0						
1925	16,223.47	16,223	16,223			
1926	16,542.42	16,542	16,542			
1928	67,166.67	67,167	67,167			
1929	22,323.62	22,324	22,324			
1930	6,982.94	6,983	6,983			
1931	74,527.10	74,527	74,527			
1937	25,489.07	24,554	21,000	4,489	1.65	2,721
1938	133,891.97	127,882	109,370	24,522	2.02	12,140
1939	10,842.00	10,266	8,780	2,062	2.39	863
1940	78,894.00	74,055	63,335	15,559	2.76	5,637
1941	5,488.21	5,106	4,367	1,121	3.13	358
1942	59,769.52	55,107	47,130	12,640	3.51	3,601
1943	1,821,272.94	1,664,243	1,423,333	397,940	3.88	102,562
1944	9,781.44	8,855	7,573	2,208	4.26	518
1945	12,452.13	11,168	9,551	2,901	4.64	625
1946	10,076.00	8,952	7,656	2,420	5.02	482
1947	13,007.07	11,446	9,789	3,218	5.40	596
1948	45,634.00	39,773	34,016	11,618	5.78	2,010
1949	13,594.00	11,733	10,035	3,559	6.16	578
1950	140,148.00	119,748	102,414	37,734	6.55	5,761
1951	187,555.00	158,672	135,703	51,852	6.93	7,482
1952	1,480,780.00	1,239,902	1,060,418	420,362	7.32	57,427
1953	1,849,159.00	1,532,343	1,310,526	538,633	7.71	69,862
1954	3,521,314.52	2,887,478	2,469,497	1,051,818	8.10	129,854
1955	2,541,433.00	2,061,382	1,762,984	778,449	8.50	91,582
1956	1,148,022.95	921,220	787,867	360,156	8.89	40,512
1957	1,568,209.00	1,244,468	1,064,323	503,886	9.29	54,240
1958	2,711,091.66	2,127,909	1,819,880	891,212	9.68	92,067
1959	1,474,588.02	1,144,280	978,638	495,950	10.08	49,201
1960	1,769,701.00	1,357,166	1,160,707	608,994	10.49	58,055
1961	2,270,739.91	1,721,221	1,472,063	798,677	10.89	73,340
1962	2,274,364.02	1,703,248	1,456,692	817,672	11.30	72,360
1963	1,481,000.00	1,095,940	937,296	543,704	11.70	46,470
1964	1,096,055.78	801,096	685,132	410,924	12.11	33,933
1965	2,246,541.39	1,621,014	1,386,362	860,179	12.53	68,650
1966	915,435.00	652,193	557,784	357,651	12.94	27,639
1967	2,813,729.95	1,978,362	1,691,981	1,121,749	13.36	83,963
1968	4,760,933.82	3,303,041	2,824,904	1,936,030	13.78	140,496
1969	2,054,255.30	1,406,014	1,202,484	851,771	14.20	59,984
1970	1,582,563.00	1,068,404	913,746	668,817	14.62	45,747
1971	1,908,733.88	1,270,377	1,086,482	822,252	15.05	54,635

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. 0						
1972	2,781,210.62	1,824,474	1,560,370	1,220,841	15.48	78,866
1973	5,643,891.05	3,648,437	3,120,302	2,523,589	15.91	158,617
1974	4,835,550.52	3,078,650	2,632,995	2,202,556	16.35	134,713
1975	9,945,358.71	6,236,834	5,334,012	4,611,347	16.78	274,812
1976	6,721,506.35	4,149,388	3,548,737	3,172,769	17.22	184,249
1977	7,202,711.50	4,374,423	3,741,197	3,461,514	17.67	195,898
1978	6,223,112.52	3,717,252	3,179,156	3,043,957	18.12	167,989
1979	2,209,118.00	1,297,481	1,109,662	1,099,456	18.57	59,206
1980	5,437,894.11	3,139,459	2,685,002	2,752,892	19.02	144,737
1981	3,238,403.33	1,836,531	1,570,681	1,667,722	19.48	85,612
1982	6,506,064.51	3,623,162	3,098,686	3,407,379	19.94	170,882
1983	3,551,630.82	1,941,570	1,660,515	1,891,116	20.40	92,702
1984	5,169,918.00	2,772,213	2,370,917	2,799,001	20.87	134,116
1985	6,371,117.58	3,348,405	2,863,702	3,507,416	21.35	164,282
1986	9,155,877.06	4,716,284	4,033,571	5,122,306	21.82	234,753
1987	11,841,867.85	5,973,512	5,108,807	6,733,061	22.30	301,931
1988	15,477,872.74	7,639,259	6,533,427	8,944,446	22.79	392,472
1989	30,939,799.80	14,933,713	12,771,961	18,167,839	23.28	780,405
1990	17,156,021.07	8,090,093	6,918,999	10,237,022	23.78	430,489
1991	11,724,520.81	5,398,438	4,616,979	7,107,542	24.28	292,732
1992	28,663,973.30	12,879,583	11,015,179	17,648,794	24.78	712,219
1993	15,478,904.70	6,776,355	5,795,433	9,683,472	25.30	382,746
1994	19,834,029.00	8,458,023	7,233,669	12,600,360	25.81	488,197
1995	6,896,677.50	2,859,845	2,445,864	4,450,814	26.34	168,975
1996	10,668,756.79	4,298,335	3,676,123	6,992,634	26.87	260,239
1997	15,582,635.88	6,094,525	5,212,303	10,370,333	27.40	378,479
1998	32,034,910.17	12,137,707	10,380,695	21,654,215	27.95	774,748
1999	9,914,251.49	3,635,259	3,109,032	6,805,219	28.50	238,780
2000	5,686,201.25	2,015,417	1,723,672	3,962,529	29.05	136,404
2001	8,874,760.95	3,033,216	2,594,138	6,280,623	29.62	212,040
2002	30,522,956.98	10,045,410	8,591,272	21,931,685	30.19	726,455
2003	25,385,093.93	8,021,690	6,860,498	18,524,596	30.78	601,839
2004	13,874,115.82	4,202,331	3,594,016	10,280,100	31.37	327,705
2005	11,996,584.20	3,473,731	2,970,886	9,025,698	31.97	282,318
2006	5,687,291.45	1,569,692	1,342,469	4,344,822	32.58	133,359
2007	17,218,329.87	4,514,990	3,861,416	13,356,914	33.20	402,317
2008	20,805,570.71	5,159,782	4,412,870	16,392,701	33.84	484,418
2009	55,426,218.53	12,957,541	11,081,853	44,344,366	34.48	1,286,090
2010	14,890,057.09	3,262,560	2,790,283	12,099,774	35.14	344,331
2011	17,079,616.11	3,487,999	2,983,088	14,096,528	35.81	393,648
2012	18,943,516.87	3,578,241	3,060,267	15,883,250	36.50	435,158

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
NET SALVAGE PERCENT.. 0						
2013	23,217,057.02	4,024,212	3,441,681	19,775,376	37.20	531,596
2014	12,914,018.47	2,031,763	1,737,652	11,176,366	37.92	294,735
2015	79,086,301.25	11,142,469	9,529,524	69,556,777	38.66	1,799,192
2016	187,503,377.58	23,250,419	19,884,770	167,618,608	39.42	4,252,121
2017	190,451,986.17	20,357,413	17,410,545	173,041,441	40.19	4,305,584
2018	176,255,121.43	15,667,318	13,399,371	162,855,750	41.00	3,972,091
2019	30,060,600.51	2,117,469	1,810,952	28,249,649	41.83	675,344
2020	34,333,277.41	1,770,224	1,513,973	32,819,304	42.68	768,962
2021	159,377,257.55	5,029,946	4,301,828	155,075,430	43.58	3,558,408
2022	68,462,746.25	745,559	637,634	67,825,112	44.51	1,523,817
	1,563,499,955.95	334,010,986	285,690,218	1,277,809,737		36,827,729
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					34.7	2.36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. 0						
1926	14,026.05	12,723	9,920	4,106	6.04	680
1927	47,862.63	43,246	33,718	14,145	6.27	2,256
1928	44,455.71	40,017	31,201	13,255	6.49	2,042
1929	47,366.51	42,477	33,119	14,248	6.71	2,123
1930	35,442.92	31,659	24,684	10,759	6.94	1,550
1931	2,932.58	2,609	2,034	899	7.17	125
1932	10,623.28	9,414	7,340	3,283	7.40	444
1933	1,512.46	1,335	1,041	471	7.63	62
1934	5,769.76	5,071	3,954	1,816	7.87	231
1935	5,021.30	4,395	3,427	1,594	8.11	197
1936	13,867.05	12,083	9,421	4,446	8.36	532
1937	17,909.27	15,540	12,116	5,793	8.60	674
1938	122,490.25	105,794	82,486	40,004	8.86	4,515
1939	121,827.54	104,753	81,674	40,154	9.11	4,408
1940	146,671.08	125,505	97,854	48,817	9.38	5,204
1941	180,577.64	153,769	119,891	60,687	9.65	6,289
1942	158,397.53	134,223	104,651	53,747	9.92	5,418
1943	126,247.08	106,416	82,971	43,276	10.21	4,239
1944	112,457.35	94,291	73,517	38,940	10.50	3,709
1945	140,651.57	117,282	91,443	49,209	10.80	4,556
1946	189,932.79	157,469	122,776	67,157	11.11	6,045
1947	188,846.80	155,638	121,348	67,499	11.43	5,905
1948	409,502.94	335,416	261,518	147,985	11.76	12,584
1949	536,958.74	436,918	340,657	196,302	12.11	16,210
1950	558,114.66	451,130	351,738	206,377	12.46	16,563
1951	752,042.68	603,604	470,619	281,424	12.83	21,935
1952	847,541.49	675,296	526,516	321,025	13.21	24,302
1953	1,066,488.20	843,347	657,543	408,945	13.60	30,069
1954	390,644.12	306,445	238,930	151,714	14.01	10,829
1955	1,372,030.12	1,067,439	832,263	539,767	14.43	37,406
1956	1,530,827.35	1,180,850	920,688	610,139	14.86	41,059
1957	1,681,127.56	1,285,424	1,002,222	678,906	15.30	44,373
1958	1,660,112.91	1,257,602	980,530	679,583	15.76	43,121
1959	1,615,169.59	1,211,619	944,678	670,492	16.24	41,286
1960	1,992,886.59	1,480,256	1,154,129	838,758	16.72	50,165
1961	1,104,957.16	812,232	633,283	471,674	17.22	27,391
1962	2,219,682.98	1,614,220	1,258,578	961,105	17.73	54,208
1963	2,398,908.00	1,725,007	1,344,957	1,053,951	18.26	57,719
1964	2,915,457.40	2,072,220	1,615,673	1,299,784	18.80	69,137
1965	3,071,469.19	2,157,124	1,681,871	1,389,598	19.35	71,814
1966	2,785,816.38	1,932,493	1,506,730	1,279,086	19.91	64,243

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. 0						
1967	3,025,634.70	2,072,318	1,615,749	1,409,886	20.48	68,842
1968	4,093,504.57	2,766,595	2,157,065	1,936,440	21.07	91,905
1969	3,945,447.04	2,630,114	2,050,653	1,894,794	21.67	87,439
1970	4,290,210.25	2,819,655	2,198,435	2,091,775	22.28	93,886
1971	4,237,552.03	2,744,620	2,139,931	2,097,621	22.90	91,599
1972	4,551,639.67	2,903,946	2,264,155	2,287,485	23.53	97,216
1973	4,240,943.30	2,663,949	2,077,033	2,163,910	24.17	89,529
1974	4,193,457.60	2,592,186	2,021,081	2,172,377	24.82	87,525
1975	3,716,382.13	2,259,560	1,761,738	1,954,644	25.48	76,713
1976	4,397,473.57	2,627,666	2,048,744	2,348,730	26.16	89,783
1977	4,378,316.06	2,570,422	2,004,112	2,374,204	26.84	88,458
1978	5,606,183.73	3,231,741	2,519,731	3,086,453	27.53	112,112
1979	6,334,908.35	3,584,608	2,794,855	3,540,053	28.22	125,445
1980	6,734,223.72	3,736,955	2,913,637	3,820,587	28.93	132,063
1981	7,882,926.87	4,288,312	3,343,520	4,539,407	29.64	153,151
1982	6,875,131.73	3,662,864	2,855,869	4,019,263	30.37	132,343
1983	8,951,691.52	4,668,665	3,640,074	5,311,618	31.10	170,792
1984	8,786,469.91	4,482,418	3,494,861	5,291,609	31.84	166,194
1985	11,090,668.44	5,530,029	4,311,665	6,779,003	32.59	208,009
1986	12,443,905.25	6,061,177	4,725,791	7,718,114	33.34	231,497
1987	14,651,576.45	6,965,066	5,430,537	9,221,039	34.10	270,412
1988	15,941,839.45	7,389,680	5,761,601	10,180,238	34.87	291,948
1989	17,242,227.70	7,785,555	6,070,258	11,171,970	35.65	313,379
1990	21,336,146.60	9,374,676	7,309,267	14,026,880	36.44	384,931
1991	16,484,645.62	7,042,735	5,491,094	10,993,552	37.23	295,287
1992	18,666,210.04	7,747,970	6,040,954	12,625,256	38.02	332,069
1993	16,294,637.09	6,560,547	5,115,141	11,179,496	38.83	287,909
1994	19,791,431.28	7,721,627	6,020,414	13,771,017	39.64	347,402
1995	16,474,842.30	6,219,912	4,849,554	11,625,288	40.46	287,328
1996	17,657,540.02	6,443,590	5,023,952	12,633,588	41.28	306,046
1997	15,373,952.70	5,413,937	4,221,150	11,152,803	42.11	264,849
1998	25,408,116.74	8,619,195	6,720,232	18,687,885	42.95	435,108
1999	8,528,300.39	2,782,870	2,169,754	6,358,546	43.79	145,205
2000	13,858,701.58	4,340,961	3,384,570	10,474,132	44.64	234,636
2001	12,885,289.81	3,865,587	3,013,929	9,871,361	45.50	216,953
2002	17,217,852.42	4,937,564	3,849,730	13,368,122	46.36	288,355
2003	13,216,009.40	3,615,107	2,818,634	10,397,375	47.22	220,190
2004	19,868,131.38	5,165,714	4,027,615	15,840,516	48.10	329,325
2005	24,737,106.28	6,100,665	4,756,579	19,980,527	48.97	408,016
2006	19,505,794.97	4,546,411	3,544,755	15,961,040	49.85	320,181
2007	25,113,690.38	5,509,441	4,295,612	20,818,078	50.74	410,289

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. 0						
2008	23,037,878.71	4,738,661	3,694,649	19,343,230	51.63	374,651
2009	29,786,706.93	5,714,580	4,455,556	25,331,151	52.53	482,223
2010	20,986,020.87	3,735,512	2,912,512	18,073,509	53.43	338,265
2011	18,897,904.29	3,102,091	2,418,645	16,479,259	54.33	303,318
2012	32,679,219.32	4,906,785	3,825,732	28,853,487	55.24	522,330
2013	37,028,693.79	5,041,457	3,930,734	33,097,960	56.15	589,456
2014	15,992,479.76	1,951,083	1,521,224	14,471,256	57.07	253,570
2015	30,712,449.21	3,312,338	2,582,571	28,129,878	57.99	485,082
2016	17,793,204.42	1,667,045	1,299,765	16,493,439	58.91	279,977
2017	24,839,622.01	1,971,769	1,537,353	23,302,269	59.84	389,410
2018	31,228,679.48	2,032,362	1,584,596	29,644,083	60.77	487,808
2019	24,042,412.14	1,217,027	948,894	23,093,518	61.71	374,227
2020	51,477,679.01	1,869,155	1,457,347	50,020,332	62.64	798,537
2021	59,022,795.99	1,289,648	1,005,516	58,017,280	63.58	912,508
2022	85,936,773.37	621,323	484,434	85,452,339	64.53	1,324,227
	1,024,137,859.55	262,141,797	204,387,268	819,750,591		17,495,526
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.9						1.71

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1937	992,853.99	805,532	992,854			
1938	108,096.95	87,036	108,097			
1939	105,521.11	84,329	105,521			
1940	130,089.10	103,161	130,089			
1941	156,644.13	123,227	156,644			
1942	125,600.14	98,010	125,600			
1943	54,390.96	42,099	54,391			
1944	77,439.14	59,435	77,439			
1945	64,033.76	48,719	64,034			
1946	171,191.23	129,135	171,191			
1947	281,839.92	210,675	281,840			
1948	395,534.44	293,024	395,534			
1949	599,840.96	440,181	599,841			
1950	496,073.10	360,645	496,073			
1951	839,525.59	604,316	839,526			
1952	890,504.53	634,778	883,176	7,329	17.23	425
1953	825,277.98	582,374	810,266	15,012	17.66	850
1954	668,590.82	466,897	649,601	18,990	18.10	1,049
1955	1,733,779.68	1,198,042	1,666,854	66,926	18.54	3,610
1956	2,104,173.29	1,438,202	2,000,993	103,180	18.99	5,433
1957	2,445,396.40	1,652,672	2,299,388	146,008	19.45	7,507
1958	2,551,208.90	1,705,049	2,372,261	178,948	19.90	8,992
1959	3,552,976.01	2,346,741	3,265,057	287,919	20.37	14,134
1960	6,104,902.22	3,984,487	5,543,678	561,224	20.84	26,930
1961	1,536,035.13	990,482	1,378,073	157,962	21.31	7,413
1962	6,696,162.43	4,264,317	5,933,010	763,152	21.79	35,023
1963	8,018,986.90	5,041,296	7,014,033	1,004,954	22.28	45,106
1964	8,690,314.32	5,392,340	7,502,446	1,187,868	22.77	52,168
1965	10,280,379.23	6,293,340	8,756,021	1,524,358	23.27	65,507
1966	9,019,697.74	5,446,364	7,577,610	1,442,088	23.77	60,668
1967	10,434,891.97	6,212,204	8,643,135	1,791,757	24.28	73,796
1968	12,410,737.00	7,282,993	10,132,941	2,277,796	24.79	91,884
1969	11,286,336.85	6,523,503	9,076,251	2,210,086	25.32	87,286
1970	11,271,422.97	6,417,159	8,928,292	2,343,131	25.84	90,678
1971	7,941,017.29	4,450,940	6,192,662	1,748,355	26.37	66,301
1972	11,813,836.95	6,515,331	9,064,881	2,748,956	26.91	102,154
1973	11,210,723.05	6,079,911	8,459,074	2,751,649	27.46	100,206
1974	10,919,493.60	5,821,946	8,100,163	2,819,331	28.01	100,654
1975	6,279,464.31	3,290,439	4,578,039	1,701,425	28.56	59,574
1976	7,530,805.18	3,875,880	5,392,572	2,138,233	29.12	73,428
1977	7,990,558.00	4,036,590	5,616,170	2,374,388	29.69	79,973

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1978	8,642,269.49	4,283,714	5,959,997	2,682,272	30.26	88,641
1979	9,779,072.38	4,752,629	6,612,406	3,166,666	30.84	102,680
1980	10,379,960.87	4,944,287	6,879,063	3,500,898	31.42	111,423
1981	12,154,702.14	5,670,169	7,888,994	4,265,708	32.01	133,262
1982	6,050,703.57	2,762,146	3,843,016	2,207,688	32.61	67,700
1983	12,834,077.34	5,730,416	7,972,816	4,861,261	33.21	146,379
1984	13,311,693.37	5,810,554	8,084,314	5,227,379	33.81	154,610
1985	14,591,806.80	6,218,590	8,652,020	5,939,787	34.43	172,518
1986	16,524,364.35	6,874,136	9,564,092	6,960,272	35.04	198,638
1987	20,812,532.53	8,443,020	11,746,904	9,065,629	35.66	254,224
1988	21,259,550.16	8,401,136	11,688,630	9,570,920	36.29	263,734
1989	23,040,059.51	8,862,820	12,330,978	10,709,082	36.92	290,062
1990	27,739,573.76	10,379,316	14,440,903	13,298,671	37.55	354,159
1991	24,713,472.43	8,983,347	12,498,669	12,214,803	38.19	319,843
1992	26,834,290.64	9,463,649	13,166,921	13,667,370	38.84	351,889
1993	25,129,134.77	8,589,892	11,951,249	13,177,886	39.49	333,702
1994	26,730,294.96	8,847,728	12,309,981	14,420,314	40.14	359,250
1995	23,535,374.29	7,535,321	10,484,009	13,051,365	40.79	319,965
1996	19,791,217.94	6,118,851	8,513,252	11,277,966	41.45	272,086
1997	28,269,415.99	8,424,286	11,720,839	16,548,577	42.12	392,891
1998	30,805,084.10	8,841,059	12,300,702	18,504,382	42.78	432,547
1999	10,552,280.98	2,910,636	4,049,613	6,502,668	43.45	149,659
2000	26,597,686.00	7,039,610	9,794,318	16,803,368	44.12	380,856
2001	20,077,270.64	5,086,175	7,076,474	13,000,797	44.80	290,196
2002	21,452,924.41	5,191,608	7,223,164	14,229,760	45.48	312,880
2003	19,545,119.80	4,508,473	6,272,708	13,272,412	46.16	287,531
2004	26,320,534.16	5,772,883	8,031,901	18,288,633	46.84	390,449
2005	24,541,322.33	5,104,595	7,102,102	17,439,220	47.52	366,987
2006	28,033,670.83	5,508,616	7,664,223	20,369,448	48.21	422,515
2007	31,249,649.20	5,781,185	8,043,452	23,206,197	48.90	474,564
2008	36,996,061.51	6,412,527	8,921,848	28,074,214	49.60	566,012
2009	57,103,307.47	9,241,028	12,857,185	44,246,122	50.29	879,819
2010	52,898,295.51	7,943,737	11,052,244	41,846,052	50.99	820,672
2011	63,602,026.18	8,808,881	12,255,932	51,346,094	51.69	993,347
2012	99,647,292.19	12,622,323	17,561,633	82,085,659	52.40	1,566,520
2013	114,479,552.27	13,165,149	18,316,875	96,162,677	53.10	1,810,973
2014	84,744,882.68	8,743,130	12,164,452	72,580,431	53.81	1,348,828
2015	167,872,511.74	15,304,937	21,293,996	146,578,516	54.53	2,688,034
2016	166,517,395.62	13,183,182	18,341,965	148,175,431	55.25	2,681,908
2017	192,149,840.51	12,906,705	17,957,298	174,192,543	55.97	3,112,248
2018	238,391,541.97	13,152,061	18,298,666	220,092,876	56.69	3,882,393

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
2019	143,794,945.32	6,183,183	8,602,758	135,192,187	57.42	2,354,444
2020	174,856,271.08	5,390,819	7,500,330	167,355,941	58.15	2,878,004
2021	267,079,707.66	4,940,975	6,874,455	260,205,253	58.89	4,418,496
2022	205,294,037.98	1,266,664	1,762,329	203,531,709	59.63	3,413,243
	2,855,533,126.70	441,539,949	614,064,997	2,241,468,130		42,871,530
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					52.3	1.50

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1926	4,690,473.24	4,439,064	4,690,473			
1927	1,225,303.94	1,155,376	1,225,304			
1928	1,782,679.06	1,674,773	1,782,679			
1929	1,875,880.28	1,755,824	1,875,880			
1930	1,554,191.37	1,449,128	1,554,191			
1931	1,068,529.87	992,451	1,068,530			
1932	453,389.21	419,476	453,389			
1933	69,611.13	64,145	69,611			
1934	491,923.64	451,453	491,924			
1935	646,768.42	591,062	646,768			
1936	455,122.63	414,162	455,123			
1937	568,215.71	514,803	568,216			
1938	2,505,863.25	2,259,963	2,505,863			
1939	911,556.70	818,213	911,557			
1940	681,666.24	608,864	681,666			
1941	494,013.18	439,015	494,013			
1942	182,900.26	161,660	182,900			
1943	112,607.67	98,974	112,608			
1944	23,238.17	20,304	23,238			
1945	59,546.58	51,703	59,547			
1946	147,097.58	126,897	147,098			
1947	197,140.88	168,885	197,141			
1948	191,960.98	163,269	191,961			
1949	212,770.60	179,578	212,771			
1950	480,517.18	402,289	480,517			
1951	732,456.23	608,034	732,456			
1952	1,250,061.63	1,028,551	1,250,062			
1953	1,449,816.05	1,181,890	1,449,816			
1954	1,512,600.78	1,220,971	1,512,601			
1955	1,556,324.11	1,243,612	1,556,324			
1956	1,069,457.81	845,588	1,069,458			
1957	2,259,299.83	1,767,066	2,259,300			
1958	1,458,633.01	1,128,005	1,458,633			
1959	1,321,438.56	1,010,108	1,321,439			
1960	1,775,407.27	1,341,018	1,775,407			
1961	3,704,285.10	2,764,397	3,704,285			
1962	3,424,540.98	2,523,647	3,424,541			
1963	2,809,858.83	2,044,088	2,809,859			
1964	2,351,863.23	1,688,638	2,351,863			
1965	2,578,748.52	1,826,450	2,562,137	16,612	21.88	759
1966	2,701,558.05	1,887,119	2,647,244	54,314	22.61	2,402

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1967	2,897,057.72	1,994,711	2,798,173	98,885	23.36	4,233
1968	4,099,291.82	2,781,492	3,901,867	197,425	24.11	8,189
1969	3,938,373.14	2,631,897	3,692,016	246,357	24.88	9,902
1970	3,361,924.59	2,212,146	3,103,190	258,735	25.65	10,087
1971	2,800,300.91	1,813,111	2,543,426	256,875	26.44	9,715
1972	3,036,433.09	1,933,995	2,713,001	323,432	27.23	11,878
1973	3,596,432.96	2,251,835	3,158,866	437,567	28.04	15,605
1974	3,114,025.98	1,916,154	2,687,974	426,052	28.85	14,768
1975	2,215,549.03	1,338,790	1,878,050	337,499	29.68	11,371
1976	2,045,099.21	1,213,153	1,701,807	343,292	30.51	11,252
1977	2,261,464.13	1,316,172	1,846,321	415,143	31.35	13,242
1978	1,831,840.87	1,045,120	1,466,091	365,750	32.21	11,355
1979	3,911,702.90	2,186,916	3,067,798	843,905	33.07	25,519
1980	1,473,849.47	806,888	1,131,900	341,949	33.94	10,075
1981	4,447,506.68	2,383,285	3,343,264	1,104,243	34.81	31,722
1982	1,811,018.14	948,974	1,331,217	479,801	35.70	13,440
1983	2,206,449.25	1,129,989	1,585,144	621,305	36.59	16,980
1984	2,855,271.05	1,428,007	2,003,203	852,068	37.49	22,728
1985	4,469,253.37	2,180,996	3,059,493	1,409,760	38.40	36,712
1986	4,958,315.69	2,358,820	3,308,944	1,649,372	39.32	41,947
1987	18,411,375.46	8,533,120	11,970,230	6,441,145	40.24	160,068
1988	12,679,487.68	5,720,985	8,025,377	4,654,111	41.16	113,074
1989	14,934,793.68	6,551,446	9,190,345	5,744,449	42.10	136,448
1990	16,948,541.45	7,222,282	10,131,391	6,817,150	43.04	158,391
1991	12,743,859.73	5,270,860	7,393,943	5,349,917	43.98	121,644
1992	12,795,464.56	5,130,086	7,196,466	5,598,999	44.93	124,616
1993	13,459,068.56	5,225,753	7,330,667	6,128,402	45.88	133,575
1994	10,326,741.49	3,877,382	5,439,177	4,887,564	46.84	104,346
1995	14,003,961.02	5,078,817	7,124,546	6,879,415	47.80	143,921
1996	6,314,260.94	2,208,286	3,097,776	3,216,485	48.77	65,952
1997	8,017,442.90	2,701,317	3,789,398	4,228,045	49.73	85,020
1998	24,673,592.25	7,991,036	11,209,797	13,463,795	50.71	265,506
1999	16,498,048.05	5,129,738	7,195,978	9,302,070	51.68	179,994
2000	16,433,355.66	4,895,004	6,866,694	9,566,662	52.66	181,668
2001	4,294,730.75	1,223,139	1,715,815	2,578,916	53.64	48,078
2002	14,000,327.45	3,804,309	5,336,671	8,663,656	54.62	158,617
2003	17,813,184.41	4,607,736	6,463,715	11,349,469	55.60	204,127
2004	7,643,382.82	1,876,221	2,631,956	5,011,427	56.59	88,557
2005	10,362,165.01	2,406,820	3,376,278	6,985,887	57.58	121,325
2006	11,404,378.04	2,498,357	3,504,686	7,899,692	58.57	134,876
2007	13,581,401.58	2,796,003	3,922,223	9,659,179	59.56	162,176

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2008	17,669,985.42	3,404,476	4,775,787	12,894,198	60.55	212,951
2009	31,495,134.73	5,652,432	7,929,211	23,565,924	61.54	382,937
2010	12,544,338.59	2,085,747	2,925,879	9,618,460	62.53	153,822
2011	12,777,305.54	1,954,033	2,741,110	10,036,196	63.53	157,976
2012	410,755.54	57,395	80,514	330,242	64.52	5,118
2013	13,440,868.57	1,698,926	2,383,247	11,057,622	65.52	168,767
2014	30,094.07	3,403	4,774	25,320	66.52	381
2015	3,497,248.32	349,270	489,955	3,007,293	67.51	44,546
2016	1,261,608.51	109,167	153,139	1,108,470	68.51	16,180
2017	3,280,653.03	240,144	336,873	2,943,780	69.51	42,350
2018	5,187,196.33	310,557	435,648	4,751,548	70.51	67,388
2019	2,935,887.07	137,018	192,208	2,743,679	71.50	38,373
2020	2,021,827.58	67,388	94,532	1,927,296	72.50	26,583
2021	8,832,231.15	176,645	247,797	8,584,434	73.50	116,795
2022	2,702,474.63	18,026	25,287	2,677,188	74.50	35,935
	509,797,650.33	190,416,288	259,019,228	250,778,423		4,695,962

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 53.4 0.92

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. 0						
1938	2,034.34	1,808	2,034			
1939	11,681.52	10,326	11,682			
1940	60,583.22	53,251	60,583			
1941	73,868.79	64,546	73,869			
1942	47,499.28	41,259	47,499			
1943	20,452.21	17,659	20,452			
1944	20,826.85	17,872	20,827			
1945	41,013.35	34,975	41,013			
1946	60,344.13	51,136	60,344			
1947	8,582.30	7,225	8,582			
1948	236,323.14	197,616	236,323			
1949	248,790.29	206,625	248,790			
1950	221,444.80	182,617	221,445			
1951	410,421.03	335,979	410,421			
1952	471,298.00	382,972	471,298			
1955	1,253,629.54	994,692	1,253,630			
1956	1,162,772.15	914,985	1,162,772			
1957	1,213,293.95	946,369	1,213,294			
1958	1,392,203.16	1,076,076	1,385,280	6,923	13.17	526
1959	1,387,990.43	1,063,006	1,368,454	19,536	13.58	1,439
1960	2,106,658.29	1,597,795	2,056,911	49,747	14.01	3,551
1962	343,938.28	255,642	329,099	14,839	14.89	997
1963	2,446,666.77	1,799,572	2,316,667	130,000	15.34	8,475
1964	2,829,429.84	2,058,156	2,649,554	179,876	15.81	11,377
1965	2,216,273.79	1,594,188	2,052,268	164,006	16.28	10,074
1966	3,221,123.24	2,289,768	2,947,718	273,405	16.77	16,303
1967	3,919,546.75	2,752,463	3,543,366	376,181	17.27	21,782
1968	4,690,110.58	3,253,155	4,187,928	502,183	17.77	28,260
1969	6,044,197.01	4,138,220	5,327,311	716,886	18.29	39,196
1970	5,927,857.80	4,004,387	5,155,022	772,836	18.82	41,065
1972	6,187,412.70	4,064,511	5,232,422	954,991	19.90	47,989
1973	6,292,575.76	4,072,807	5,243,102	1,049,474	20.46	51,294
1974	5,025,984.73	3,203,613	4,124,151	901,834	21.03	42,883
1975	5,900,133.70	3,702,865	4,766,859	1,133,275	21.60	52,466
1976	5,488,831.07	3,388,859	4,362,626	1,126,205	22.19	50,753
1977	4,006,734.39	2,432,368	3,131,293	875,441	22.79	38,413
1978	5,684,185.20	3,391,867	4,366,498	1,317,687	23.39	56,335
1979	7,422,396.78	4,349,747	5,599,619	1,822,778	24.01	75,917
1980	6,243,397.08	3,592,076	4,624,236	1,619,161	24.63	65,739
1981	6,922,933.73	3,906,681	5,029,241	1,893,693	25.27	74,938
1982	29,302.39	16,212	20,870	8,432	25.91	325

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. 0						
1983	7,338,820.60	3,978,154	5,121,251	2,217,570	26.56	83,493
1984	9,847,838.69	5,226,150	6,727,851	3,119,988	27.22	114,621
1985	11,611,143.25	6,027,809	7,759,861	3,851,282	27.89	138,088
1986	12,532,340.27	6,359,035	8,186,263	4,346,077	28.57	152,120
1987	22,030,541.98	10,920,319	14,058,202	7,972,340	29.25	272,559
1988	17,396,280.32	8,413,189	10,830,665	6,565,615	29.95	219,219
1989	23,596,058.98	11,126,722	14,323,914	9,272,145	30.65	302,517
1990	12,237,348.87	5,620,737	7,235,820	5,001,529	31.36	159,488
1991	24,864,815.34	11,112,086	14,305,072	10,559,743	32.08	329,169
1992	22,615,417.92	9,825,947	12,649,370	9,966,048	32.80	303,843
1993	29,282,996.96	12,354,496	15,904,481	13,378,516	33.53	399,001
1994	25,327,295.28	10,362,410	13,339,982	11,987,313	34.27	349,790
1995	22,199,233.94	8,795,558	11,322,905	10,876,329	35.02	310,575
1996	25,396,650.14	9,729,457	12,525,154	12,871,496	35.78	359,740
1997	31,070,504.81	11,496,087	14,799,414	16,271,091	36.54	445,295
1998	45,548,028.07	16,247,893	20,916,620	24,631,408	37.31	660,182
1999	20,233,417.49	6,949,167	8,945,965	11,287,452	38.08	296,414
2000	32,013,452.91	10,564,439	13,600,063	18,413,390	38.86	473,839
2001	33,185,048.18	10,499,086	13,515,931	19,669,117	39.65	496,069
2002	33,438,545.20	10,118,169	13,025,560	20,412,985	40.45	504,647
2003	35,150,408.30	10,151,086	13,067,935	22,082,473	41.25	535,333
2004	31,113,251.12	8,550,855	11,007,888	20,105,363	42.06	478,016
2005	35,615,055.98	9,290,544	11,960,122	23,654,934	42.87	551,783
2006	40,988,021.37	10,112,565	13,018,345	27,969,676	43.69	640,185
2007	44,455,836.71	10,331,981	13,300,809	31,155,028	44.52	699,798
2008	45,039,331.29	9,823,078	12,645,676	32,393,655	45.35	714,303
2009	193,856,939.36	39,473,150	50,815,506	143,041,433	46.19	3,096,805
2010	34,640,436.31	6,551,892	8,434,536	26,205,900	47.03	557,217
2011	45,729,315.49	7,978,851	10,271,522	35,457,793	47.88	740,555
2012	55,276,124.55	8,834,783	11,373,401	43,902,724	48.73	900,938
2013	52,950,507.28	7,677,824	9,883,997	43,066,510	49.59	868,452
2014	15,562,973.30	2,023,187	2,604,537	12,958,436	50.46	256,806
2015	34,496,543.04	3,972,967	5,114,573	29,381,970	51.32	572,525
2016	30,759,094.96	3,075,909	3,959,752	26,799,343	52.20	513,397
2017	36,010,189.95	3,054,744	3,932,505	32,077,685	53.08	604,327
2018	39,633,833.44	2,760,893	3,554,218	36,079,615	53.96	668,636
2019	35,040,487.19	1,903,049	2,449,878	32,590,609	54.85	594,177

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R2						
NET SALVAGE PERCENT.. 0						
2020	19,642,322.69	761,926	980,860	18,661,463	55.75	334,735
2021	41,135,225.15	964,621	1,241,799	39,893,426	56.64	704,333
2022	31,197,223.56	242,090	311,653	30,885,570	57.55	536,674
	1,461,353,642.60	399,728,851	514,409,209	946,944,434		21,679,761
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					43.7	1.48

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
1930	341,473.41	325,704	250,664	90,809	2.54	35,752
1931	281,658.86	267,218	205,652	76,007	2.82	26,953
1932	278,501.73	262,805	202,256	76,246	3.10	24,595
1933	366,909.87	344,294	264,971	101,939	3.39	30,071
1934	325,651.07	303,862	233,854	91,797	3.68	24,945
1935	256,489.33	238,022	183,183	73,306	3.96	18,512
1936	1,186,501.10	1,094,820	842,580	343,921	4.25	80,923
1937	1,486,930.11	1,364,184	1,049,884	437,046	4.54	96,266
1938	1,528,894.82	1,394,627	1,073,313	455,582	4.83	94,323
1939	950,746.11	862,241	663,586	287,160	5.12	56,086
1940	30,980.01	27,933	21,497	9,483	5.41	1,753
1941	78,278.34	70,166	54,000	24,278	5.70	4,259
1942	624,739.36	556,699	428,439	196,300	5.99	32,771
1943	72,460.47	64,174	49,389	23,071	6.29	3,668
1944	198,961.38	175,158	134,803	64,158	6.58	9,750
1945	136,400.10	119,338	91,843	44,557	6.88	6,476
1946	130,615.87	113,564	87,399	43,217	7.18	6,019
1947	83,854.70	72,450	55,758	28,097	7.48	3,756
1948	74,370.81	63,851	49,140	25,231	7.78	3,243
1949	330,211.17	281,640	216,752	113,459	8.09	14,025
1950	316,302.50	267,937	206,206	110,096	8.41	13,091
1951	185,338.83	155,920	119,997	65,342	8.73	7,485
1952	237,896.82	198,708	152,927	84,970	9.06	9,379
1953	942,347.23	781,460	601,416	340,931	9.39	36,308
1954	1,006,513.61	828,451	637,581	368,933	9.73	37,917
1955	703,544.40	574,606	442,220	261,324	10.08	25,925
1956	6,808,857.36	5,517,626	4,246,396	2,562,461	10.43	245,682
1957	3,986,139.16	3,203,421	2,465,371	1,520,768	10.80	140,812
1958	4,984,094.79	3,971,875	3,056,778	1,927,317	11.17	172,544
1959	3,074,713.70	2,429,024	1,869,391	1,205,323	11.55	104,357
1960	6,282,240.86	4,917,298	3,784,380	2,497,861	11.95	209,026
1961	6,399,005.04	4,962,108	3,818,867	2,580,138	12.35	208,918
1962	8,077,068.13	6,203,188	4,774,009	3,303,059	12.76	258,860
1963	13,085,240.92	9,949,494	7,657,187	5,428,054	13.18	411,840
1964	11,475,604.26	8,633,786	6,644,611	4,830,993	13.62	354,698
1965	6,031,179.30	4,489,369	3,455,044	2,576,135	14.06	183,224
1966	5,670,952.11	4,174,842	3,212,982	2,457,970	14.51	169,398
1967	8,789,927.86	6,395,903	4,922,323	3,867,605	14.98	258,185
1968	6,081,285.85	4,372,992	3,365,479	2,715,807	15.45	175,780
1969	5,967,277.06	4,237,841	3,261,467	2,705,810	15.94	169,750
1970	5,795,089.74	4,062,879	3,126,815	2,668,275	16.44	162,304

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
1971	13,439,785.54	9,297,912	7,155,726	6,284,060	16.95	370,741
1972	14,694,698.87	10,027,075	7,716,894	6,977,805	17.47	399,416
1973	14,459,980.99	9,730,266	7,488,468	6,971,513	17.99	387,522
1974	12,588,711.01	8,345,182	6,422,499	6,166,212	18.54	332,590
1975	11,166,160.56	7,290,498	5,610,809	5,555,352	19.09	291,008
1976	7,866,817.13	5,056,239	3,891,310	3,975,507	19.65	202,316
1977	7,323,795.33	4,631,275	3,564,256	3,759,539	20.22	185,932
1978	15,431,596.89	9,595,676	7,384,887	8,046,710	20.80	386,861
1979	13,819,364.99	8,442,388	6,497,310	7,322,055	21.40	342,152
1980	17,463,383.58	10,478,030	8,063,951	9,399,433	22.00	427,247
1981	15,697,378.55	9,244,343	7,114,499	8,582,880	22.61	379,605
1982	9,718,086.24	5,613,555	4,320,224	5,397,862	23.23	232,366
1983	18,193,481.97	10,297,511	7,925,023	10,268,459	23.87	430,183
1984	35,514,470.23	19,687,802	15,151,844	20,362,626	24.51	830,788
1985	31,381,429.73	17,025,995	13,103,302	18,278,128	25.16	726,476
1986	41,765,252.68	22,158,555	17,053,350	24,711,903	25.82	957,084
1987	40,772,166.76	21,134,660	16,265,354	24,506,813	26.49	925,135
1988	35,452,654.12	17,939,043	13,805,989	21,646,665	27.17	796,712
1989	34,866,754.10	17,211,624	13,246,164	21,620,590	27.85	776,323
1990	11,785,430.67	5,667,731	4,361,918	7,423,513	28.55	260,018
1991	9,878,005.43	4,624,685	3,559,184	6,318,821	29.25	216,028
1992	15,988,683.24	7,279,168	5,602,089	10,386,594	29.96	346,682
1993	18,689,662.51	8,264,195	6,360,171	12,329,492	30.68	401,874
1994	10,787,453.15	4,626,847	3,560,848	7,226,605	31.41	230,073
1995	15,422,186.81	6,407,148	4,930,977	10,491,210	32.15	326,321
1996	24,497,715.67	9,848,082	7,579,140	16,918,576	32.89	514,399
1997	22,251,926.79	8,641,758	6,650,746	15,601,181	33.64	463,769
1998	21,429,825.03	8,026,541	6,177,272	15,252,553	34.40	443,388
1999	11,660,337.08	4,204,135	3,235,526	8,424,811	35.17	239,545
2000	13,822,116.52	4,790,054	3,686,453	10,135,664	35.94	282,016
2001	19,620,763.70	6,521,157	5,018,719	14,602,045	36.72	397,659
2002	30,572,529.98	9,722,065	7,482,156	23,090,374	37.51	615,579
2003	13,228,598.00	4,014,218	3,089,365	10,139,233	38.31	264,663
2004	18,908,289.73	5,462,794	4,204,197	14,704,093	39.11	375,968
2005	19,692,027.31	5,399,160	4,155,224	15,536,803	39.92	389,198
2006	20,629,333.37	5,352,281	4,119,146	16,510,187	40.73	405,357
2007	15,617,264.31	3,819,202	2,939,280	12,677,984	41.55	305,126
2008	16,455,690.81	3,775,758	2,905,845	13,549,846	42.38	319,723
2009	40,449,980.61	8,670,858	6,673,142	33,776,839	43.21	781,690
2010	14,567,995.19	2,900,342	2,232,120	12,335,875	44.05	280,043
2011	19,977,802.16	3,672,320	2,826,238	17,151,564	44.89	382,080

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2012	43,384,414.55	7,296,391	5,615,344	37,769,071	45.75	825,553
2013	45,658,175.88	6,973,373	5,366,747	40,291,429	46.60	864,623
2014	39,184,004.61	5,371,735	4,134,118	35,049,887	47.46	738,514
2015	53,083,898.96	6,437,484	4,954,324	48,129,575	48.33	995,853
2016	53,665,422.88	5,659,019	4,355,213	49,310,210	49.20	1,002,240
2017	57,245,843.08	5,120,641	3,940,875	53,304,968	50.08	1,064,396
2018	70,223,950.93	5,145,309	3,959,859	66,264,092	50.97	1,300,061
2019	61,837,475.74	3,541,432	2,725,506	59,111,970	51.85	1,140,057
2020	75,360,533.40	3,082,999	2,372,694	72,987,839	52.75	1,383,656
2021	79,123,886.65	1,942,491	1,494,952	77,628,935	53.65	1,446,951
2022	91,161,268.42	745,699	573,894	90,587,374	54.55	1,660,630
	1,582,143,710.59	494,546,179	380,605,551	1,201,538,160		33,973,819
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					35.4	2.15

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1926	33,829.15	33,538	33,829			
1927	23,067.93	22,795	23,068			
1928	24,000.17	23,646	24,000			
1929	30,344.58	29,798	30,345			
1930	29,607.40	28,979	29,607			
1931	21,033.83	20,519	21,034			
1932	15,552.04	15,117	15,552			
1933	11,232.12	10,880	11,232			
1934	20,670.69	19,946	20,671			
1935	48,695.94	46,815	48,696			
1936	46,335.62	44,368	46,336			
1937	2,615.42	2,494	2,615			
1938	103,123.58	97,952	103,124			
1939	73,360.06	69,388	73,360			
1940	86,286.54	81,269	86,287			
1941	95,988.75	90,023	95,989			
1942	56,263.26	52,541	56,263			
1943	29,835.46	27,738	29,835			
1944	23,992.12	22,202	23,992			
1945	44,973.47	41,431	44,973			
1946	139,788.66	128,175	139,789			
1947	241,082.06	219,978	241,082			
1948	313,867.56	284,945	313,868			
1949	373,884.23	337,647	373,884			
1950	479,130.48	430,408	479,130			
1951	598,635.23	534,719	598,635			
1952	553,825.93	491,714	553,826			
1953	587,338.42	518,215	587,338			
1954	28,480.73	24,962	28,481			
1955	162,371.29	141,338	162,371			
1956	860,026.34	743,063	860,026			
1957	788,449.84	675,883	788,450			
1958	867,164.82	737,090	867,165			
1959	1,050,793.22	885,251	1,050,793			
1960	1,120,002.19	934,776	1,120,002			
1961	1,313,312.33	1,084,993	1,313,312			
1962	1,542,138.90	1,260,760	1,542,139			
1963	1,657,839.69	1,340,297	1,657,840			
1964	1,607,821.31	1,284,778	1,597,542	10,279	13.06	787
1965	1,706,871.37	1,347,370	1,675,371	31,500	13.69	2,301
1966	1,847,978.10	1,440,277	1,790,896	57,082	14.34	3,981

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1967	1,898,702.79	1,460,539	1,816,090	82,613	15.00	5,508
1968	2,125,550.29	1,613,123	2,005,819	119,731	15.67	7,641
1969	2,642,940.52	1,977,739	2,459,196	183,745	16.36	11,231
1970	2,638,797.46	1,946,614	2,420,494	218,303	17.05	12,804
1971	2,716,969.93	1,974,612	2,455,308	261,662	17.76	14,733
1972	2,706,616.23	1,937,098	2,408,662	297,954	18.48	16,123
1973	2,987,490.84	2,105,046	2,617,495	369,996	19.20	19,271
1974	3,283,090.29	2,275,937	2,829,987	453,103	19.94	22,723
1975	3,456,303.54	2,356,128	2,929,700	526,604	20.69	25,452
1976	3,485,922.17	2,335,045	2,903,484	582,438	21.46	27,141
1977	3,437,431.45	2,261,830	2,812,446	624,985	22.23	28,114
1978	4,086,856.96	2,639,497	3,282,052	804,805	23.02	34,961
1979	4,981,923.79	3,156,995	3,925,529	1,056,395	23.81	44,368
1980	4,089,293.62	2,540,392	3,158,821	930,473	24.62	37,793
1981	4,687,929.40	2,853,168	3,547,738	1,140,191	25.44	44,819
1982	4,838,762.40	2,883,177	3,585,053	1,253,709	26.27	47,724
1983	5,904,182.84	3,440,781	4,278,399	1,625,784	27.12	59,948
1984	7,293,090.29	4,154,801	5,166,239	2,126,851	27.97	76,040
1985	8,769,631.85	4,879,949	6,067,916	2,701,716	28.83	93,712
1986	9,321,471.65	5,062,305	6,294,664	3,026,808	29.70	101,913
1987	8,483,717.49	4,492,468	5,586,107	2,897,610	30.58	94,755
1988	9,581,235.52	4,942,480	6,145,669	3,435,567	31.47	109,170
1989	9,204,142.23	4,620,479	5,745,281	3,458,861	32.37	106,854
1990	8,941,099.62	4,363,257	5,425,441	3,515,659	33.28	105,639
1991	8,406,704.68	3,983,517	4,953,258	3,453,447	34.20	100,978
1992	9,277,733.28	4,264,881	5,303,116	3,974,617	35.12	113,172
1993	11,966,044.68	5,329,437	6,626,826	5,339,219	36.05	148,106
1994	13,640,674.15	5,878,039	7,308,979	6,331,695	36.99	171,173
1995	14,091,181.68	5,868,414	7,297,011	6,794,171	37.93	179,124
1996	15,455,722.71	6,210,882	7,722,849	7,732,874	38.88	198,891
1997	12,572,156.23	4,868,316	6,053,451	6,518,705	39.83	163,663
1998	14,936,159.64	5,563,122	6,917,399	8,018,761	40.79	196,586
1999	12,258,017.98	4,384,570	5,451,942	6,806,076	41.75	163,020
2000	14,922,657.70	5,115,039	6,360,236	8,562,422	42.72	200,431
2001	14,044,465.28	4,604,478	5,725,384	8,319,081	43.69	190,412
2002	12,845,715.65	4,019,681	4,998,225	7,847,491	44.66	175,716
2003	20,407,111.80	6,078,258	7,557,939	12,849,173	45.64	281,533
2004	23,559,990.33	6,662,058	8,283,858	15,276,132	46.62	327,673
2005	18,311,928.10	4,901,920	6,095,235	12,216,693	47.60	256,653
2006	19,925,647.92	5,033,617	6,258,992	13,666,656	48.58	281,323
2007	19,561,942.25	4,643,614	5,774,048	13,787,894	49.57	278,150

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
2008	18,059,100.12	4,011,829	4,988,462	13,070,638	50.56	258,517
2009	16,264,712.66	3,365,494	4,184,784	12,079,929	51.55	234,334
2010	18,449,034.02	3,536,495	4,397,414	14,051,620	52.54	267,446
2011	14,799,868.26	2,611,585	3,247,345	11,552,523	53.53	215,814
2012	9,307,111.70	1,499,190	1,864,150	7,442,962	54.53	136,493
2013	940,669.03	137,197	170,596	770,073	55.52	13,870
2014	3,077,368.46	401,473	499,207	2,578,161	56.52	45,615
2015	3,728,103.02	429,589	534,167	3,193,936	57.51	55,537
2016	6,300,410.65	629,096	782,242	5,518,169	58.51	94,312
2017	4,931,628.13	416,525	517,923	4,413,705	59.51	74,167
2018	17,916,432.36	1,237,667	1,538,963	16,377,469	60.51	270,657
2019	4,514,150.93	243,087	302,264	4,211,887	61.50	68,486
2020	10,106,114.15	388,681	483,301	9,622,813	62.50	153,965
2021	2,250,329.07	51,938	64,582	2,185,747	63.50	34,421
2022	8,064,424.92	62,015	77,111	7,987,314	64.50	123,834
	535,118,075.54	194,333,242	240,771,597	294,346,478		6,629,578
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					44.4	1.24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. 0						
1950	361,966.84	328,666	243,900	118,067	1.84	64,167
1951	114,675.25	103,437	76,760	37,915	1.96	19,344
1952	252,559.64	226,293	167,930	84,630	2.08	40,688
1953	471,747.78	419,856	311,571	160,177	2.20	72,808
1954	78,486.19	69,343	51,459	27,027	2.33	11,600
1955	149,296.81	131,008	97,220	52,077	2.45	21,256
1956	204,757.23	178,344	132,347	72,410	2.58	28,066
1957	300,219.43	259,540	192,602	107,617	2.71	39,711
1958	332,194.37	285,023	211,513	120,681	2.84	42,493
1959	364,754.07	310,588	230,484	134,270	2.97	45,209
1960	486,258.07	410,645	304,735	181,523	3.11	58,368
1961	521,332.56	436,877	324,202	197,131	3.24	60,843
1962	597,947.93	496,895	368,741	229,207	3.38	67,813
1963	576,823.99	475,591	352,931	223,893	3.51	63,787
1964	544,911.98	446,010	330,979	213,933	3.63	58,935
1965	613,539.00	498,194	369,705	243,834	3.76	64,849
1966	667,450.51	538,299	399,466	267,985	3.87	69,247
1967	557,772.44	446,776	331,548	226,224	3.98	56,840
1968	534,478.19	425,177	315,519	218,959	4.09	53,535
1969	515,437.03	407,453	302,367	213,070	4.19	50,852
1970	497,783.51	390,760	289,979	207,805	4.30	48,327
1971	1,044,159.54	814,444	604,390	439,770	4.40	99,948
1972	1,132,631.08	877,789	651,398	481,233	4.50	106,941
1973	1,233,442.69	949,134	704,342	529,101	4.61	114,772
1974	881,867.91	673,747	499,981	381,887	4.72	80,908
1975	681,041.57	516,570	383,341	297,701	4.83	61,636
1976	630,707.41	474,607	352,201	278,506	4.95	56,264
1977	640,710.12	478,290	354,934	285,776	5.07	56,366
1978	2,208,616.18	1,634,376	1,212,853	995,763	5.20	191,493
1979	1,776,253.55	1,301,994	966,196	810,058	5.34	151,696
1980	849,101.23	616,447	457,459	391,642	5.48	71,468
1981	911,579.46	654,970	486,046	425,533	5.63	75,583
1982	1,585,088.26	1,126,998	836,333	748,755	5.78	129,542
1983	1,856,191.86	1,304,903	968,355	887,837	5.94	149,468
1984	2,364,403.33	1,642,078	1,218,569	1,145,834	6.11	187,534
1985	2,304,108.23	1,579,466	1,172,105	1,132,003	6.29	179,969
1986	2,727,472.71	1,845,135	1,369,255	1,358,218	6.47	209,926
1987	3,415,528.35	2,278,157	1,690,597	1,724,931	6.66	258,999
1988	3,681,540.27	2,420,613	1,796,312	1,885,228	6.85	275,216
1989	3,703,120.60	2,397,771	1,779,361	1,923,760	7.05	272,874
1990	3,335,892.73	2,124,964	1,576,914	1,758,979	7.26	242,284

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. 0						
1991	3,309,241.98	2,073,240	1,538,530	1,770,712	7.47	237,043
1992	3,954,930.91	2,434,260	1,806,439	2,148,492	7.69	279,388
1993	3,855,242.27	2,328,566	1,728,004	2,127,238	7.92	268,591
1994	3,151,852.88	1,867,473	1,385,832	1,766,021	8.15	216,690
1995	3,585,615.46	2,081,450	1,544,622	2,040,993	8.39	243,265
1996	3,253,035.73	1,847,724	1,371,177	1,881,859	8.64	217,808
1997	3,094,865.58	1,719,198	1,275,799	1,819,067	8.89	204,619
1998	3,528,466.19	1,914,193	1,420,503	2,107,963	9.15	230,378
1999	4,970,652.48	2,629,475	1,951,306	3,019,346	9.42	320,525
2000	4,289,940.46	2,211,464	1,641,104	2,648,836	9.69	273,358
2001	4,020,771.19	2,014,406	1,494,870	2,525,901	9.98	253,096
2002	4,314,990.54	2,099,243	1,557,826	2,757,165	10.27	268,468
2003	4,083,667.78	1,925,449	1,428,856	2,654,812	10.57	251,165
2004	4,717,710.25	2,151,276	1,596,439	3,121,271	10.88	286,882
2005	4,937,153.80	2,174,816	1,613,908	3,323,246	11.19	296,984
2006	6,010,670.26	2,548,524	1,891,233	4,119,437	11.52	357,590
2007	7,102,179.99	2,894,138	2,147,709	4,954,471	11.85	418,099
2008	8,012,236.48	3,124,772	2,318,861	5,693,375	12.20	466,670
2009	5,601,923.62	2,086,717	1,548,531	4,053,393	12.55	322,980
2010	6,477,907.58	2,296,418	1,704,148	4,773,760	12.91	369,772
2011	8,633,474.47	2,896,531	2,149,485	6,483,989	13.29	487,885
2012	12,521,036.77	3,956,648	2,936,187	9,584,850	13.68	700,647
2013	12,530,515.74	3,702,767	2,747,785	9,782,731	14.09	694,303
2014	10,603,278.03	2,899,997	2,152,057	8,451,221	14.53	581,639
2015	20,927,128.87	5,231,782	3,882,451	17,044,678	15.00	1,136,312
2016	14,328,314.44	3,216,707	2,387,084	11,941,230	15.51	769,905
2017	21,223,133.65	4,170,346	3,094,770	18,128,364	16.07	1,128,087
2018	7,876,473.18	1,311,433	973,201	6,903,272	16.67	414,113
2019	12,647,907.93	1,701,144	1,262,401	11,385,507	17.31	657,742
2020	10,657,010.95	1,065,701	790,846	9,866,165	18.00	548,120
2021	22,074,179.25	1,379,636	1,023,813	21,050,366	18.75	1,122,686
2022	73,418,062.06	1,615,197	1,198,621	72,219,441	19.56	3,692,200
	365,421,420.67	110,567,919	82,051,298	283,370,123		21,728,635

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0 5.95

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. 0						
1953	167,143.04	157,114	151,601	15,542	2.28	6,817
1954	17,412.70	16,231	15,661	1,752	2.58	679
1955	35,699.80	32,994	31,836	3,864	2.88	1,342
1956	47,076.05	43,137	41,623	5,453	3.18	1,715
1957	70,185.49	63,776	61,538	8,647	3.47	2,492
1958	76,006.39	68,466	66,063	9,943	3.77	2,637
1959	83,507.43	74,541	71,925	11,582	4.08	2,839
1960	114,528.54	101,328	97,772	16,757	4.38	3,826
1961	182,670.92	160,078	154,461	28,210	4.70	6,002
1962	223,609.81	194,129	187,317	36,293	5.01	7,244
1963	203,368.74	174,789	168,656	34,713	5.34	6,501
1964	204,020.98	173,579	167,488	36,533	5.67	6,443
1965	223,877.47	188,529	181,913	41,964	6.00	6,994
1966	245,002.78	204,127	196,964	48,039	6.34	7,577
1967	204,841.34	168,779	162,856	41,985	6.69	6,276
1968	183,908.57	149,788	144,532	39,377	7.05	5,585
1969	184,145.52	148,237	143,035	41,111	7.41	5,548
1970	184,542.93	146,760	141,610	42,933	7.78	5,518
1971	348,796.05	273,990	264,376	84,420	8.15	10,358
1972	367,441.66	284,962	274,963	92,479	8.53	10,842
1973	403,985.03	309,154	298,306	105,679	8.92	11,847
1974	294,808.15	222,504	214,696	80,112	9.32	8,596
1975	221,475.94	164,825	159,041	62,435	9.72	6,423
1976	202,436.84	148,471	143,261	59,176	10.13	5,842
1977	343,076.50	247,828	239,132	103,944	10.55	9,853
1978	1,127,295.66	801,564	773,437	353,859	10.98	32,228
1979	877,776.35	614,215	592,662	285,114	11.41	24,988
1980	408,229.22	280,817	270,963	137,266	11.86	11,574
1981	378,051.23	255,582	246,614	131,437	12.31	10,677
1982	2,188,448.75	1,453,021	1,402,034	786,415	12.77	61,583
1983	2,468,594.61	1,608,487	1,552,044	916,551	13.24	69,226
1984	3,030,631.93	1,937,210	1,869,232	1,161,400	13.71	84,712
1985	3,035,712.53	1,901,327	1,834,609	1,201,104	14.20	84,585
1986	3,883,863.39	2,382,439	2,298,838	1,585,025	14.69	107,898
1987	4,454,462.30	2,672,677	2,578,891	1,875,571	15.20	123,393
1988	4,472,063.36	2,623,223	2,531,173	1,940,890	15.71	123,545
1989	4,206,746.80	2,410,003	2,325,435	1,881,312	16.23	115,916
1990	5,975,217.54	3,338,235	3,221,095	2,754,123	16.77	164,229
1991	6,428,704.33	3,500,237	3,377,412	3,051,292	17.31	176,273
1992	7,161,759.65	3,795,733	3,662,539	3,499,221	17.86	195,925
1993	7,155,081.78	3,686,727	3,557,358	3,597,724	18.42	195,316

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. 0						
1994	5,520,948.74	2,763,400	2,666,431	2,854,518	18.98	150,396
1995	6,654,839.23	3,229,327	3,116,008	3,538,831	19.56	180,922
1996	5,567,760.79	2,615,400	2,523,624	3,044,137	20.15	151,074
1997	5,028,567.29	2,284,026	2,203,878	2,824,689	20.74	136,195
1998	5,612,195.05	2,460,499	2,374,159	3,238,036	21.34	151,736
1999	8,133,209.78	3,433,109	3,312,640	4,820,570	21.96	219,516
2000	6,445,858.15	2,615,665	2,523,880	3,921,978	22.58	173,693
2001	6,444,255.03	2,509,844	2,421,772	4,022,483	23.20	173,383
2002	7,072,547.59	2,635,443	2,542,964	4,529,584	23.84	189,999
2003	6,852,004.24	2,437,875	2,352,329	4,499,675	24.48	183,810
2004	7,363,757.68	2,493,957	2,406,443	4,957,315	25.13	197,267
2005	9,395,716.79	3,021,475	2,915,450	6,480,267	25.78	251,368
2006	9,632,569.48	2,930,324	2,827,498	6,805,071	26.44	257,378
2007	22,612,710.50	6,480,351	6,252,952	16,359,758	27.11	603,458
2008	33,744,136.33	9,075,485	8,757,022	24,987,114	27.78	899,464
2009	36,188,750.27	9,094,957	8,775,811	27,412,939	28.45	963,548
2010	11,770,418.36	2,747,451	2,651,042	9,119,376	29.13	313,058
2011	2,974,695.06	641,136	618,638	2,356,057	29.81	79,036
2012	22,785,496.44	4,497,173	4,339,365	18,446,131	30.50	604,791
2013	20,307,011.38	3,639,220	3,511,518	16,795,493	31.19	538,490
2014	14,309,689.48	2,300,855	2,220,117	12,089,572	31.89	379,102
2015	18,671,073.70	2,658,201	2,564,923	16,106,151	32.59	494,205
2016	19,203,679.94	2,380,296	2,296,770	16,906,910	33.29	507,868
2017	17,359,950.08	1,827,308	1,763,187	15,596,763	34.00	458,728
2018	19,661,794.44	1,702,318	1,642,583	18,019,211	34.71	519,136
2019	20,251,077.29	1,369,580	1,321,521	18,929,556	35.43	534,280
2020	23,479,207.10	1,136,863	1,096,970	22,382,237	36.16	618,978
2021	24,181,051.14	706,329	681,544	23,499,507	36.89	637,016
2022	39,672,809.47	386,413	372,853	39,299,956	37.63	1,044,378
	498,983,988.92	123,253,893	118,928,854	380,055,135		13,344,137

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.5 2.67

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS - DISTRIBUTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2003	7,589,830.51	2,303,134	2,439,736	5,150,095	38.31	134,432
2004	187,177.00	54,077	57,284	129,893	39.11	3,321
2008	14,500.04	3,327	3,524	10,976	42.38	259
2010	147,569.68	29,380	31,123	116,447	44.05	2,644
2011	32,674.59	6,006	6,362	26,313	44.89	586
2012	31,528.80	5,303	5,618	25,911	45.75	566
2013	1,635,016.20	249,716	264,527	1,370,489	46.60	29,410
2014	1,420,452.17	194,730	206,280	1,214,172	47.46	25,583
2015	2,191,394.63	265,750	281,512	1,909,883	48.33	39,518
2016	225,934.75	23,825	25,238	200,697	49.20	4,079
2017	9,701,609.72	867,809	919,280	8,782,330	50.08	175,366
2018	8,483,052.79	621,553	658,418	7,824,635	50.97	153,515
2019	871,745.25	49,925	52,886	818,859	51.85	15,793
2021	1,251,096.79	30,714	32,535	1,218,562	53.65	22,713
2022	277,125.71	2,267	2,402	274,724	54.55	5,036
	34,060,708.63	4,707,516	4,986,725	29,073,984		612,821
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.4						1.80

COMMON PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMMON PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PARK PLAZA						
INTERIM SURVIVOR CURVE.. IOWA 55-R2						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. 0						
1999	7,739,634.08	4,306,952	4,249,034	3,490,600	17.00	205,329
2000	101,850.00	55,587	54,839	47,011	17.07	2,754
2001	2,305,761.82	1,232,130	1,215,561	1,090,201	17.14	63,606
2002	1,831,013.44	956,412	943,551	887,463	17.21	51,567
2003	3,954,373.89	2,016,454	1,989,337	1,965,036	17.27	113,783
2005	61,205.10	29,556	29,159	32,047	17.39	1,843
2006	97,391.77	45,578	44,965	52,427	17.45	3,004
2007	299,539.90	135,575	133,752	165,788	17.50	9,474
2008	422,954.67	184,510	182,029	240,926	17.55	13,728
2009	73,762.13	30,889	30,474	43,289	17.60	2,460
2010	1,926,566.50	771,416	761,042	1,165,524	17.64	66,073
2011	4,123,166.98	1,568,411	1,547,320	2,575,847	17.69	145,610
2012	234,764.39	84,391	83,256	151,508	17.73	8,545
2013	3,064,569.05	1,031,810	1,017,935	2,046,634	17.77	115,174
2014	135,579.58	42,350	41,780	93,799	17.81	5,267
2015	3,144,307.40	900,530	888,420	2,255,887	17.84	126,451
2016	3,164,537.76	816,736	805,753	2,358,785	17.88	131,923
2017	1,366,703.27	311,171	306,986	1,059,717	17.91	59,169
2018	3,411,077.78	663,216	654,297	2,756,780	17.94	153,667
2019	2,783,263.53	438,225	432,332	2,350,932	17.98	130,753
2020	41,814.12	4,955	4,888	36,926	18.00	2,051
2021	168,141.85	12,516	12,348	155,794	18.03	8,641
2022	1,590,368.27	41,175	40,621	1,549,747	18.06	85,811
	42,042,347.28	15,680,545	15,469,678	26,572,669		1,506,683
LEASEHOLD IMPROVEMENTS						
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2013	448,419.39	68,487	448,419			
2015	1,406,396.41	170,554	1,205,360	201,036	48.33	4,160
2016	1,124,695.45	118,599	838,178	286,518	49.20	5,824
2017	780,839.96	69,846	493,624	287,216	50.08	5,735
2018	1,589,424.75	116,457	823,039	766,385	50.97	15,036

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMMON PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LEASEHOLD IMPROVEMENTS						
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2019	20,577,201.01	1,178,456	8,328,531	12,248,670	51.85	236,233
2020	1,458,885.06	59,683	421,799	1,037,086	52.75	19,660
2021	2,012,078.67	49,397	349,105	1,662,974	53.65	30,997
	29,397,940.70	1,831,479	12,908,055	16,489,885		317,645
	71,440,287.98	17,512,024	28,377,734	43,062,554		1,824,328
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					23.6	2.55

GAS PLANT

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 304.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1975	41,238.98	29,917	71,265	30,026-		
	41,238.98	29,917	71,265	30,026-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 305.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1.5						
NET SALVAGE PERCENT.. 0						
1975	1,923,020.00	1,500,456	1,923,020			
1976	53,326.00	41,103	53,326			
1977	567,289.80	431,889	567,290			
1978	504,296.08	378,888	504,296			
1979	89,442.31	66,281	89,442			
1980	268,327.24	196,021	268,327			
1982	55,095.23	39,031	55,095			
1983	136,041.07	94,763	136,041			
1984	47,332.38	32,410	47,332			
1985	139,639.84	93,890	139,640			
1986	172,412.66	113,701	172,413			
1989	21,873.00	13,544	21,873			
1990	275,794.39	166,856	275,794			
1991	13,913.00	8,216	13,913			
1992	69,005.00	39,732	69,005			
1996	1,265,505.00	649,065	1,265,505			
1998	2,747,021.00	1,317,856	2,747,021			
2022	8,778.00	95	1,733,385	1,724,607-		
	8,358,112.00	5,183,797	10,082,718	1,724,606-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 307.00 OTHER POWER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R2						
NET SALVAGE PERCENT.. 0						
1975	41,202.00	39,466	41,202			
1977	87,427.19	81,994	87,427			
1978	64,117.35	59,469	64,117			
1979	5,927.45	5,436	5,927			
1980	27,326.29	24,779	27,326			
1981	25,861.87	23,183	25,862			
1992	2,357,841.00	1,800,377	2,357,841			
1993	16,893.00	12,634	16,893			
1994	87,538.00	64,059	87,538			
2018	54,773.13	7,805	54,773			
2019	28,736.61	3,202	28,737			
2020	30,256.14	2,420	30,256			
2021	1,522.48	73	1,522			
2022	48,486.56	779	152,505	104,018-		
	2,877,909.07	2,125,676	2,981,926	104,017-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S3						
NET SALVAGE PERCENT.. 0						
1921	23,390.50	23,390	23,390			
1942	20,577.24	19,528	20,577			
1947	42,882.96	40,001	42,883			
1948	262,642.89	244,048	262,643			
1949	30,316.59	28,067	30,317			
1952	5,650.00	5,166	5,650			
1954	193,918.07	175,767	193,918			
1955	61,233.82	55,245	61,234			
1956	1,577,707.38	1,416,781	1,577,707			
1958	75,109.61	66,772	75,110			
1959	514,400.30	454,833	514,400			
1960	54,412.49	47,850	54,412			
1961	19,548.48	17,093	19,548			
1970	11,560.65	9,487	11,561			
1971	22,601.05	18,388	22,601			
1972	405,115.00	326,604	405,115			
1973	2,006,356.36	1,602,276	2,006,356			
1974	113,282.81	89,561	113,283			
1975	2,987,223.76	2,337,204	2,987,224			
1976	156,481.88	121,086	156,482			
1977	202,805.24	155,105	202,805			
1978	59,390.30	44,863	59,390			
1979	29,622.00	22,092	29,622			
1980	176,392.00	129,789	176,392			
1981	244,938.00	177,678	244,938			
1982	273,045.00	195,063	273,045			
1983	314,004.00	220,808	314,004			
1985	453,981.00	308,435	453,981			
1986	493,056.00	328,770	493,056			
1989	118,713.00	74,338	118,713			
1990	309,507.00	189,356	309,507			
1991	35,904.00	21,435	35,904			
1992	19,081,959.34	11,098,068	19,081,959			
1998	1,792,305.08	861,740	1,792,305			
1999	849,447.00	392,954	849,447			
2001	4,900,742.68	2,085,756	4,900,743			
2007	11,496.00	3,557	11,496			
2015	451,769.91	67,765	451,770			
2016	727,439.00	94,567	727,439			
2017	68,551.85	7,541	68,552			

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 311.00 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S3						
NET SALVAGE PERCENT.. 0						
2018	138,964.00	12,507	138,964			
2019	37,808.81	2,647	37,809			
2021	23,907.45	717	3,014,398	2,990,491-		
	39,380,160.50	23,594,698	42,370,650	2,990,490-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 320.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 21-R1						
NET SALVAGE PERCENT.. 0						
1975	2,510.06	2,510	2,510			
1978	100,965.95	100,966	100,966			
1979	98,099.81	98,100	98,100			
1983	16,302.72	15,604	16,303			
1988	9,696.88	8,575	361,587	351,890-		
	227,575.42	225,755	579,466	351,890-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. 0						
2021	109,823.75	3,588	53,085-	162,909	43.53	3,742
2022	183,810.17	2,002	29,621-	213,431	44.51	4,795
	293,633.92	5,590	82,706-	376,340		8,537

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.1 2.91

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 362.00 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1975	4,687,701.83	3,400,693	4,687,702			
1976	17,049.61	12,180	17,050			
1981	144,410.23	94,681	144,410			
1983	106,143.68	66,909	106,144			
1992	111,177.13	56,317	111,177			
	5,066,482.48	3,630,780	5,066,483			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2.5						
NET SALVAGE PERCENT.. 0						
1976	464,781.33	328,642	436,882	27,899	16.11	1,732
1989	154,637.25	87,047	115,716	38,921	24.04	1,619
1992	215,768.15	112,553	149,623	66,145	26.31	2,514
1993	23,149.79	11,743	15,611	7,539	27.10	278
1999	372,632.00	154,676	205,619	167,013	32.17	5,192
2007	111,515.57	31,184	41,455	70,061	39.62	1,768
2016	395.00	47	62	333	48.50	7
2017	100,438.98	10,044	13,352	87,087	49.50	1,759
2018	1,556,902.48	127,386	169,341	1,387,561	50.50	27,476
2019	72,743.45	4,629	6,154	66,589	51.50	1,293
2021	5,690,469.13	155,179	206,287	5,484,182	53.50	102,508
	8,763,433.13	1,023,130	1,360,102	7,403,331		146,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.7 1.67

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 363.40 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2.5						
NET SALVAGE PERCENT.. 0						
1975	719,609.43	515,240	719,609			
1992	10,970.34	5,723	10,970			
1996	19,220.03	8,890	19,220			
1997	48,006.92	21,455	48,007			
2012	447,960.99	85,359	447,961			
2015	947,544.13	129,037	819,007	128,537	47.51	2,705
2016	222,880.00	26,340	167,182	55,698	48.50	1,148
2017	803,024.59	80,302	509,682	293,343	49.50	5,926
2018	275,692.32	22,557	143,171	132,521	50.50	2,624
2019	622,561.83	39,620	251,471	371,091	51.50	7,206
2021	520,772.12	14,201	90,135	430,637	53.50	8,049
2022	789,944.46	7,181	45,578	744,367	54.50	13,658
	5,428,187.16	955,905	3,271,993	2,156,194		41,316

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.2 0.76

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S2.5						
NET SALVAGE PERCENT.. 0						
1958	6,876.17	5,106	6,876			
1963	6,169.66	4,376	6,170			
1975	14,458,163.97	8,833,938	13,047,397	1,410,767	27.23	51,809
1976	1,883,950.68	1,133,064	1,673,493	210,458	27.90	7,543
1977	1,605,321.06	949,885	1,402,945	202,376	28.58	7,081
1978	283,885.86	165,182	243,968	39,918	29.27	1,364
1980	16,509.85	9,269	13,690	2,820	30.70	92
1981	5,493.00	3,026	4,469	1,024	31.44	33
1982	41,044.46	22,170	32,744	8,300	32.19	258
1983	372,164.60	196,983	290,937	81,228	32.95	2,465
1984	17,611.65	9,125	13,477	4,135	33.73	123
1985	1,031,230.69	522,690	771,994	259,237	34.52	7,510
1986	294,312.89	145,770	215,297	79,016	35.33	2,237
1987	120,581.10	58,309	86,120	34,461	36.15	953
1988	7,358,257.79	3,470,964	5,126,484	2,231,774	36.98	60,351
1989	661,892.48	304,279	449,409	212,483	37.82	5,618
1991	5,347,913.31	2,327,091	3,437,027	1,910,886	39.54	48,328
1992	10,606,616.50	4,482,038	6,619,803	3,986,814	40.42	98,635
1993	2,815,165.46	1,153,824	1,704,155	1,111,010	41.31	26,894
1994	125,501.81	49,842	73,615	51,887	42.20	1,230
1995	2,712,579.62	1,042,010	1,539,010	1,173,570	43.11	27,223
1996	2,059,999.19	764,260	1,128,783	931,216	44.03	21,150
1998	1,826,870.11	629,485	929,726	897,144	45.88	19,554
1999	145,035.54	48,027	70,934	74,102	46.82	1,583
2001	5,081,720.99	1,544,132	2,280,625	2,801,096	48.73	57,482
2002	138,949.24	40,315	59,544	79,405	49.69	1,598
2005	13,803,410.23	3,431,114	5,067,627	8,735,783	52.60	166,080
2006	5,601,638.91	1,313,976	1,940,693	3,660,946	53.58	68,327
2007	27,720.77	6,114	9,030	18,691	54.56	343
2008	80,233.84	16,574	24,479	55,755	55.54	1,004
2009	472,872.37	90,995	134,396	338,476	56.53	5,988
2010	53,383.98	9,518	14,058	39,326	57.52	684
2011	29,633.75	4,860	7,178	22,456	58.52	384
2012	107,292.03	16,079	23,748	83,544	59.51	1,404
2015	852,259.68	91,311	134,863	717,397	62.50	11,478
2017	8,923,916.33	701,152	1,035,576	7,888,340	64.50	122,300
2018	2,520,677.56	162,054	239,348	2,281,330	65.50	34,829
2019	1,727,301.10	86,365	127,558	1,599,743	66.50	24,056

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-S2.5						
NET SALVAGE PERCENT.. 0						
2020	532,500.13	19,016	28,085	504,415	67.50	7,473
2021	30,185.61	647	956	29,230	68.50	427
2022	2.73		0	3	69.50	
	93,786,846.70	33,864,935	50,016,287	43,770,560		895,891
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					48.9	0.96

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 369.00 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S2.5						
NET SALVAGE PERCENT.. 0						
1990	1,138.63	915	114	1,025	5.88	174
1991	3,058,825.72	2,424,639	301,486	2,757,340	6.22	443,302
1992	424,972.31	331,763	41,252	383,720	6.58	58,316
1993	646,889.50	496,811	61,775	585,114	6.96	84,068
1994	9.00	7	1	8	7.36	1
1995	853.35	632	79	774	7.79	99
1996	14,225.45	10,318	1,283	12,942	8.24	1,571
1997	77,206.16	54,765	6,809	70,397	8.72	8,073
2021	112,292.12	5,615	698	111,594	28.50	3,916
2022	8.22		0	8	29.50	
	4,336,420.46	3,325,465	413,497	3,922,923		599,520

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 13.83

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 374.30 SIDEWALKS AND CURBS - ON PUBLIC PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1997	54,865.26	23,682	29,301	25,565	31.26	818
	54,865.26	23,682	29,301	25,565		818

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.3 1.49

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-S2.5						
NET SALVAGE PERCENT.. 0						
1957	17,840.42	14,391	17,840			
1964	110,484.14	84,502	110,484			
1966	58,465.83	43,918	58,466			
1968	44,816.42	33,015	44,816			
1970	14,286.39	10,308	14,286			
1975	6,459,306.18	4,385,869	6,098,922	360,384	19.26	18,712
1976	1,238,235.48	829,209	1,153,085	85,150	19.82	4,296
1977	487,734.81	321,988	447,752	39,983	20.39	1,961
1978	3,544,983.95	2,306,012	3,206,705	338,279	20.97	16,132
1979	305,342.17	195,520	271,887	33,455	21.58	1,550
1980	480,784.30	302,894	421,200	59,584	22.20	2,684
1981	314,639.40	194,919	271,051	43,588	22.83	1,909
1982	795,439.01	484,160	673,266	122,173	23.48	5,203
1983	4,336,153.27	2,590,852	3,602,799	733,354	24.15	30,367
1984	560,341.28	328,360	456,612	103,729	24.84	4,176
1985	679,410.16	390,206	542,615	136,795	25.54	5,356
1986	841,472.48	473,185	658,004	183,468	26.26	6,987
1987	502,731.49	276,502	384,499	118,232	27.00	4,379
1988	486,309.83	261,392	363,488	122,822	27.75	4,426
1989	3,390,409.21	1,778,846	2,473,636	916,773	28.52	32,145
1990	626,988.29	320,705	445,967	181,021	29.31	6,176
1991	2,516,567.22	1,253,678	1,743,345	773,222	30.11	25,680
1992	6,700,718.06	3,247,637	4,516,115	2,184,603	30.92	70,653
1993	3,265,776.06	1,537,625	2,138,198	1,127,578	31.75	35,514
1994	786,387.46	359,120	499,387	287,000	32.60	8,804
1995	701,836.38	310,443	431,697	270,139	33.46	8,073
1996	410,598.88	175,667	244,280	166,319	34.33	4,845
1997	2,127,962.63	879,210	1,222,616	905,347	35.21	25,713
1998	2,544,550.78	1,013,164	1,408,890	1,135,661	36.11	31,450
1999	103,142.28	39,503	54,932	48,210	37.02	1,302
2003	1,111,866.00	356,909	496,312	615,554	40.74	15,109
2006	727,121.09	198,504	276,037	451,084	43.62	10,341
2007	4,020.00	1,032	1,435	2,585	44.59	58
2010	20,335.39	4,223	5,872	14,463	47.54	304
2017	7,813,799.79	716,291	996,063	6,817,737	54.50	125,096
2018	41,014,317.89	3,076,074	4,277,543	36,736,775	55.50	661,924
2019	176,302.80	10,284	14,301	162,002	56.50	2,867

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-S2.5						
NET SALVAGE PERCENT.. 0						
2020	587,208.84	24,469	34,026	553,183	57.50	9,621
2021	4,603,404.75	115,085	160,035	4,443,370	58.50	75,955
2022	2,577,121.48	21,467	29,852	2,547,270	59.50	42,811
	103,089,212.29	28,967,138	40,268,316	62,820,896		1,302,579
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					48.2	1.26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1923	552,332.82	480,750	552,333			
1924	1,236,888.33	1,072,630	1,236,888			
1925	1,251,701.48	1,081,132	1,251,701			
1926	1,357,018.12	1,167,578	1,357,018			
1927	1,326,187.43	1,136,277	1,326,187			
1928	1,174,974.21	1,002,488	1,174,974			
1929	1,086,406.53	923,011	1,086,407			
1930	700,389.77	592,439	700,390			
1931	531,308.88	447,431	531,309			
1932	288,974.10	242,198	288,974			
1933	120,381.36	100,414	120,381			
1934	193,665.92	160,743	193,666			
1935	133,368.25	110,126	133,368			
1936	255,047.43	209,514	255,047			
1937	337,262.01	275,519	337,262			
1938	445,802.80	362,112	445,803			
1939	594,133.82	479,745	594,134			
1940	772,954.13	620,427	772,954			
1941	672,606.13	536,471	672,606			
1942	395,821.00	313,649	395,821			
1943	393,885.31	310,015	393,885			
1944	188,446.99	147,266	188,447			
1945	193,621.91	150,225	193,622			
1946	614,567.18	473,217	614,567			
1947	2,102,447.68	1,606,543	2,098,104	4,344	17.69	246
1948	4,249,577.14	3,221,179	4,206,777	42,800	18.15	2,358
1949	3,166,438.75	2,380,307	3,108,620	57,819	18.62	3,105
1950	1,529,705.46	1,139,937	1,488,728	40,977	19.11	2,144
1951	5,565,178.54	4,110,830	5,368,638	196,541	19.60	10,028
1952	7,292,113.68	5,337,827	6,971,064	321,050	20.10	15,973
1953	13,941,446.61	10,108,525	13,201,473	739,974	20.62	35,886
1954	18,808,547.11	13,504,537	17,636,577	1,171,970	21.15	55,412
1955	8,516,381.55	6,053,444	7,905,642	610,740	21.69	28,158
1956	9,394,235.38	6,608,563	8,630,613	763,622	22.24	34,336
1957	8,472,082.44	5,896,569	7,700,767	771,315	22.80	33,830
1958	8,094,972.97	5,572,579	7,277,644	817,329	23.37	34,973
1959	8,323,775.82	5,665,744	7,399,315	924,461	23.95	38,600
1960	9,288,782.02	6,249,493	8,161,677	1,127,105	24.54	45,929
1961	8,605,052.18	5,720,639	7,471,007	1,134,045	25.14	45,109
1962	9,676,500.96	6,354,268	8,298,510	1,377,991	25.75	53,514
1963	10,279,036.37	6,664,927	8,704,223	1,574,813	26.37	59,720

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
1964	9,590,001.23	6,137,601	8,015,549	1,574,452	27.00	58,313
1965	9,450,721.95	5,967,847	7,793,854	1,656,868	27.64	59,945
1966	9,502,214.13	5,917,979	7,728,728	1,773,486	28.29	62,690
1967	9,579,149.18	5,881,598	7,681,215	1,897,934	28.95	65,559
1968	12,919,795.51	7,819,060	10,211,491	2,708,305	29.61	91,466
1969	11,720,155.92	6,988,377	9,126,640	2,593,516	30.28	85,651
1970	10,873,208.01	6,384,748	8,338,316	2,534,892	30.96	81,876
1971	9,813,763.33	5,672,355	7,407,949	2,405,814	31.65	76,013
1972	11,109,133.31	6,317,431	8,250,402	2,858,731	32.35	88,369
1973	10,805,034.97	6,043,580	7,892,760	2,912,275	33.05	88,117
1974	8,322,618.54	4,576,358	5,976,605	2,346,014	33.76	69,491
1975	6,277,281.51	3,391,427	4,429,116	1,848,166	34.48	53,601
1976	7,158,773.73	3,797,944	4,960,017	2,198,757	35.21	62,447
1977	9,059,268.67	4,718,067	6,161,674	2,897,595	35.94	80,623
1978	12,385,288.01	6,328,015	8,264,224	4,121,064	36.68	112,352
1979	19,735,764.71	9,886,237	12,911,170	6,824,595	37.43	182,330
1980	23,231,669.20	11,405,123	14,894,796	8,336,873	38.18	218,357
1981	24,375,924.59	11,719,945	15,305,946	9,069,979	38.94	232,922
1982	25,892,113.63	12,186,641	15,915,439	9,976,675	39.70	251,302
1983	28,756,916.26	13,235,946	17,285,804	11,471,112	40.48	283,377
1984	30,787,614.36	13,850,424	18,088,296	12,699,318	41.26	307,788
1985	40,125,409.11	17,633,914	23,029,437	17,095,972	42.04	406,660
1986	47,251,341.62	20,267,518	26,468,856	20,782,486	42.83	485,232
1987	50,738,040.59	21,222,200	27,715,646	23,022,395	43.63	527,674
1988	53,616,351.07	21,854,025	28,540,793	25,075,558	44.43	564,383
1989	47,344,639.19	18,786,353	24,534,492	22,810,147	45.24	504,203
1990	51,465,298.62	19,865,605	25,943,967	25,521,332	46.05	554,209
1991	48,047,986.42	18,021,358	23,535,429	24,512,557	46.87	522,990
1992	44,858,594.86	16,328,529	21,324,638	23,533,957	47.70	493,374
1993	54,104,482.03	19,095,095	24,937,701	29,166,781	48.53	601,005
1994	49,747,721.63	17,000,289	22,201,939	27,545,783	49.37	557,946
1995	51,003,159.16	16,858,074	22,016,210	28,986,949	50.21	577,314
1996	40,217,236.19	12,842,570	16,772,065	23,445,171	51.05	459,259
1997	45,701,055.90	14,069,984	18,375,036	27,326,020	51.91	526,411
1998	51,767,800.36	15,350,706	20,047,626	31,720,174	52.76	601,216
1999	59,100,342.20	16,847,735	22,002,707	37,097,635	53.62	691,862
2000	64,964,838.09	17,765,934	23,201,851	41,762,987	54.49	766,434
2001	62,587,179.86	16,389,705	21,404,532	41,182,648	55.36	743,906
2002	63,949,635.51	15,995,722	20,890,000	43,059,636	56.24	765,641
2003	58,323,077.98	13,911,804	18,168,457	40,154,621	57.11	703,110
2004	65,847,665.96	14,925,690	19,492,566	46,355,100	58.00	799,226

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2.5						
NET SALVAGE PERCENT.. 0						
2005	82,997,741.85	17,827,915	23,282,797	59,714,945	58.89	1,014,008
2006	79,819,488.28	16,197,769	21,153,868	58,665,620	59.78	981,359
2007	66,149,375.41	12,629,900	16,494,323	49,655,052	60.68	818,310
2008	92,320,658.80	16,518,935	21,573,303	70,747,356	61.58	1,148,869
2009	106,384,867.58	17,758,826	23,192,569	83,192,299	62.48	1,331,503
2010	155,252,293.86	24,033,055	31,386,550	123,865,744	63.39	1,954,027
2011	78,746,023.22	11,234,695	14,672,222	64,073,801	64.30	996,482
2012	54,535,261.54	7,118,488	9,296,562	45,238,700	65.21	693,739
2013	59,858,217.86	7,079,431	9,245,554	50,612,664	66.13	765,351
2014	52,217,915.97	5,535,099	7,228,696	44,989,220	67.05	670,980
2015	91,463,169.06	8,560,953	11,180,384	80,282,785	67.98	1,180,977
2016	108,281,518.06	8,806,536	11,501,109	96,780,409	68.90	1,404,650
2017	182,679,927.67	12,568,379	16,413,978	166,265,950	69.84	2,380,669
2018	170,466,659.06	9,614,320	12,556,054	157,910,605	70.77	2,231,321
2019	197,064,022.74	8,670,817	11,323,863	185,740,160	71.70	2,590,518
2020	269,143,435.14	8,469,944	11,061,528	258,081,907	72.64	3,552,890
2021	218,134,392.01	4,129,284	5,392,738	212,741,654	73.58	2,891,297
2022	199,142,966.25	1,248,626	1,630,674	197,512,293	74.53	2,650,105
	3,768,890,222.03	809,853,773	1,056,277,834	2,712,612,388		44,221,020
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					61.3	1.17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1908	4,010.14	4,010	4,010			
1909	10,572.77	10,573	10,573			
1910	1,838.28	1,838	1,838			
1911	1,580.16	1,580	1,580			
1912	780.01	780	780			
1913	1,681.57	1,682	1,682			
1914	844.54	845	845			
1915	391.73	392	392			
1916	593.36	593	593			
1917	1,736.88	1,737	1,737			
1918	593.36	593	593			
1919	639.46	639	639			
1920	1,216.54	1,217	1,217			
1921	2,407.44	2,407	2,407			
1922	4,189.11	4,189	4,189			
1923	4,626.93	4,627	4,627			
1924	3,027.17	3,027	3,027			
1925	4,856.22	4,856	4,856			
1926	7,663.31	7,663	7,663			
1927	8,243.19	8,243	8,243			
1928	8,772.01	8,772	8,772			
1929	2,862.40	2,862	2,862			
1930	2,666.54	2,667	2,667			
1931	8,010.45	8,010	8,010			
1932	1,135.71	1,136	1,136			
1933	602.58	603	603			
1934	260.40	260	260			
1935	1,700.01	1,700	1,700			
1936	3,418.89	3,419	3,419			
1937	3,054.82	3,055	3,055			
1938	3,280.50	3,280	3,280			
1939	8,215.54	8,198	8,216			
1940	8,285.94	8,230	8,286			
1941	7,089.35	7,022	7,089			
1942	3,871.00	3,822	3,871			
1943	6,832.66	6,721	6,833			
1944	4,370.77	4,283	4,371			
1945	7,158.80	6,984	7,159			
1946	12,720.58	12,360	12,721			
1947	29,694.79	28,734	29,695			
1948	54,453.28	52,453	54,453			

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1949	57,092.17	54,746	57,092			
1950	53,736.96	51,284	53,737			
1951	97,578.62	92,682	97,579			
1952	113,311.94	107,090	113,312			
1953	43,460.12	40,876	43,460			
1954	159,331.61	149,077	159,332			
1955	156,438.18	145,602	156,438			
1956	160,866.43	148,933	160,866			
1957	136,758.94	125,918	136,759			
1958	42,781.90	39,173	42,597	185	4.64	40
1959	199,592.93	181,701	197,585	2,008	4.93	407
1960	242,393.85	219,345	238,520	3,874	5.23	741
1961	29,838.35	26,827	29,172	666	5.55	120
1962	161,864.44	144,560	157,197	4,667	5.88	794
1963	93,471.43	82,901	90,148	3,323	6.22	534
1964	67,663.17	59,556	64,762	2,901	6.59	440
1965	42,434.60	37,057	40,296	2,139	6.97	307
1966	38,985.19	33,754	36,705	2,280	7.38	309
1967	48,766.38	41,833	45,490	3,276	7.82	419
1968	61,455.43	52,192	56,754	4,701	8.29	567
1969	71,360.33	59,968	65,210	6,150	8.78	700
1970	114,548.92	95,159	103,478	11,071	9.31	1,189
1971	101,341.13	83,174	90,445	10,896	9.86	1,105
1972	171,579.98	139,011	151,163	20,417	10.44	1,956
1973	74,498.65	59,531	64,735	9,764	11.05	884
1974	112,411.69	88,540	96,280	16,132	11.68	1,381
1975	60,062.06	46,587	50,660	9,402	12.34	762
1976	28,884.25	22,057	23,985	4,899	13.00	377
1977	155,847.79	117,084	127,319	28,529	13.68	2,085
1978	52,190.18	38,545	41,915	10,275	14.38	715
1979	74,990.26	54,429	59,187	15,803	15.08	1,048
1980	131,989.21	94,073	102,297	29,692	15.80	1,879
1981	581,056.99	406,420	441,948	139,109	16.53	8,416
1982	888,299.12	609,213	662,469	225,830	17.28	13,069
1983	917,542.40	616,588	670,489	247,053	18.04	13,695
1984	559,716.21	368,293	400,488	159,228	18.81	8,465
1985	1,007,816.25	648,671	705,376	302,440	19.60	15,431
1986	1,140,524.99	717,493	780,214	360,311	20.40	17,662
1987	974,749.23	598,847	651,197	323,552	21.21	15,255
1988	1,656,052.55	992,423	1,079,178	576,875	22.04	26,174
1989	2,698,353.24	1,575,838	1,713,594	984,759	22.88	43,040

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1990	3,169,465.62	1,802,000	1,959,526	1,209,940	23.73	50,988
1991	2,729,712.32	1,508,794	1,640,689	1,089,023	24.60	44,269
1992	2,753,114.25	1,478,175	1,607,393	1,145,721	25.47	44,983
1993	2,705,977.56	1,409,084	1,532,262	1,173,716	26.36	44,526
1994	3,275,305.75	1,652,556	1,797,018	1,478,288	27.25	54,249
1995	1,102,076.15	537,813	584,827	517,249	28.16	18,368
1996	888,188.42	418,577	455,168	433,020	29.08	14,891
1997	1,691,659.47	768,944	836,163	855,496	30.00	28,517
1998	310,081.73	135,704	147,567	162,515	30.93	5,254
1999	223,646.56	94,055	102,277	121,370	31.87	3,808
2000	95,622.96	38,562	41,933	53,690	32.82	1,636
2001	517,408.94	199,720	217,179	300,230	33.77	8,890
2002	2,172,245.54	800,581	870,566	1,301,680	34.73	37,480
2003	960,092.77	336,906	366,357	593,736	35.70	16,631
2004	2,700,063.29	899,850	978,513	1,721,550	36.67	46,947
2005	3,247,082.95	1,024,909	1,114,504	2,132,579	37.64	56,657
2006	2,925,679.92	871,326	947,495	1,978,185	38.62	51,222
2007	6,531,044.43	1,828,692	1,988,551	4,542,493	39.60	114,709
2008	4,263,142.98	1,117,711	1,215,418	3,047,725	40.58	75,104
2009	5,925,596.61	1,447,979	1,574,558	4,351,039	41.56	104,693
2010	11,144,765.21	2,522,729	2,743,259	8,401,506	42.55	197,450
2011	5,279,092.20	1,099,952	1,196,107	4,082,985	43.54	93,775
2012	2,422,293.33	461,108	501,417	1,920,876	44.53	43,137
2013	2,195,191.75	377,968	411,009	1,784,183	45.53	39,187
2015	4,779,052.38	649,951	706,768	4,072,284	47.52	85,696
2016	4,275,352.58	504,492	548,593	3,726,760	48.51	76,825
2017	8,757,653.75	874,189	950,608	7,807,046	49.51	157,686
2018	1,817,243.33	148,360	161,329	1,655,914	50.51	32,784
2019	3,627,167.79	230,833	251,012	3,376,156	51.50	65,556
2020	10,100,457.63	459,066	499,197	9,601,261	52.50	182,881
2021	15,080,252.65	411,238	447,187	14,633,066	53.50	273,515
2022	23,565,585.81	214,211	232,937	23,332,649	54.50	428,122
	155,052,903.89	35,829,148	38,926,764	116,126,140		2,680,402

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.3 1.73

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1961	8,832.84	7,484	8,833			
1962	21,431.78	18,014	21,432			
1975	3,948,146.50	2,864,183	3,854,553	93,594	15.10	6,198
1976	1,006,309.82	718,867	967,435	38,875	15.71	2,475
1977	3,018,771.42	2,123,011	2,857,100	161,671	16.32	9,906
1978	923,126.96	638,472	859,241	63,886	16.96	3,767
1979	1,312,066.59	891,969	1,200,392	111,675	17.61	6,342
1980	1,769,250.42	1,181,541	1,590,091	179,159	18.27	9,806
1981	1,267,754.42	831,191	1,118,598	149,156	18.94	7,875
1982	1,491,693.07	959,293	1,290,995	200,698	19.63	10,224
1983	1,869,296.95	1,178,330	1,585,770	283,527	20.33	13,946
1984	1,781,179.23	1,099,789	1,480,071	301,108	21.04	14,311
1985	1,022,424.83	617,729	831,326	191,099	21.77	8,778
1986	6,290,064.18	3,716,862	5,002,069	1,287,995	22.50	57,244
1987	2,769,885.32	1,598,972	2,151,861	618,024	23.25	26,582
1988	607,167.90	342,109	460,403	146,765	24.01	6,113
1989	5,983,829.22	3,288,952	4,426,198	1,557,631	24.77	62,884
1990	1,159,045.72	620,611	835,204	323,842	25.55	12,675
1991	996,176.17	519,097	698,589	297,587	26.34	11,298
1992	2,683,077.27	1,359,113	1,829,064	854,013	27.14	31,467
1993	3,209,295.55	1,578,973	2,124,946	1,084,350	27.94	38,810
1994	10,321,644.65	4,924,353	6,627,083	3,694,562	28.76	128,462
1995	3,302,875.53	1,525,928	2,053,560	1,249,316	29.59	42,221
1996	4,299,961.93	1,921,696	2,586,175	1,713,787	30.42	56,338
1997	2,360,100.79	1,018,714	1,370,962	989,139	31.26	31,642
1998	5,728,496.70	2,384,086	3,208,449	2,520,048	32.11	78,482
1999	1,220,869.67	489,019	658,111	562,759	32.97	17,069
2001	175,954.67	64,880	87,314	88,641	34.72	2,553
2002	1,946,228.65	686,493	923,867	1,022,362	35.60	28,718
2003	202,740.81	68,232	91,825	110,916	36.49	3,040
2010	1,449,460.91	318,084	428,070	1,021,391	42.93	23,792
2012	3,551,293.48	657,948	885,452	2,665,841	44.81	59,492
2014	2,871,202.19	432,259	581,724	2,289,478	46.72	49,004
2015	976,467.45	129,782	174,658	801,809	47.69	16,813
2017	3,834,897.20	375,130	504,842	3,330,055	49.62	67,111
2020	16,414,854.21	734,236	988,118	15,426,736	52.54	293,619
2021	814,427.42	21,916	29,494	784,933	53.52	14,666
	102,610,302.42	41,907,318	56,393,875	46,216,427		1,253,723

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.9 1.22

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1947	107,698.54	92,870	107,699			
1948	672,302.46	576,217	672,302			
1949	846,922.39	721,451	846,922			
1950	1,203,070.47	1,018,171	1,203,070			
1951	1,470,932.55	1,236,495	1,470,933			
1952	1,558,184.76	1,300,492	1,558,185			
1954	1,701,967.73	1,399,273	1,701,968			
1955	2,250,282.83	1,835,196	2,250,283			
1956	2,543,205.91	2,056,869	2,543,206			
1957	2,743,519.42	2,199,891	2,743,519			
1958	3,258,074.62	2,588,931	3,245,288	12,787	13.35	958
1959	3,988,840.62	3,139,537	3,935,486	53,355	13.84	3,855
1960	3,679,325.25	2,868,181	3,595,334	83,991	14.33	5,861
1961	3,373,818.79	2,603,036	3,262,969	110,850	14.85	7,465
1962	4,637,791.97	3,540,398	4,437,975	199,817	15.38	12,992
1963	5,147,202.00	3,886,549	4,871,884	275,318	15.92	17,294
1964	5,566,776.18	4,155,376	5,208,865	357,911	16.48	21,718
1965	5,302,416.91	3,911,540	4,903,210	399,207	17.05	23,414
1966	6,221,249.90	4,533,860	5,683,304	537,946	17.63	30,513
1967	6,917,828.28	4,977,654	6,239,610	678,218	18.23	37,203
1968	7,830,461.56	5,560,802	6,970,600	859,862	18.84	45,640
1969	8,477,734.39	5,939,670	7,445,521	1,032,213	19.46	53,043
1970	8,449,870.42	5,836,917	7,316,717	1,133,153	20.10	56,376
1971	4,520,432.11	3,077,375	3,857,564	662,868	20.75	31,945
1972	10,988,431.82	7,369,062	9,237,298	1,751,134	21.41	81,790
1973	10,812,675.80	7,139,718	8,949,810	1,862,866	22.08	84,369
1974	9,863,565.00	6,409,838	8,034,888	1,828,677	22.76	80,346
1975	7,582,234.73	4,846,792	6,075,571	1,506,664	23.45	64,250
1976	2,575,129.34	1,617,980	2,028,177	546,952	24.16	22,639
1977	8,121,045.53	5,013,771	6,284,884	1,836,162	24.87	73,830
1978	14,119,697.16	8,560,914	10,731,313	3,388,384	25.59	132,410
1979	12,115,855.90	7,207,965	9,035,359	3,080,497	26.33	116,996
1980	26,906,273.79	15,700,887	19,681,443	7,224,831	27.07	266,894
1981	22,557,176.47	12,902,705	16,173,854	6,383,322	27.82	229,451
1982	23,454,291.45	13,141,674	16,473,407	6,980,884	28.58	244,258
1983	24,844,496.54	13,626,213	17,080,789	7,763,708	29.35	264,522
1984	30,890,406.85	16,571,468	20,772,737	10,117,670	30.13	335,801
1985	33,908,311.46	17,783,553	22,292,115	11,616,196	30.91	375,807
1986	38,552,749.96	19,744,791	24,750,575	13,802,175	31.71	435,263
1987	39,279,151.42	19,633,684	24,611,299	14,667,852	32.51	451,180
1988	38,075,207.06	18,557,094	23,261,768	14,813,439	33.32	444,581

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1989	38,814,830.74	18,428,117	23,100,092	15,714,739	34.14	460,303
1990	40,674,172.84	18,797,569	23,563,209	17,110,964	34.96	489,444
1991	41,027,971.97	18,430,996	23,103,701	17,924,271	35.80	500,678
1992	44,489,994.98	19,411,430	24,332,699	20,157,296	36.64	550,145
1993	46,809,237.90	19,811,074	24,833,662	21,975,576	37.49	586,172
1994	56,409,477.25	23,136,347	29,001,972	27,407,505	38.34	714,854
1995	48,824,792.56	19,372,213	24,283,539	24,541,254	39.21	625,893
1996	51,501,934.95	19,744,812	24,750,601	26,751,334	40.08	667,448
1997	51,908,775.73	19,206,247	24,075,497	27,833,279	40.95	679,689
1998	60,585,990.94	21,596,482	27,071,714	33,514,277	41.83	801,202
1999	47,023,362.59	16,118,198	20,204,552	26,818,811	42.72	627,781
2000	49,608,263.82	16,317,150	20,453,944	29,154,320	43.62	668,370
2001	47,675,781.53	15,021,685	18,830,047	28,845,735	44.52	647,928
2002	56,426,710.38	16,988,954	21,296,066	35,130,644	45.43	773,292
2003	63,879,773.01	18,338,605	22,987,886	40,891,887	46.34	882,432
2004	60,517,410.97	16,516,412	20,703,723	39,813,688	47.26	842,439
2005	64,788,850.57	16,765,411	21,015,850	43,773,001	48.18	908,531
2006	67,222,554.15	16,433,226	20,599,448	46,623,106	49.11	949,361
2007	66,732,493.30	15,348,473	19,239,683	47,492,810	50.05	948,907
2008	71,167,203.76	15,339,379	19,228,284	51,938,920	50.99	1,018,610
2009	82,773,336.21	16,644,062	20,863,736	61,909,600	51.93	1,192,174
2010	88,647,443.96	16,529,202	20,719,756	67,927,688	52.88	1,284,563
2011	73,245,263.02	12,587,198	15,778,358	57,466,905	53.83	1,067,563
2012	74,616,216.32	11,731,908	14,706,231	59,909,985	54.78	1,093,647
2013	88,010,741.82	12,538,010	15,716,700	72,294,042	55.74	1,296,987
2014	189,039,666.65	24,110,119	30,222,619	158,817,048	56.71	2,800,512
2015	315,532,094.82	35,582,554	44,603,595	270,928,500	57.67	4,697,911
2016	396,260,143.62	38,774,055	48,604,219	347,655,925	58.64	5,928,648
2017	349,579,771.57	28,987,155	36,336,103	313,243,669	59.61	5,254,885
2018	470,613,574.54	31,931,131	40,026,448	430,587,127	60.59	7,106,571
2019	389,520,638.15	20,613,432	25,839,437	363,681,201	61.56	5,907,752
2020	343,189,382.10	12,989,718	16,282,927	326,906,455	62.54	5,227,158
2021	475,102,622.71	10,818,087	13,560,735	461,541,888	63.52	7,266,088
2022	505,465,787.02	3,811,212	4,777,446	500,688,341	64.51	7,761,407
	5,364,802,876.79	903,655,483	1,132,262,180	4,232,540,696		76,282,009
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					55.5	1.42

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1964	17.67	13	10-	28	6.14	5
1965	136.88	103	79-	216	6.26	35
1966	154.56	115	89-	244	6.39	38
1967	922.95	682	526-	1,449	6.52	222
1968	1,077.34	791	610-	1,687	6.65	254
1969	4,409.44	3,212	2,475-	6,884	6.79	1,014
1970	10,316.94	7,453	5,744-	16,061	6.94	2,314
1971	10,146.63	7,269	5,602-	15,749	7.09	2,221
1972	19,444.06	13,805	10,640-	30,084	7.25	4,150
1973	17,765.33	12,500	9,634-	27,399	7.41	3,698
1974	26,268.29	18,304	14,107-	40,375	7.58	5,327
1975	17,575.62	12,127	9,346-	26,922	7.75	3,474
1976	26,470.62	18,074	13,930-	40,401	7.93	5,095
1977	28,173.99	19,034	14,670-	42,844	8.11	5,283
1978	68,270.58	45,605	35,148-	103,419	8.30	12,460
1979	160,918.24	106,270	81,903-	242,821	8.49	28,601
1980	84,481.69	55,116	42,478-	126,960	8.69	14,610
1981	94,255.19	60,738	46,811-	141,066	8.89	15,868
1982	313,940.69	199,666	153,883-	467,824	9.10	51,409
1983	440,093.96	276,203	212,870-	652,964	9.31	70,136
1984	668,724.48	413,807	318,922-	987,646	9.53	103,635
1985	836,003.66	509,962	393,029-	1,229,033	9.75	126,055
1986	965,381.42	580,001	447,008-	1,412,389	9.98	141,522
1987	1,057,706.64	625,316	481,932-	1,539,639	10.22	150,650
1988	970,200.59	564,269	434,883-	1,405,084	10.46	134,329
1989	962,401.49	550,494	424,267-	1,386,668	10.70	129,595
1990	1,388,690.53	780,444	601,490-	1,990,181	10.95	181,752
1991	1,491,484.52	822,703	634,059-	2,125,544	11.21	189,611
1992	1,862,423.36	1,007,944	776,825-	2,639,248	11.47	230,100
1993	1,864,113.58	988,726	762,013-	2,626,127	11.74	223,691
1994	2,067,541.29	1,074,294	827,961-	2,895,502	12.01	241,091
1995	1,995,990.15	1,014,761	782,079-	2,778,069	12.29	226,043
1996	1,580,455.49	785,170	605,132-	2,185,587	12.58	173,735
1997	2,033,275.62	986,545	760,332-	2,793,608	12.87	217,064
1998	2,133,927.76	1,009,775	778,236-	2,912,164	13.17	221,121
1999	3,080,199.64	1,419,356	1,093,901-	4,174,101	13.48	309,651
2000	3,448,646.47	1,546,373	1,191,793-	4,640,439	13.79	336,508
2001	3,580,488.58	1,559,661	1,202,034-	4,782,523	14.11	338,946
2002	3,316,229.97	1,400,776	1,079,581-	4,395,811	14.44	304,419
2003	3,372,484.96	1,380,021	1,063,585-	4,436,070	14.77	300,343
2004	4,771,476.23	1,887,596	1,454,775-	6,226,251	15.11	412,062

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
2005	4,722,991.94	1,802,294	1,389,032-	6,112,024	15.46	395,344
2006	4,687,645.11	1,721,303	1,326,612-	6,014,257	15.82	380,168
2007	4,681,341.77	1,649,705	1,271,431-	5,952,773	16.19	367,682
2008	4,939,196.89	1,667,473	1,285,125-	6,224,322	16.56	375,865
2009	3,292,886.53	1,060,309	817,183-	4,110,070	16.95	242,482
2010	4,591,014.12	1,404,850	1,082,721-	5,673,735	17.35	327,016
2011	5,806,847.25	1,679,340	1,294,271-	7,101,118	17.77	399,613
2012	11,907,667.26	3,234,122	2,492,545-	14,400,212	18.21	790,786
2013	13,507,412.66	3,409,271	2,627,533-	16,134,946	18.69	863,293
2014	13,165,205.54	3,059,594	2,358,036-	15,523,242	19.19	808,924
2015	15,943,422.37	3,360,873	2,590,233-	18,533,655	19.73	939,364
2016	27,700,672.26	5,207,726	4,013,607-	31,714,279	20.30	1,562,280
2017	43,395,153.79	7,099,447	5,471,560-	48,866,714	20.91	2,337,002
2018	51,665,601.87	7,109,187	5,479,067-	57,144,669	21.56	2,650,495
2019	52,312,050.07	5,775,250	4,450,999-	56,763,049	22.24	2,552,295
2020	47,210,793.27	3,852,401	2,969,054-	50,179,847	22.96	2,185,533
2021	63,845,993.02	3,243,376	2,499,677-	66,345,670	23.73	2,795,856
2022	58,899,464.05	1,060,190	817,091-	59,716,555	24.55	2,432,446
	477,048,046.87	79,161,785	61,010,169-	538,058,216		27,324,581

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7 5.73

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1997	43,382.06	21,049	46,501-	89,883	12.87	6,984
1998	357,674.90	169,252	373,906-	731,581	13.17	55,549
1999	682,277.20	314,393	694,547-	1,376,824	13.48	102,138
2000	932,117.61	417,962	923,349-	1,855,467	13.79	134,552
2001	1,132,150.67	493,165	1,089,485-	2,221,636	14.11	157,451
2002	1,057,151.69	446,541	986,484-	2,043,636	14.44	141,526
2003	1,015,605.74	415,586	918,100-	1,933,706	14.77	130,921
2004	1,525,296.73	603,407	1,333,028-	2,858,325	15.11	189,168
2005	2,394,587.86	913,775	2,018,683-	4,413,271	15.46	285,464
2006	2,923,571.69	1,073,536	2,371,622-	5,295,194	15.82	334,715
2007	2,747,852.12	968,343	2,139,233-	4,887,085	16.19	301,858
2008	3,488,541.66	1,177,732	2,601,809-	6,090,351	16.56	367,775
2009	2,148,444.50	691,799	1,528,301-	3,676,746	16.95	216,917
2010	4,057,736.43	1,241,667	2,743,052-	6,800,788	17.35	391,976
2011	3,429,066.55	991,686	2,190,802-	5,619,869	17.77	316,256
2012	167,650.39	45,534	100,592-	268,242	18.21	14,730
2014	11,692,424.40	2,717,319	6,003,016-	17,695,440	19.19	922,118
2015	6,681,385.40	1,408,436	3,111,473-	9,792,858	19.73	496,344
2016	5,690,362.90	1,069,788	2,363,342-	8,053,705	20.30	396,734
2017	90,744.05	14,846	32,797-	123,541	20.91	5,908
2019	250,371.90	27,641	61,064-	311,436	22.24	14,003
2020	123,140.12	10,048	22,197-	145,338	22.96	6,330
	52,631,536.57	15,233,505	33,653,383-	86,284,920		4,989,417

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.3 9.48

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1920	976.82	977	977			
1921	976.82	962	977			
1922	976.82	923	977			
1923	1,465.24	1,384	1,465			
1924	1,953.65	1,846	1,954			
1925	2,442.06	2,271	2,442			
1926	2,930.47	2,727	2,930			
1927	2,930.47	2,719	2,930			
1928	2,442.06	2,258	2,442			
1929	2,442.06	2,247	2,442			
1930	1,953.65	1,790	1,954			
1931	1,465.24	1,336	1,465			
1932	976.82	886	977			
1933	488.41	441	488			
1934	488.41	438	488			
1935	976.82	872	977			
1936	976.82	867	977			
1937	1,465.24	1,294	1,465			
1938	4,395.71	3,859	4,396			
1939	5,860.95	5,115	5,861			
1940	7,814.59	6,780	7,815			
1941	9,279.83	8,003	9,280			
1942	6,837.77	5,861	6,838			
1943	4,395.71	3,745	4,396			
1944	2,442.06	2,067	2,442			
1945	4,395.71	3,698	4,396			
1946	6,837.77	5,716	6,838			
1947	17,094.43	14,195	17,094			
1948	19,048.07	15,718	19,048			
1949	18,071.25	14,818	18,071			
1950	25,885.84	21,102	25,886			
1951	28,816.32	23,353	28,816			
1952	29,793.14	24,001	29,793			
1953	36,630.91	29,349	36,631			
1954	54,939.32	43,776	54,939			
1955	69,042.79	54,737	69,043			
1956	75,513.54	59,565	75,514			
1957	75,138.25	58,968	75,138			
1958	75,152.20	58,649	75,152			
1959	99,193.54	77,014	99,194			
1960	103,173.15	79,691	103,173			

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1961	52,519.59	40,335	52,520			
1962	89,331.59	68,214	89,332			
1963	88,636.00	67,292	88,636			
1964	90,632.97	68,374	90,633			
1965	79,390.81	59,511	79,391			
1966	98,038.09	72,980	98,038			
1967	87,704.87	64,831	87,357	348	6.52	53
1968	100,573.74	73,821	99,471	1,103	6.65	166
1969	113,016.48	82,321	110,925	2,091	6.79	308
1970	117,556.82	84,923	114,431	3,126	6.94	450
1971	95,573.26	68,469	92,260	3,313	7.09	467
1972	197,315.00	140,094	188,772	8,543	7.25	1,178
1973	110,362.62	77,651	104,632	5,731	7.41	773
1974	105,873.61	73,773	99,407	6,467	7.58	853
1975	30,975.93	21,373	28,799	2,177	7.75	281
1976	62,367.96	42,585	57,382	4,986	7.93	629
1977	92,945.74	62,794	84,613	8,333	8.11	1,027
1978	109,224.36	72,962	98,314	10,910	8.30	1,314
1979	264,573.97	174,725	235,436	29,138	8.49	3,432
1980	584,670.38	381,439	513,976	70,694	8.69	8,135
1981	487,792.80	314,334	423,554	64,239	8.89	7,226
1982	260,100.66	165,424	222,903	37,198	9.10	4,088
1983	382,972.07	240,353	323,867	59,105	9.31	6,349
1984	573,564.25	354,922	478,245	95,319	9.53	10,002
1985	744,902.48	454,391	612,276	132,626	9.75	13,603
1986	1,138,295.78	683,888	921,515	216,781	9.98	21,722
1987	1,330,211.59	786,421	1,059,675	270,537	10.22	26,471
1988	918,887.40	534,425	720,119	198,768	10.46	19,003
1989	1,033,289.65	591,042	796,408	236,882	10.70	22,139
1990	1,238,112.45	695,819	937,592	300,520	10.95	27,445
1991	993,578.95	548,058	738,489	255,090	11.21	22,756
1992	1,076,405.98	582,551	784,967	291,439	11.47	25,409
1993	1,219,951.77	647,062	871,893	348,059	11.74	29,647
1994	952,929.76	495,142	667,186	285,744	12.01	23,792
1995	1,130,336.21	574,663	774,338	355,998	12.29	28,966
1996	1,137,464.78	565,093	761,443	376,022	12.58	29,890
1997	1,099,912.32	533,677	719,111	380,801	12.87	29,588
1998	1,098,894.49	519,997	700,678	398,216	13.17	30,237
1999	1,404,869.58	647,364	872,300	532,570	13.48	39,508
2000	1,192,146.55	534,559	720,299	471,848	13.79	34,217
2001	1,341,560.40	584,384	787,437	554,123	14.11	39,272

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
2002	1,427,534.35	602,991	812,509	615,025	14.44	42,592
2003	643,597.16	263,360	354,868	288,729	14.77	19,548
2004	1,747,651.21	691,371	931,598	816,053	15.11	54,007
2005	2,018,328.05	770,194	1,037,809	980,519	15.46	63,423
2006	1,589,481.60	583,658	786,459	803,023	15.82	50,760
2007	1,494,564.83	526,685	709,690	784,875	16.19	48,479
2008	1,538,250.29	519,313	699,756	838,494	16.56	50,634
2009	1,144,465.44	368,518	496,565	647,900	16.95	38,224
2010	908,686.87	278,058	374,673	534,014	17.35	30,779
2011	1,591,465.16	460,252	620,174	971,291	17.77	54,659
2012	259,553.74	70,495	94,989	164,565	18.21	9,037
2016	0.23		0			
	38,499,123.37	18,632,949	25,035,791	13,463,332		972,538
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					13.8	2.53

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1928	356.21	329	356			
1929	514.52	473	515			
1930	461.75	423	462			
1931	411.62	375	412			
1932	369.40	335	369			
1933	269.14	243	269			
1934	332.46	298	332			
1935	459.11	410	459			
1936	680.75	605	681			
1937	1,105.57	976	1,106			
1938	3,905.10	3,429	3,905			
1939	5,836.54	5,094	5,837			
1940	8,219.18	7,131	8,219			
1941	10,765.41	9,284	10,765			
1942	8,704.68	7,462	8,705			
1943	5,701.97	4,858	5,702			
1944	2,960.49	2,506	2,960			
1945	5,757.38	4,843	5,757			
1946	9,232.87	7,719	9,233			
1947	22,386.19	18,589	22,386			
1948	24,597.79	20,298	24,598			
1949	22,702.82	18,616	22,703			
1950	32,460.76	26,462	32,461			
1951	35,107.26	28,451	35,107			
1952	35,880.36	28,905	35,880			
1953	65,958.49	52,846	65,958			
1954	68,233.61	54,369	68,234			
1955	80,076.83	63,485	80,077			
1956	85,868.27	67,733	85,868			
1957	85,118.91	66,801	85,119			
1958	85,558.68	66,770	85,290	269	5.49	49
1959	109,666.64	85,145	108,762	905	5.59	162
1960	108,590.10	83,875	107,139	1,451	5.69	255
1961	147,311.94	113,136	144,517	2,795	5.80	482
1962	178,095.38	135,994	173,715	4,380	5.91	741
1963	191,846.78	145,650	186,049	5,798	6.02	963
1964	221,372.50	167,003	213,325	8,048	6.14	1,311
1965	218,580.00	163,848	209,295	9,285	6.26	1,483
1966	233,914.55	174,126	222,423	11,492	6.39	1,798
1967	261,329.40	193,175	246,756	14,573	6.52	2,235
1968	299,817.49	220,066	281,106	18,711	6.65	2,814

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
1969	314,927.76	229,393	293,020	21,908	6.79	3,227
1970	276,092.25	199,449	254,770	21,322	6.94	3,072
1971	241,532.57	173,034	221,028	20,505	7.09	2,892
1972	335,064.09	237,896	303,881	31,183	7.25	4,301
1973	232,583.82	163,646	209,037	23,547	7.41	3,178
1974	181,732.22	126,631	161,755	19,977	7.58	2,635
1975	140,915.58	97,232	124,201	16,715	7.75	2,157
1976	140,171.94	95,709	122,256	17,916	7.93	2,259
1977	298,944.12	201,967	257,987	40,957	8.11	5,050
1978	395,530.23	264,214	337,499	58,031	8.30	6,992
1979	587,372.62	387,901	495,493	91,880	8.49	10,822
1980	633,042.92	412,997	527,550	105,493	8.69	12,140
1981	601,151.28	387,382	494,830	106,321	8.89	11,960
1982	715,504.94	455,061	581,281	134,224	9.10	14,750
1983	732,780.68	459,893	587,454	145,327	9.31	15,610
1984	963,910.42	596,468	761,910	202,000	9.53	21,196
1985	1,564,220.80	954,175	1,218,835	345,386	9.75	35,424
1986	2,019,625.12	1,213,391	1,549,949	469,676	9.98	47,062
1987	2,061,548.49	1,218,787	1,556,842	504,706	10.22	49,384
1988	2,029,718.42	1,180,484	1,507,915	521,803	10.46	49,886
1989	2,015,801.37	1,153,038	1,472,856	542,945	10.70	50,743
1990	2,094,198.36	1,176,939	1,503,387	590,811	10.95	53,955
1991	2,465,829.43	1,360,152	1,737,418	728,411	11.21	64,979
1992	2,889,414.81	1,563,751	1,997,489	891,926	11.47	77,762
1993	3,211,874.40	1,703,578	2,176,100	1,035,774	11.74	88,226
1994	3,566,609.76	1,853,210	2,367,235	1,199,375	12.01	99,865
1995	4,112,987.19	2,091,043	2,671,036	1,441,951	12.29	117,327
1996	2,376,406.40	1,180,599	1,508,062	868,344	12.58	69,026
1997	340,051.00	164,993	210,757	129,294	12.87	10,046
1998	464,855.63	219,970	280,983	183,873	13.17	13,962
1999	3,016,987.94	1,390,228	1,775,836	1,241,152	13.48	92,074
2000	2,400,703.70	1,076,476	1,375,058	1,025,646	13.79	74,376
2001	1,798,387.48	783,378	1,000,664	797,723	14.11	56,536
2002	5,471,140.36	2,311,010	2,952,015	2,519,125	14.44	174,455
2003	6,413,711.93	2,624,491	3,352,446	3,061,266	14.77	207,262
2004	4,914,496.07	1,944,175	2,483,431	2,431,065	15.11	160,891
2005	4,343,929.30	1,657,643	2,117,424	2,226,505	15.46	144,017
2006	4,496,388.31	1,651,074	2,109,032	2,387,356	15.82	150,907
2007	3,968,518.69	1,398,506	1,786,410	2,182,109	16.19	134,781
2008	4,805,350.02	1,622,286	2,072,260	2,733,090	16.56	165,042
2009	4,703,426.28	1,514,503	1,934,581	2,768,845	16.95	163,354

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. 0						
2010	6,687,017.09	2,046,227	2,613,789	4,073,228	17.35	234,768
2011	3,658,123.49	1,057,929	1,351,367	2,306,756	17.77	129,812
2012	625,564.31	169,903	217,029	408,535	18.21	22,435
2016	123,725.00	23,260	29,712	94,013	20.30	4,631
2017	298,702.14	48,868	62,422	236,280	20.91	11,300
2018	135,546.61	18,651	23,824	111,723	21.56	5,182
2020	5,908,931.19	482,169	615,908	5,293,023	22.96	230,532
2021	5,960,584.57	302,798	386,785	5,573,800	23.73	234,884
2022	2,267,261.98	40,811	52,131	2,215,131	24.55	90,229
	112,683,413.98	45,739,505	58,407,752	54,275,662		3,449,649
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.7	3.06

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R1.5						
NET SALVAGE PERCENT.. 0						
1927	2,615.56	2,616	2,616			
1941	2,615.56	2,616	2,616			
1942	2,615.56	2,616	2,616			
1947	2,615.56	2,616	2,616			
1948	2,615.56	2,616	2,616			
1949	2,615.56	2,616	2,616			
1950	2,615.56	2,616	2,616			
1951	2,615.56	2,616	2,616			
1952	2,615.56	2,616	2,616			
1953	5,231.12	5,188	4,183	1,048	0.29	1,048
1954	3,238.31	3,182	2,566	672	0.61	672
1955	3,238.31	3,151	2,541	697	0.94	697
1956	3,238.31	3,120	2,516	722	1.28	564
1957	5,713.64	5,449	4,394	1,320	1.62	815
1958	5,713.64	5,397	4,352	1,362	1.94	702
1959	3,238.31	3,031	2,444	794	2.24	354
1961	15,266.19	14,075	11,349	3,917	2.73	1,435
1962	46,082.07	42,185	34,014	12,068	2.96	4,077
1963	51,578.32	46,892	37,809	13,769	3.18	4,330
1964	68,982.82	62,262	50,202	18,781	3.41	5,508
1965	56,135.51	50,281	40,542	15,594	3.65	4,272
1966	57,646.14	51,223	41,301	16,345	3.90	4,191
1967	69,836.45	61,556	49,633	20,203	4.15	4,868
1968	60,926.17	53,232	42,921	18,005	4.42	4,074
1969	97,255.48	84,223	67,910	29,345	4.69	6,257
1970	144,480.88	123,965	99,954	44,527	4.97	8,959
1971	106,293.80	90,350	72,850	33,444	5.25	6,370
1972	44,951.01	37,836	30,507	14,444	5.54	2,607
1973	39,621.65	33,010	26,616	13,006	5.84	2,227
1974	8,117.50	6,693	5,397	2,720	6.14	443
1975	21,616.64	17,633	14,218	7,399	6.45	1,147
1976	18,925.82	15,265	12,308	6,618	6.77	978
1979	7,086.98	5,512	4,444	2,643	7.78	340
1980	357,462.34	274,327	221,192	136,270	8.14	16,741
1981	484,855.55	366,968	295,889	188,967	8.51	22,205
1982	424,586.61	316,742	255,391	169,196	8.89	19,032
1983	436,296.81	320,491	258,414	177,883	9.29	19,148
1984	407,054.32	294,243	237,250	169,804	9.70	17,506
1985	609,088.06	432,976	349,111	259,977	10.12	25,689
1986	624,874.78	436,344	351,827	273,048	10.56	25,857
1987	1,084,269.25	742,876	598,986	485,283	11.02	44,037

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R1.5						
NET SALVAGE PERCENT.. 0						
1988	1,036,930.55	696,517	561,606	475,325	11.49	41,369
1989	1,042,768.19	686,141	553,240	489,528	11.97	40,896
1990	983,684.49	633,208	510,560	473,124	12.47	37,941
1991	1,441,930.22	906,772	731,136	710,794	12.99	54,719
1992	1,480,849.88	908,812	732,781	748,069	13.52	55,331
1993	424,396.99	253,912	204,731	219,666	14.06	15,623
1994	2,593,915.39	1,510,411	1,217,854	1,376,061	14.62	94,122
1995	2,892,376.13	1,637,085	1,319,992	1,572,384	15.19	103,514
1996	1,917,821.50	1,053,152	849,163	1,068,658	15.78	67,722
1997	1,826,487.19	972,221	783,908	1,042,579	16.37	63,688
1998	2,381,240.54	1,225,315	987,979	1,393,262	16.99	82,005
1999	2,872,814.68	1,427,387	1,150,911	1,721,904	17.61	97,780
2000	1,642,032.11	785,827	633,617	1,008,415	18.25	55,256
2001	522,588.41	240,391	193,829	328,759	18.90	17,395
2002	814,404.24	359,266	289,678	524,726	19.56	26,826
2003	971,243.08	409,865	330,477	640,766	20.23	31,674
2004	1,333,537.50	536,842	432,859	900,678	20.91	43,074
2005	1,090,934.13	417,359	336,519	754,415	21.61	34,910
2006	1,174,217.79	425,736	343,274	830,944	22.31	37,245
2007	1,000,936.73	342,611	276,249	724,688	23.02	31,481
2008	674,249.98	216,913	174,898	499,352	23.74	21,034
2009	505,636.84	152,126	122,660	382,977	24.47	15,651
2010	220,977.00	61,809	49,837	171,140	25.21	6,789
2011	302,607.81	78,245	63,089	239,519	25.95	9,230
2012	4,897,157.98	1,161,312	936,373	3,960,785	26.70	148,344
2013	4,050,121.01	872,518	703,517	3,346,604	27.46	121,872
2014	6,633,286.64	1,284,934	1,036,051	5,597,236	28.22	198,343
2015	6,642,982.70	1,138,807	918,228	5,724,755	29.00	197,405
2016	10,189,824.91	1,519,710	1,225,352	8,964,473	29.78	301,023
2017	10,087,453.49	1,279,694	1,031,826	9,055,627	30.56	296,323
2018	10,330,005.29	1,077,316	868,647	9,461,358	31.35	301,798
2019	16,054,824.23	1,307,344	1,054,120	15,000,704	32.15	466,585
2020	15,309,617.88	892,398	719,546	14,590,072	32.96	442,660
2021	12,134,944.71	426,422	343,827	11,791,118	33.77	349,160
2022	12,739,212.32	149,176	120,281	12,618,931	34.59	364,814
	145,614,455.36	31,080,776	25,065,190	120,549,265		4,530,752

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.6 3.11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S4						
NET SALVAGE PERCENT.. 0						
1929	18.06	18	18			
1930	36.12	36	36			
1931	76.82	77	77			
1933	243.97	244	244			
1934	112.95	113	113			
1935	36.12	36	36			
1936	76.82	77	77			
1937	131.01	131	131			
1938	149.07	149	149			
1939	94.89	95	95			
1940	262.03	262	262			
1941	94.89	95	95			
1942	131.01	131	131			
1943	167.13	167	167			
1944	280.09	280	280			
1945	338.85	339	339			
1946	262.03	262	262			
1947	1,671.63	1,672	1,672			
1948	524.06	524	524			
1949	1,350.84	1,351	1,351			
1950	2,403.53	2,404	2,404			
1951	2,796.57	2,797	2,797			
1952	3,320.62	3,321	3,321			
1953	1,874.89	1,875	1,875			
1954	10,057.99	10,058	10,058			
1955	5,155.77	5,156	5,156			
1956	3,549.88	3,550	3,550			
1957	6,423.59	6,424	6,424			
1958	5,493.85	5,494	5,494			
1959	5,409.34	5,409	5,409			
1960	4,226.05	4,226	4,226			
1961	3,812.75	3,813	3,813			
1962	7,921.72	7,874	5,651	2,271	0.21	2,271
1963	5,333.85	5,255	3,771	1,563	0.52	1,563
1964	4,879.52	4,790	3,438	1,442	0.64	1,442
1965	6,400.62	6,267	4,498	1,903	0.73	1,903
1966	7,368.66	7,194	5,163	2,206	0.83	2,206
1967	13,156.83	12,811	9,194	3,963	0.92	3,963
1968	14,480.46	14,054	10,087	4,393	1.03	4,265
1969	18,391.96	17,793	12,770	5,622	1.14	4,932
1970	40,438.56	38,983	27,978	12,461	1.26	9,890

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 387.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S4						
NET SALVAGE PERCENT.. 0						
1971	3,913.88	3,761	2,699	1,215	1.37	887
1972	27,920.15	26,732	19,185	8,735	1.49	5,862
1973	36,510.46	34,820	24,990	11,520	1.62	7,111
1974	19,042.58	18,085	12,980	6,063	1.76	3,445
1975	8,590.31	8,122	5,829	2,761	1.91	1,446
1976	13,743.91	12,935	9,283	4,461	2.06	2,166
1977	16,917.40	15,840	11,368	5,549	2.23	2,488
1978	23,302.45	21,705	15,578	7,724	2.40	3,218
1979	27,158.83	25,149	18,049	9,110	2.59	3,517
1980	21,519.71	19,804	14,213	7,307	2.79	2,619
1981	21,974.74	20,091	14,419	7,556	3.00	2,519
1982	19,301.47	17,520	12,574	6,727	3.23	2,083
1983	31,061.86	27,973	20,076	10,986	3.48	3,157
1984	346,651.35	309,411	222,064	124,587	3.76	33,135
1985	39,511.45	34,940	25,076	14,435	4.05	3,564
1986	37,109.14	32,476	23,308	13,801	4.37	3,158
1987	66,641.15	57,673	41,392	25,249	4.71	5,361
1988	52,454.95	44,826	32,172	20,283	5.09	3,985
1989	15,094.73	12,723	9,131	5,964	5.50	1,084
1990	190,883.64	158,489	113,747	77,137	5.94	12,986
1991	35,328.02	28,848	20,704	14,624	6.42	2,278
1992	22,981.93	18,418	13,219	9,763	6.95	1,405
1993	28,299.85	22,219	15,947	12,353	7.52	1,643
1994	86,609.81	66,491	47,720	38,890	8.13	4,784
1995	35,328.02	26,445	18,980	16,348	8.80	1,858
1996	22,981.93	16,744	12,017	10,965	9.50	1,154
1997	68,945.80	48,735	34,977	33,969	10.26	3,311
1998	22,981.93	15,720	11,282	11,700	11.06	1,058
2021	7,991,283.53	342,506	245,816	7,745,468	33.50	231,208
2022	19,976,886.45	285,470	204,882	19,772,005	34.50	573,102
	29,489,886.83	1,950,278	1,416,813	28,073,074		958,027
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.3						3.25

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. 0						
2003	8,589,887.39	2,606,601	2,576,637	6,013,250	38.31	156,963
2004	151,590.00	43,796	43,293	108,297	39.11	2,769
2007	304,873.48	74,557	73,700	231,173	41.55	5,564
2010	5,302.35	1,056	1,044	4,258	44.05	97
2011	2,433,934.29	447,406	442,263	1,991,671	44.89	44,368
2012	333,910.38	56,157	55,511	278,399	45.75	6,085
2013	809,106.07	123,575	122,154	686,952	46.60	14,741
2015	211,327.04	25,628	25,333	185,994	48.33	3,848
2016	777,617.61	82,000	81,057	696,561	49.20	14,158
2017	2,166,774.12	193,818	191,590	1,975,184	50.08	39,441
2018	7,347,918.65	538,382	532,194	6,815,725	50.97	133,720
2019	76,269.31	4,368	4,317	71,952	51.85	1,388
2021	34,640.51	850	841	33,800	53.65	630
2022	19,780.52	162	160	19,621	54.55	360
	23,262,931.72	4,198,356	4,150,094	19,112,838		424,132
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					45.1	1.82

Schedule JJS-2

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in

the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the

Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:

"Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
356.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
357.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
358.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
359.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
360.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
361.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
362.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
363.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
364.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
365.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
366.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
367.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
368.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
369.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
371.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
372.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
373.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
374.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation
375.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
377.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
378.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
379.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
380.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
381.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
382.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
383.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
384.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
385.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
386.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
387.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
388.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
389.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
390.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
391.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
392.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
393.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
395.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
396.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
397.	2022	PA PUC	R-2022-3031672; R-2022-	Pennsylvania-American Water Company	Depreciation
398.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
399.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
400.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power Company	Depreciation
401.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
402.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
403.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation
404.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
405.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
406.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
407.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
408.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
409.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
410.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
412.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
413.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
414.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
415.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
416.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
417.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
418.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
419.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
420.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
421.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
422.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
423.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison Company	Depreciation
424.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
425.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
426.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
427.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
428.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
429.	2023	PSC MD	Case No. 9695	The Potomac Edison Company	Depreciation
430.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
431.	2023	FERC	Docket No. ER23-xxx-000	PPL Electric Utilities	Depreciation
432.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
433.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
434.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
435.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
436.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
437.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
438.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
439.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation
440.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation
441.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
442.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
443.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
444.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
445.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

COMPARISON OF EXISTING AND PROPOSED RATES AND ACCRUALS RELATED TO
ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2022	EXISTING RATE	EXISTING ACCRUALS	PROPOSED RATE	PROPOSED ACCRUALS	DIFFERENCE IN ACCRUALS
	(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(4)-(6)
	ELECTRIC PLANT						
	DISTRIBUTION PLANT						
360.30	SIDEWALKS AND CURBS ON PUBLIC PROPERTY	1,218,246.29	2.04	24,852	0.97	11,797	(13,055)
361.00	STRUCTURES AND IMPROVEMENTS	241,611,849.94	1.53	3,696,661	1.49	3,590,567	(106,094)
362.00	STATION EQUIPMENT	1,563,499,955.95	2.06	32,208,099	2.83	44,203,495	11,995,396
364.00	POLES, TOWERS AND FIXTURES	1,024,137,859.55	3.71	37,995,515	3.56	36,416,835	(1,578,680)
365.00	OVERHEAD CONDUCTORS AND DEVICES	2,855,533,126.70	1.80	51,399,596	1.92	54,799,572	3,399,976
366.00	UNDERGROUND CONDUIT	509,797,650.33	1.14	5,811,693	1.03	5,252,805	(558,888)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1,461,353,642.60	1.66	24,258,470	2.00	29,166,169	4,907,699
368.00	LINE TRANSFORMERS	1,582,143,710.59	3.38	53,476,457	3.12	49,384,525	(4,091,932)
369.00	SERVICES	535,118,075.54	1.84	9,846,173	3.53	18,874,501	9,028,328
370.00	METERS	365,421,420.67	9.89	36,140,179	7.68	28,064,055	(8,076,124)
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	498,983,988.92	3.71	18,512,306	3.64	18,144,341	(367,965)
	TOTAL DISTRIBUTION PLANT	**10,638,819,527.08**	**2.57**	**273,370,001**	**2.71**	**287,908,662**	**14,538,661**
	GENERAL PLANT - STRUCTURES AND IMPROVEMENTS						
390.00	STRUCTURES AND IMPROVEMENTS - DISTRIBUTION	34,060,708.63	0.99	337,201	1.80	612,821	275,620
	TOTAL STRUCTURES AND IMPROVEMENTS	**34,060,708.63**	**0.99**	**337,201**	**1.80**	**612,821**	**275,620**
	GENERAL PLANT - AMORTIZED						
391.10	OFFICE FURNITURE	14,686,628.83	5.00	734,331	5.00	734,331	0
391.20	OFFICE EQUIPMENT	272,720.08	25.00	68,180	25.00	68,180	0
391.31	OFFICE COMPUTER EQUIPMENT	13,045,730.89	14.29	1,864,235	14.29	1,864,235	0
392.10	TRANSPORTATION EQUIPMENT 13,000 LBS AND UNDER	13,641,107.47	11.09	1,512,799	11.11	1,515,527	2,728
392.20	TRANSPORTATION EQUIPMENT OVER 13,000 LBS	161,495,690.14	7.67	12,386,719	7.69	12,419,019	32,300
393.00	STORES EQUIPMENT	613,067.36	14.29	87,607	14.29	87,607	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	18,295,904.22	14.29	2,614,485	14.29	2,614,485	0
395.00	LABORATORY EQUIPMENT	2,933,338.47	20.00	586,668	20.00	586,668	0
396.00	POWER OPERATED EQUIPMENT	30,192,786.24	7.69	2,321,825	7.69	2,321,825	0
397.00	COMMUNICATION EQUIPMENT	66,943,612.98	10.00	6,694,361	10.00	6,694,361	0
398.00	MISCELLANEOUS EQUIPMENT	1,738,564.62	14.29	248,441	14.29	248,441	0
	TOTAL GENERAL PLANT - AMORTIZED	**323,859,151.30**	**8.99**	**29,119,651**	**9.00**	**29,154,679**	**35,028**
	TOTAL DEPRECIABLE ELECTRIC PLANT	**10,996,739,387.01**	**2.75**	**302,826,853**	**2.89**	**317,676,162**	**14,849,309**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC PLANT

COMPARISON OF EXISTING AND PROPOSED RATES AND ACCRUALS RELATED TO ELECTRIC AND COMMON PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2022	EXISTING RATE	EXISTING ACCRUALS	PROPOSED RATE	PROPOSED ACCRUALS	DIFFERENCE IN ACCRUALS
	(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(4)-(6)
	COMMON PLANT						
	GENERAL PLANT						
390.00	STRUCTURES AND IMPROVEMENTS						
	PARK PLAZA	42,042,347.28	2.98	1,252,862	3.58	1,506,683	253,821
	LEASEHOLD IMPROVEMENTS	29,397,940.70	0.81	238,123	1.08	317,645	79,522
	TOTAL COMMON PLANT	**71,440,287.98**	**2.09**	**1,490,985**	**2.55**	**1,824,328**	**333,343**
	TOTAL DEPRECIABLE PLANT	**11,068,179,674.99**	**2.75**	**304,317,838**	**2.89**	**319,500,490**	**15,182,652**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

COMPARISON OF EXISTING AND PROPOSED RATES AND ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2022	EXISTING RATE	EXISTING ACCRUALS	PROPOSED RATE	PROPOSED ACCRUALS	DIFFERENCE IN ACCRUALS
	(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(4)-(6)
	GAS PLANT						
	PRODUCTION PLANT						
304.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	41,238.98	-	0	-	0	0
305.00	STRUCTURES AND IMPROVEMENTS	8,358,112.00	0.02	1,672	-	0	(1,672)
307.00	OTHER POWER EQUIPMENT	2,877,909.07	-	0	0.05	1448	1,448
311.00	LIQUEFIED PETROLEUM GAS EQUIPMENT	39,380,160.50	-	0	-	0	0
320.00	OTHER EQUIPMENT	227,575.42	-	0	-	0	0
	TOTAL PRODUCTION PLANT	**50,884,995.97**	**-**	**1,672**	-	**1,448**	**(224)**
	OTHER STORAGE PLANT						
361.00	STRUCTURES AND IMPROVEMENTS	293,633.92	0.10	294	2.91	8,537	8,243
362.00	GAS HOLDERS	5,066,482.48	0.12	6,080	0.30	15,084	9,004
363.20	VAPORIZING EQUIPMENT	8,763,433.13	1.75	153,360	1.78	156,116	2,756
363.40	MEASURING AND REGULATING STATION EQUIPMENT	5,428,187.16	3.23	175,330	0.86	46,712	(128,618)
	TOTAL OTHER STORAGE PLANT	**19,551,736.69**	**1.71**	**335,064**	**1.16**	**226,449**	**(108,615)**
	TRANSMISSION PLANT						
367.00	MAINS	93,786,846.70	1.00	937,868	1.20	1,122,929	185,061
369.00	MEASURING AND REGULATING STATION EQUIPMENT	4,336,420.46	10.94	474,404	15.36	665,932	191,528
	TOTAL TRANSMISSION PLANT	**98,123,267.16**	**1.44**	**1,412,272**	**1.82**	**1,788,861**	**376,589**
	DISTRIBUTION PLANT						
374.30	SIDEWALKS AND CURBS - ON PUBLIC PROPERTY	54,865.26	1.80	988	1.49	818	(170)
375.00	STRUCTURES AND IMPROVEMENTS	103,089,212.29	0.61	628,844	1.40	1,441,463	812,619
376.00	MAINS	3,768,890,222.03	1.39	52,387,574	1.73	65,241,302	12,853,728
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	155,052,903.89	2.25	3,488,690	2.01	3,121,832	(366,858)
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	102,610,302.42	1.01	1,036,364	1.58	1,617,169	580,805
380.00	SERVICES	5,364,802,876.79	1.81	97,102,932	2.62	140,679,855	43,576,923
381.00	METERS	477,048,046.87	4.82	22,993,716	6.23	29,698,274	6,704,558
382.00	METER INSTALLATIONS	52,631,536.57	4.92	2,589,472	10.05	5,289,817	2,700,345
383.00	HOUSE REGULATORS	38,499,123.37	3.01	1,158,824	2.93	1,128,034	(30,790)
384.00	HOUSE REGULATOR INSTALLATIONS	112,683,413.98	3.27	3,684,748	3.43	3,864,320	179,572
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	145,614,455.36	3.13	4,557,732	3.11	4,530,752	(26,980)
387.00	OTHER EQUIPMENT	29,489,886.83	6.19	1,825,424	3.25	958,027	(867,397)
	TOTAL DISTRIBUTION PLANT	**10,350,466,845.66**	**1.85**	**191,455,308**	**2.49**	**257,571,663**	**66,116,355**
	GENERAL PLANT						
390.00	STRUCTURES AND IMPROVEMENTS	23,262,931.72	1.87	435,017	1.82	424,132	(10,885)
	TOTAL STRUCTURES AND IMPROVEMENTS	23,262,931.72	1.87	435,017	1.82	424,132	(10,885)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS PLANT

COMPARISON OF EXISTING AND PROPOSED RATES AND ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2022	EXISTING RATE	EXISTING ACCRUALS	PROPOSED RATE	PROPOSED ACCRUALS	DIFFERENCE IN ACCRUALS
	(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)=(4)-(6)
	GENERAL PLANT - AMORTIZED						
391.10	OFFICE FURNITURE	12,819,389.03	5.00	640,969	5.00	640,969	0
391.20	OFFICE EQUIPMENT	0.00	25.00	0	25.00	0	0
391.30	OFFICE COMPUTER EQUIPMENT	1,569,512.98	14.29	224,283	14.29	224,283	0
391.33	PERSONAL COMPUTING EQUIPMENT	2,516,592.30	33.33	838,780	33.33	838,780	0
392.10	CARS AND LIGHT TRUCKS	26,749,925.73	10.73	2,870,267	11.11	2,971,917	101,650
392.20	HEAVY TRUCKS AND TRUCK MOUNTED EQUIPMENT	59,281,268.33	7.22	4,280,108	7.69	4,558,730	278,622
393.00	STORES EQUIPMENT	2,362,541.81	14.29	337,607	14.29	337,607	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	40,310,338.31	14.29	5,760,347	14.29	5,760,347	0
395.00	LABORATORY EQUIPMENT	824,357.78	20.00	164,872	20.00	164,872	0
396.00	POWER OPERATED EQUIPMENT	22,244,566.40	7.69	1,710,607	7.69	1,710,607	0
397.00	COMMUNICATION EQUIPMENT	6,278,285.39	10.00	627,829	10.00	627,829	0
398.00	MISCELLANEOUS EQUIPMENT	1,411,781.32	14.29	201,744	14.29	201,744	0
	TOTAL GENERAL PLANT - AMORTIZED	**176,368,559.37**	**10.01**	**17,657,413**	**10.23**	**18,037,685**	**380,272**
	TOTAL GENERAL PLANT	**199,631,491.09**	**8.52**	**17,016,444**	**9.25**	**18,461,817**	**369,387**
	TOTAL DEPRECIABLE PLANT	**10,718,658,336.57**	**1.97**	**211,296,746**	**2.59**	**278,050,238**	**66,753,492**

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 17 Electric and B.P.U.N.J. No. 17
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
MICHAEL J. ADAMS

Submitted on Behalf
of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

December 29, 2023
P-8

TABLE OF CONTENTS

I. INTRODUCTION AND WITNESS QUALIFICATIONS ..... - 1 -

II. PURPOSE AND SCOPE ..... - 3 -

III. CASH WORKING CAPITAL ..... - 3 -

IV. LEAD-LAG STUDY ..... - 4 -

A.Revenue Lag ..... - 6 -

B.Expense Leads ..... - 9 -

V. NET ASSETS and LIABILITIES ..... - 18 -

VI. CONCLUSION ..... - 19 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
MICHAEL J. ADAMS
SENIOR VICE PRESIDENT, CONCENTRIC ENERGY ADVISORS, INC.

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael J. Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom are you employed and in what position?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe Concentric.

A. Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

Q. What are your responsibilities in your current position?

A. As a Senior Vice President my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. Please describe your education.

A. I have an MBA from the University of Illinois – Springfield and a Bachelor of Science in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. Please describe your qualifications.

A. I have over thirty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements. A statement of my background and qualifications is attached as Schedule MJA-LL-1.

Q. Have you ever testified in a regulatory proceeding?

A. Yes. I have provided expert testimony or reports before the Arizona Corporation Commission; Arkansas Public Service Commission; the Connecticut Public Utilities Regulatory Authority, the Federal Energy Regulatory Commission (FERC); the Georgia Public Service Commission; the Hawaii Public Utilities Commission; the Idaho Public Utilities Commission; the Illinois Commerce Commission; the Kentucky Public Service Commission; the Maine Public Utilities Commission; the Maryland Public Service Commission; the Massachusetts Department of Public Utilities; the Missouri Public Service Commission; the Montana Public Service Commission, the New Hampshire Public Utilities Commission; the New Mexico Public Regulation Commission; the State of New Jersey Board of Public Utilities; the Oklahoma Corporation Commission; the Ontario Energy Board; the Pennsylvania Public Utility Commission; Public Utilities Commission of the State of South Dakota; the Tennessee Public Utility

Commission; the Texas Public Utility Commission; the Virginia State Corporation Commission; and the West Virginia Public Service Commission.

My testimonies typically address issues related to affiliate transactions, cash working capital, cost of service/revenue requirement, shared services, accounting, cost allocations and/or regulatory policies and practices.

II. PURPOSE AND SCOPE

Q. What is the purpose of your direct testimony?

A. I have been asked by Public Service Electric and Gas Company ("PSE&G" or the "Company") to prepare and discuss a lead-lag study that was used to develop Cash Working Capital ("CWC") factors that were ultimately used to calculate the cash working capital requirements for the Company's electric and gas operations. I also discuss the analysis of the Company's net assets and liabilities, which are a separate source of working capital. The Company has included the results of the lead lag study and the net asset and liabilities analyses in its rate base. Discussion of the studies follow.

III. CASH WORKING CAPITAL

Q. Please define what you mean by the phrase "cash working capital requirement."

A. The cash working capital requirement is the amount of funds the Company is required tomaintain on hand to finance the day-to-day operations of the Company.

Q. Are you sponsoring any scheduless in this proceeding related to your analysis of pseg's cash working capital requirement?

A. Yes. Schedules MJA-LL-2 through MJA-LL-3 set forth the results of the lead lag study and Net Assets and Liabilities analyses, respectively. Schedules MJA-LL-6 to -MJA-LL-18 are the workpapers supporting the lead-lag study and Net Assets and Liabilities analyses, respectively. The schedules were prepared under my direction and supervision and are accurate and complete to the best of my knowledge and belief.

IV. LEAD-LAG STUDY

Q. For what period was the lead-lag study performed?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2022. The leads and lags were applied to expense amounts for the Test Year.

Q. How should the results of the cash working capital analysis and the net assets and liabilities be treated for ratemaking purposes?

A. The cash working capital requirements calculated using the CWC factors from the lead-lag study and the results of the net assets and liabilities analyses should be included as part of PSE&G's electric and gas operations rate base for ratemaking purposes.

Q. Is the analysis of the revenue lags and expense leads typically referred to as a lead-lag study?

A. Yes. Cash working capital requirements are typically determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date the customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date. The "leads" and "lags"

are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. The CWC factor is multiplied by the appropriate annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied in this proceeding are described in the testimony of Company witness Mr. McFadden.

Q. What are the various leads and lags that were considered in the cash working capital analysis?

A. Two broad categories of leads and lags were considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company, as well as the various taxes and other expenses paid by the Company ("expense leads").

Q. What is a revenue lag?

A. A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., electricity and/or gas) and its ability to use the funds received as payment for the delivery of the product.

Q. What is an expense lead?

A. An expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Q. What was the source of information you employed to determine the leads and lags in your cash working capital analysis?

A. Information from the Company was utilized, including data from Accounts Receivables, Accounts Payable, Customer Service, Human Resources, Payroll, and Tax systems. The information derived from these sources, together with the analysis of specific transactions, led to the determination of the appropriate number of lead-lag days for PSE&G's New Jersey electric and gas operations.

A. Revenue Lag

Q. How was the revenue lag determined?

A. The revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company. In the calculation, the revenue lag was divided into four distinct components: 1) service lag; 2) billing lag; 3) collection lag; and 4) bank float. An explanation of each component of the revenue lag follows.

Q. What is meant by service lag?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for the service period. Using the mid-point methodology, the service lag was determined to be 15.21 days (365 days in the year divided by 12 months divided by 2).

Q. What is meant by billing lag?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's

monthly billing schedules and meter reading records. The average billing lag was determined to be 1.72 days. Refer to Schedule MJA-LL-6 for the calculation of the billing lag.

Q. What is meant by collection lag?

A. The collection lag refers to the average amount of time from the date when the customer received a bill to the date that the Company received payment from its customer. For purposes of the cash working capital analyses, the Company's actual customer receivables during the twelve months ended September 30, 2023 were analyzed to determine the collection lag. Based on weighted average data from the Company and by considering accounts receivables balances by days aged, the average collection lag was determined to be 50.65 days. Due to potential impacts from the pandemic during the test period of the study, the twelve months ended September 30, 2023 was used to reflect current customer payment patterns post-pandemic.

Q. Explain the calculation of the Company's collection lag.

A. The Company's monthly accounts receivable data was categorized into aging "buckets" of 0-30 days, 31-60 days, 61-90 days, 91-120 days and 120+ days outstanding. For purposes of calculating the collection lag, it was assumed that the customers will pay their bills ratably over the month. Therefore, the midpoint of the first month was determined to be 15 days (*i.e.*, 30 divided by 2). The same assumption that customers will pay their bills ratably over the course of the month was applied to each aging bucket. It was further assumed that customers will pay their bills ratably over the course of the second month (the month that is 31-60 days after the bill was issued). Therefore, the midpoint of payments received 31-60 days after the bill was issued is 45 days (*i.e.*, 30 days outstanding from the first month plus the 15-day midpoint of the second month = 45 days). This same theory applies to the use of 75 days for payments that were received 61-90

days after the bill is issued as well as the use of 105 days for the 91-120 days period. Receivables outstanding for 120 days or longer were conservatively capped at 120 days. The accounts receivable dollars in each bucket were then multiplied by the midpoint of each bucket to calculate the collections lag. Refer to Schedule MJA-LL-7 for the calculation of the collections lag.

Q. What does bank float represent?

A. Bank float represents the elapsed time from when customers' payments were deposited at the bank to when such funds were available to the Company. Based upon an analysis of the availability of deposited funds in the months of February, March and April 2022, the bank float was determined to be 0.92 days. Refer to Schedule MJA-LL-7 for the calculation of the bank float lag.

Q. Please summarize the calculation of revenue lag days.

A. The overall revenue lag, by lag component, is summarized in the following table.

Revenue Lag by Component	
Service Lag	15.21
Billing Lag	1.72
Collections Lag	50.65
Bank Float	0.92
Total Lag	**68.50**

Q. Has the Company included Energy Sales Taxes in its revenues when determining its total revenue requirement?

A. Yes. New Jersey energy sales taxes are included as a separate line item added to the revenue requirement in the determination of the total revenue requirement. The New Jersey energy sales tax is included as part of the revenue requirement lag. Customers are billed the Energy Sales Tax, known as the Sales and Use Tax (SUT), by the Company and the Company remits the charges to the State. The Company is required to remit these dollars to the State in advance of their

collection and the timing difference between the remittance to the State and the collection from customers represents a working capital requirement.

B. Expense Leads

Q. What expense-related leads were considered in the lead-lag analysis?

A. Lead times associated with the following expense categories were considered in the lead-lag study: a) Salaries and Wages; b) Incentive Compensation; c) Pensions and Employee Benefits; d) Other O&M; e) Purchased Power and Gas Supply Costs; f) Taxes Other than Income Taxes; g) Federal and State Income Taxes; h) Interest on Long-Term Debt; i) Service Company Expenses; j) New Jersey Energy Sales Tax; and k) depreciation and amortization expense and operating income.

Q. Provide an explanation of the expense lead associated with the Company's salaries and wages including incentive compensation.

A. Considering PSE&G's various payroll periods (i.e., weekly and bi-weekly) and incentive compensation paid to employees, the salaries and wages expense lead was determined to be 25.38 days. Refer to Schedule MJA-LL-8 for the calculation of the salaries and wages expense lead.

Q. What employee benefits does the company provide to its empoyees and what are the expense leads associated with such benefits?

A. The Company provides benefits for its employee associated with medical, dental, group life insurance, disability (short-term disability and long-term disability), workers' compensation, other post-employment benefits ("OPEB"), pension and 401(k) matching. Using the amounts paid/contributed by the Company, the timing of the payments, and the period each payment was applied for each benefit category, the dollar-weighted expense lead for each of the benefits was determined to be as follows: medical 12.86 days; dental 2.94 days; group life insurance 15.03 days;

short-term and long-term disability 45.89 days; OPEB 0 days; pension 15.17 days; 401(k) matching 12.57 days and workers' compensation 1.63 days. Refer to Schedule MJA-LL-9 for the calculations of the individual employee benefits expense leads.

Q. What are "other O&M expenses" and how was the expense lead calculated for such expenses?

A. The Company engages in transactions with vendors for a variety of purposes including facility maintenance, system maintenance, customer service, as well as other services. Accounts payable data was analyzed in order to calculate a lead time associated with the payment for services related to other O&M activities. The analysis indicated that on average, invoices were paid by the Company 36.10 days after receipt. Where appropriate, this lead time includes a service lead time. Refer to Schedule MJA-LL-10 for the calculation of the Other O&M expense lead.

Q. What expense lead was applied to purchased power in the study?

A. The Company purchases power from two separate groups: Basic Generation Service ("BGS") suppliers and Non-Utility Generators ("Purchased Electric Power"). BGS is the Company's default supply obligation for all its customers that do not choose to obtain electric power from a third-party supplier. Purchased Electric Power requires the Company to purchase power from qualifying facilities that generate less than 20MW. Based on an analysis of the service periods and payment dates for the Company's purchase of power from the two separate groups during the period examined, a weighted expense lead of 35.83 days was determined. Refer to Schedule MJA-LL-11 for the calculation of the purchased power expense lead.

Q. What is the expense lead time associated with the Company's Natural Gas Expenses?

A. The Company purchases natural gas for distribution to its gas customers. Based on an examination of the service periods and payment dates for the Company's purchases of natural gas, a weighted expense lead time of 35.63 days was determined. Refer to Schedule MJA-LL-12 for the calculation of the natural gas expense lead..

Q. What are the various general taxes considered in the Cash working capital analysis?

A. The following general taxes were considered in the study: a) Real Estate Taxes; b) Payroll Taxes; and c) Newark City Tax. Each of the taxes are described below.

Q. Explain the lead days associated with each type of general taxes in the cash working capital analysis.

A. The treatment of each category of general taxes in the study is described below:

Real Estate Tax: The Company makes payments to various taxing authorities in the State of New Jersey. Taking the periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the property tax payments, a dollar-weighted expense lead of negative 39.09 days was determined. Refer to Schedule MJA-LL-13 for the calculation of the Real Estate tax expense lead.

Payroll Tax: Based on an analysis of the pay periods and dates for the Company's payment of payroll taxes (FICA, social security/medicare, federal and state unemployment taxes), a weighted expense lead of 16.96 days was determined. Refer to Schedule MJA-LL-13 for the calculation of the Payroll tax expense lead.

Newark City Tax: Residents of Newark pay a flat city income taxon earned income in addition to the New Jersey state income tax and federal income tax. Non-residents who

work in Newark also pay a local income tax. This tax is imposed on employers. Based on the periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts taken into consideration for the Newark City Tax a dollar-weighted expense lead of 75.46 days was calculated. Refer to Schedule MJA-LL-13 for the calculation of the Newark City tax lead.

Taking the above into account, a weighted average expense lead of 6.95 days was calculated for taxes other than income taxes.

Q. How did your study address federal income taxes?

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code which requires estimated tax payments of 25 percent of total income taxes due each quarter of the current year. The first quarter payment is due by April 15th, while the second, third and fourth quarter payments are due on June 15th, September 15th, and December 15th, respectively. Taking this schedule into consideration a lead time of 37.88 days for federal income taxes was determined. Refer to Schedule MJA-LL-14 for the calculation of the federal income tax expense lead.

Q. How did you address state income taxes?

A. The expense lead for state income taxes was calculated based on the statutory tax due dates for Corporation Business Tax. Estimated payments are due on the 15th day of April, May, June, and December. This resulted in a calculated expense lead of negative 47.25 days. Refer to Schedule MJA-LL-14 for the calculation of the state income tax expense lead.

Q. Please describe how lead times associated with the Company's long-term interest expenses were addressed by the study.

A. The Company made semi-annual interest payments on its long-term debt throughout the test year. Using the midpoints of the semi-annual service periods, a dollar-weighted lead of 91.8 days for long-term interest payments was determined. Refer to Schedule MJA-LL-15 for the calculation of the interest expense lead.

Q. Provide a description of how service company expenses were addressed by the study.

A. Using the monthly invoices for charges to PSE&G from PSEG Services Corporation, a weighted-average service company expense lead of 35.91 days was determined. Refer to Schedule MJA-LL-16 for the calculation of the service company expense lead.

Q. How did your study address New Jersey energy sales tax?

A. "Charges for utility service provided and usually billed by New Jersey's public utility energy companies also are subject to the 6.625% New Jersey Sales Tax. These charges have been fully subject to the New Jersey Sales Tax since January 1, 1998".[1] The lead time for the New Jersey energy sales tax was calculated based on the midpoint of the tax liability period to the payment date, weighted by the actual amount paid. This resulted in a lead time of negative 48.71 days. Refer to Schedule MJA-LL-17 for the calculation of the New Jersey Energy Sales tax expense lead.

[1] New Jersey Treasury, Division of Taxation. NJ Division of Taxation - New Jersey Sales and Use (state.nj.us)

Q. Did you include depreciation, amortization, and deferred tax expense in the lead-lag study?

A. Yes. PSEG has historically been authorized to apply an expense lead to expenses such as depreciation, amortization, and deferred tax expense. When these expenses reduce rate base, the Company is deprived of the return that investment in rate base affords. If there is a lag between the reduction in rate base and the receipt of revenues recovering the expense, a carrying cost is incurred by the Company for the time of the lag. As such, it is appropriate for these expenses to be part of a working capital allowance.

The lead-lag study includes depreciation, amortization, and deferred tax expenses with an expense lag of 15.2 days (i.e., based on the mid-month convention, 365/12/2). There remains a lag between when assets in rate base are reduced through depreciation and when the Company receives cash from ratepayers for services provided. Therefore, it is appropriate for the Company to be compensated for the use of cash to keep the Company whole.

Q. Was the topic of including depreciation in cash working capital a topic addressed by Robert L. Hahne in "Accounting for Public Utilities"?

A. Yes, it was.

Q. Please describe how Mr. Hahne concluded that depreciation should be handled in a lead-lag study.

A. Mr. Hahne stated as follows: [2]

> Depreciation expense reflects a zero lag. This zero lag is a noncash charge and therefore cannot produce a need for cash working capital.[3]

[2] *Accounting for Public Utilities*, Hahne, Robert L., Chapter 5, Section 5.04, Cash Working Capital.

[3] Id.

This noncash treatment is based on the assumptions that there is no cash outlay associated with depreciation costs that investor funding is not required to pay these expenses. In fact, there was a related cash outlay when the properties were built. The sequence of events is as follows:

1. Investor funds are expended to construct a facility;
2. The facility is used to provide services with concurrent recording of a portion of the costs as depreciation expense;
3. Customers are billed for the depreciation costs incurred; and
4. Customers pay their bills with cash outlays by investors, ends with cash recovery by investors. In the interim, investors are funding the provision of utility services, and such funding must be recognized in rate base.

As the expenses are recorded, equal revenues are *recoverable* from ratepayers as reimbursement to investors and the accumulated provisions are deducted from rate base. The rate base reduction presumes that *recovery* of the recorded depreciation reserves has occurred. If the presumed recovery actually existed, there would be no justification for inclusion of the depreciation expense in cash working capital. The *recovery* assumption, however, is not correct. When the depreciation expense is recorded, the recovery is in the form of an increase in the accounts receivable from customers. The expense is recorded in one period. The actual recovery occurs later (after the service, billing, and collection period recognized in other lead-lag components). In the interim, the investor has not realized the recovery of capital that is imputed by the deduction of recorded depreciation expense. The funds due and payable to investors are being held by ratepayers, and the ratepayers should reimburse the investors for the time value of unpaid amounts due.

Q. Has the BPU Historically included depreciation in the determination of regulated utilities' cash working capital requirements?

A. Yes. The BPU has historically approved the inclusion of depreciation in the determination of cash working capital. The Company's inclusion of depreciation in the determination of its cash working capital requirement is consistent with the BPU's previous treatment and decisions.

Q. If depreciation expense were correctly included in the cash working capital requirement, as you have proposed, is the Company's depreciation expense being recovered via the proposed cash working capital allowance?

A. No. Depreciation expense is **not** being recovered via the cash working capital allowance, nor is there a double recovery of the expense. It is merely the timing difference that by appropriately including depreciation in the cash working capital determination allows investors the opportunity to be fully and fairly compensated for investment in utility assets from the time cash is expended until the time cash is recovered from customers. The Board has hitorically approved the inclusion of non-cash items in the lead-lag study, such as depreciation expense.

Q. Is it your recommendation that the Company should be permitted to include depreciation expense in the cash working capital analysis at zero expense lead, as the BPU has allowed in prior rate proceedings?

A. Yes, it is. Such treatment is consistent with past BPU practice.

Q. Is it your recommendation that the Company should be permitted to include amortization in the same manner as depreciation?

A. Yes, it is. Including amortization expense and assigning a zero lead to the expense recognizes that investor funding occurred but it has not yet been recovered from customers.

Q. How was operating income treated in the lead-lag study?

A. Operating income was included in the lead-lag study with an expense lead of zero days.

Q. Please explain why operating income was included in the study with a zero day lead.

A. A zero day lead was assigned to operating income, or return on invested capital, because operating income is earned when service is provided to the Company's customers, and belongs to investors when earned. As shown in the calculation of the revenue lag, operating income is not collected when earned. Therefore, a zero day lag was assigned to operating income to reflect that the Company's income has not been recovered from customers.

Q. How was pension and OPEB expense treated in the cash working capital analysis?

A. The OPEB expense in the lead-lag study is calculated using a zero-day expense lead, because the ratepayer is receiving a benefit from PSE&G's inclusion of the net OPEB liability in the Net Assets and Liabilities analyses. Since part of pensions and OPEB are included in the Net Assets and Liabilities Analyses, Concentric considered how these expenses are booked and reflected in operating expenses. The lead days for pension expense do not include the cash contributions to the trust because the cash contribution is included in the Net Assets and Liabilities Analyses. The pension expense that is booked and reflected in operating expenses has a 15.17 lead day.

Q. Based upon the results of the lead-lag study and the level of expense sponsored by the company, what level of cash working capital requirements should be included in PSE&G's rate base?

A. PSE&G's cash working capital requirement was determined to be $577,618,364 for PSEG's electric operations. The cash working capital requirement for PSEG's gas operations is $344,066,223.

V. NET ASSETS AND LIABILITIES

Q. What does a net assets and liabilities analysis measure and how is it measured?

A. Under a net assets and liabilities analysis, certain liabilities are subtracted from particular assets. The difference in the liabilities and the assets is assumed to be the working capital requirement.

Q. What are the results of PSE&G's net assets and liabilities analyses?

A. Under a net assets and liabilities analysis, the assets require working capital while the liabilities are sources of working capital. The amounts in the selected assets and liabilities accounts are shown in Schedule MJA-LL-3. The amounts in these accounts were not considered when analyzing the leads and lags for operating expenses, but they have a direct relationship with the electric and gas distribution rate base of PSEG. The amounts included in current assets are other accounts receivable, special deposits, other prepayments, miscellaneous deferred debits and other post-retirement benefits.

Other miscellaneous accounts receivable are predominantly damage claims related to electric pole repairs, and other receivables such as billings for reimbursable repair work. Such expenditures are required to be made in the day-to-day operations of the Company, but are not charged to utility operations and therefore, were not included in the lead-lag study. These expenditures are eventually reimbursed by the State or other agencies. There is, however, a continuing working capital investment required for such expenditures until reimbursement is received.

Post-retirement benefits represent the asset/liability associated with the expense recognition of SFAS 106 and the associated recovery of costs from customers. This has significantly increased

the Other Post Retirement Benefits net asset/liability since the conclusion of the Company's last BPU approved base rate case and is primarily due to the liability account decreasing since 2018 by approximately $800 million. See the testimony of Company witness Mr. McFadden for details on ways the Company has reduced its liability.

Energy Sales Tax and prepayments to the State of New Jersey for annual sales tax liability have been excluded from this analysis as they are included in the lead-lag study. The only prepayment included in this analysis is credit facilities fees. Special deposits represent the Company assets created as a result of the cumulative effect of annual pension funding in excess of SFAS No. 87 (pension accounting) expense and the timing of non-qualified pension costs.

The liability section of Schedule MJA-LL-3 includes the recognition of OPEB benefits as previously discussed.

The majority of the accounts payable amount reflects the recording of payables for contractors and other material and supply ("M&S") inventories. Since the other M&S balance is included as a separate component of Working Capital, it is necessary to reduce Working Capital requirements by the amounts included in other M&S inventory, which have not been paid.

PSE&G's net assets and liabilities analysis, as shown on Schedule MJA-LL-3 is $348,093,735 for electric and $261,255,338 for gas.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

MICHAEL J. ADAMS
SENIOR VICE PRESIDENT

Mr. Adams has over thirty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry.

While employed by Illinois Power Company, Mr. Adams monitored project expenditures associated with gas and electric distribution, transmission, and generation capital projects.

While employed by the Illinois Commerce Commission, Mr. Adams initially evaluated the rate filings of regulated utilities and provided expert testimony regarding the reasonableness of the requests. Mr. Adams was subsequently charged with developing and managing a management and operations audit program to evaluate company management policies, procedures, and performance, as well as operational efficiency and effectiveness. Mr. Adams served as the Deputy Executive Director of the agency at the time of his departure. As a consultant, Mr. Adams has provided consulting services to regulatory agencies and regulated utilities on an array of operational and financial issues since 1995.

Prior to joining Concentric, Mr. Adams was a Managing Director of Navigant Consulting, Inc. Mr. Adams is a Certified Public Accountant, a graduate of Illinois College and holds an M.B.A. from the University of Illinois, Springfield.

Mr. Adams provides financial, regulatory, strategic, operational and litigation support to his energy clients. He has assisted clients with regulatory/legislative initiatives related to the approval and implementation of alternative regulation plans as well as the preparation and support of regulatory filings under alternative rate plans. Mr. Adams also provides advisory services in the areas of mergers and acquisitions. As a consultant, Mr. Adams has provided expert testimony or reports before State and Federal regulatory agencies.

REPRESENTATIVE PROJECT EXPERIENCE

Audits/Special Studies

- Management audits
- Regulatory reviews/audits

- Project performance monitoring/reviews
- Prudence reviews
- Commission ordered studies
- Audit prep and support
- Project controls and assessments

Affiliate Transactions

- Code of Conduct
- Shared Services reviews
- Cost controls

Benchmarking

- O&M costs
- Capital expenditures
- Shared Services
- Operational performance
- Customer service
- Reliability

Due Diligence/Litigation/Special Projects

- Assessment of cost controls
- Financial outlook
- Historical/future performance assessment
- Merger Synergies
- Regulatory environment/assessment

Expert Witness

- Regulatory proceedings
- Civil litigation

Litigation Support

- Data review and analyses
- Position development and review
- Research
- Expert testimony and reports

Regulatory Proceedings

- Revenue Requirement
- Cash working capital
- Benchmarking
  - O&M
  - Capital
  - Shared Services
- Case development/management
- Multi-year rate plans
- Research
- Performance based regulation

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2007 – Present)
Senior Vice President
Vice President

Navigant Consulting, Inc. (1999 – 2007)
Managing Director

L.E. Burgess Consultants, Inc. (1995 – 1999)

Illinois Commerce Commission (1983 – 1995)
Accounting/Rate Case Staff
Director, Management Audit/Studies
Deputy Executive Director

Illinois Power Company (1981 – 1983)
Accounting/Auditing Department

EDUCATION

University of Illinois at Springfield
M.B.A., Finance

Illinois College
B.S., Accounting

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant
American Institute of Public Accountants
Illinois Society of Certified Public Accountants

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Liberty Utilities (Entrada Del Oro Sewer Company and Gold Canyon Sewer Company	2022	Liberty Utilities	SW-02519A-0235, SW-0362+A-21-0236, SW-04316A-21-0359	Indirect Overhead/Capitalization Rates
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2002	Arkansas Oklahoma Gas Corporation	02-024-U	Reasonableness of ratemaking Adjustments
CenterPoint Energy Arkla	2005	CenterPoint Energy Arkla	04-121-U	Cash Working Capital
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas	2013	Connecticut Natural Gas	13-06-08	Cash Working Capital
United Illuminating Company	2022	United Illuminating Company	22-08-08	Cash Working Capital
Federal Energy Regulatory Commission				
Granite State Gas Transmission	2010	Granite State Gas Transmission	RP10-896	Revenue Requirement
Georgia Public Service Commission				
Atlanta Gas Light Company	2019	Granite State Gas Transmission	42315	Cash Working Capital
Hawaii Public Utilities Commission				
Hawaii Electric Light Company, Inc.	2005	Hawaii Electric Light Company, Inc.	05-0315	Allowance for Funds Used During Construction
Idaho Public Utilities Commission				
Intermountain Gas Company	2016	Intermountain Gas Company	INT-G-16-2	Cash working capital, prepared/supported benchmarking for client

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Commerce Commission				
Illinois Power Company	1999	Illinois Power Company	99-0120/99-0134 (Cons.)	Functionalization/Unbundling of General and Intangible Assets and Administrative and General expenses.
Illinois Power Company	2004	Illinois Power Company	04-0476	Cash working capital and asset separation
Ameren Illinois Utilities	2006	Ameren Illinois Utilities	06-0070/06-0071/06-0072 (Cons.)	Functionalization of Assets, Cash Working Capital, Shared Services Costs, Benchmarking
Ameren Illinois Utilities	2007	Ameren Illinois Utilities	07-0585/07-0586/07-0587/ 07-0588/07-0589/07-0590 (Cons.)	Shared Services Costs, Asset Separation, Cash Working Capital
The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	2007	The Peoples Gas Light and Coke Company, Inc., and North Shore Gas Company	07-0241/07-0242 (Cons.)	Cash working capital
Northern Illinois Gas Company	2008	Northern Illinois Gas Company	08-0363	Cash working capital
Ameren Illinois	2015	Ameren Illinois	16-0262	Benchmarking of Utility Performance
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0645	Rider ZEA Reconciliation
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0103	Rider PE Reconciliation
Nicor Gas	2023	Nicor Gas		Cash working capital
Commonwealth Edison Company	2023	Commonwealth Edison Company	TBD	Cash working capital
Ameren Illinois	2023	Ameren Illinois	TBD	Assessment of MYRP
Kentucky Public Service Commission				
Kentucky Power Company	2023	Kentucky Power Company	2023-00159	Cash working capital
Maine Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Emera Maine	2017	Emera Maine	Docket No. 2017-00198	Cash working capital
Versant Power	2020	Versant Power	Docket No. 2020-00316	Cash working capital
Versant Power	2022	Versant Power	Docket No. 2022-00255	Cash working capital
Maryland Public Service Commission				
Constellation Energy	2009	Constellation Energy	Case No. 9173, Phase II	Shared Services, Benchmarking
Massachusetts Department of Public Utilities				
Massachusetts Distribution Companies	2002	Massachusetts Distribution Companies	DTE-99-84	Reliability standards and the appropriateness of utilizing data for benchmarking purposes
Missouri Public Service Commission				
AmerenUE (Union Electric Company)	2002	AmerenUE (Union Electric Company)	EC-2002-001	Cash working capital
AmerenUE	2003	AmerenUE	GR-2003-0517	Cash working capital
AmerenUE	2007	AmerenUE	ER-2007-0002	Cash working capital
AmerenUE	2008	AmerenUE	ER-2008-0318	Cash working capital
Missouri Gas Energy	2006	Missouri Gas Energy	GR-2006-0422	Cash working capital
Ameren Missouri Gas	2010	Ameren Missouri Gas	GR-2010-0363	Cash working capital
Ameren Missouri Electric	2010	Ameren Missouri Electric	ER-2011-0028	Cash working capital
Ameren Missouri	2012	Ameren Missouri	ER-2012-0166	Cash working capital
Ameren Missouri	2014	Ameren Missouri	ER-2014-0258	Affiliate transactions, Benchmarking
Evergy Metro, Inc.	2022	Evergy Metro, Inc.	ER-2022-0129	Cash working capital, Property Tax Tracker

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Evergy Missouri West, Inc.	2022	Evergy Missouri West, Inc.	ER-2022-0130	Cash working capital, Property Tax Tracker
Montana Public Service Commission				
Montana-Dakota Utilities	2022	Montana-Dakota Utilities	2022.11.XXXX	Cash working capital
New Hampshire Public Utilities Commission				
National Grid Energy North	2010	National Grid Energy North	DG 10-017	Revenue Requirement
New Mexico Public Regulation Commission				
New Mexico Gas Company	2019	New Mexico Gas Company	No. 19-00317-UT	Future Test Year Model / Revenue Requirement
State of New Jersey Board of Public Utilities				
PSEG	2018	PSEG	ER18010029 & GR18010030	Benchmarking
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	2003	Arkansas Oklahoma Gas Corporation	PUD200300088	Cash working capital
Ontario Energy Board				
Hydro One Distribution Business	2005	Hydro One Distribution Business	-	Cash working capital
Hydro One Transmission Business	2006	Hydro One Transmission Business	-	Cash working capital
Toronto Hydro	2006	Toronto Hydro	-	Cash working capital
Pennsylvania Public Utility Commission				
Allegheny Power	2004	Allegheny Power	M-00991220	Reliability data and reasonableness of established Standards
T.W. Phillips Gas and Oil Company, Inc.	2006	T.W. Phillips Gas and Oil Company, Inc.	R-00051178	Cash working capital
Tennessee Public Utility Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash working capital
Texas Public Utility Commission				
Texas-New Mexico Power Company	2008	Texas-New Mexico Power Company	36025	Revenue Requirement
El Paso Electric Company	2012	El Paso Electric Company	40094	O&M Benchmarking
El Paso Electric Company	2014	El Paso Electric Company	-	Benchmarking of New Generation Costs
El Paso Electric Company	2015	El Paso Electric Company	44941	Benchmarking of costs of new generation units
Virginia State Corporation Commission				
Virginia Natural Gas	2012	Virginia Natural Gas	PUE-2010-00142	Cash Working Capital
Virginia Natural Gas	2017	Virginia Natural Gas		Shared Services Review, Benchmarking, Cash Working Capital
Virginia Natural Gas	2022	Virginia Natural Gas	PUR-2022-00052	Cash working capital
West Virginia Public Service Commission				
Appalachian Power Company	2018	Appalachian Power Company	18-0646-E-42T	Cash working capital

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
Summary of Leads and Lag

Line No.	Description (A)	Days (B)	Workpaper Reference (C)
1	**Revenue Lag**		
2	Billing Lag	1.72	MJA-6
3	Service Lag	15.21	MJA-7
4	Collections Lag	50.65	MJA-7
5	Bank Float	0.92	MJA-7
6	Total Revenue Lag	68.50	MJA-7
7	**Expense Leads**		
8	Wages and Compensation	25.38	MJA-8
9	Pensions and Benefits		
10	401K	12.57	MJA-9
11	Group Life Insurance	15.03	MJA-9
12	Dental	2.94	MJA-9
13	Disability	45.89	MJA-9
14	Medical	12.86	MJA-9
15	OPEB	-	MJA-9
16	Pension	15.17	MJA-9
17	Workers Compensation	1.63	MJA-9
18	Other Operation and Maintenance	36.10	MJA-10
19	Purchased Power	35.83	MJA-11
20	Gas Suply Cost	35.63	MJA-12
21	Taxes Other than Income Tax		
22	Real Estate Taxes	(39.09)	MJA-13
23	Newark City Tax	75.46	MJA-13
24	Payroll Taxes	16.96	MJA-13
25	Income Taxes		
26	Federal Income Tax	37.88	MJA-14
27	State Income Tax (CBT)	(47.25)	MJA-14
28	Interest Expense	91.8	MJA-15
29	Service Company Expense	35.91	MJA-16
30	New Jersey Energy Sales Tax	(48.71)	MJA-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SUMMARY OF NET ASSETS AND LIABILITIES
REQUIRED FOR COST OF SERVICE
BASED ON THIRTEEN MONTH AVERAGE FOR THE PERIOD ENDING December 31, 2022
(THOUSANDS)

	Electric (1)	Gas (2)
Assets		
Other Accounts Receivable	$ 52,020	$ 14,156
Other Post Retirement Benefits	624,083	471,460
Prepayments	44,613	27,690
Special Deposits	20,740	15,668
Miscellaneous Deferred Debits	17,374	7,181
Total Assets	758,830	536,154
Liabilities		
Other Post Retirement Benefits	261,639	197,654
Current & Accrued Liabilities	90,878	68,653
Tax Collection Payable	(9)	(7)
Miscellaneous Current and Accrued Liabi	21,550	8,377
Other Deferred Credits	36,678	221
Total Liabilities	410,736	274,899
Net Asset / Liability	$ 348,094	$ 261,255

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022

(THOUSANDS)

Method	Electric	Gas	Total
(1)	(2)	(3)	(4)
1. Amount Required to Recover Cost of Service	$577,618	$344,066	$921,685
2. Net Assets and Liabilities	348,094	261,255	609,349
3. Total Other Cash Working Capital	$925,712	$605,322	$1,531,034

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SUMMARY OF NET CASH WORKING CAPITAL
REQUIRED FOR COST OF SERVICE
FOR THE TWELVE MONTHS ENDING May 31, 2024

	Electric			Gas		
	Adjusted Test Year Amount	Lag Days	Weighted Amount	Adjusted Test Year Amount	Lag Days	Weighted Amount
Revenue Requirment :						
Revenue Requirement	$ 4,485,865,209	68.50	$ 307,290,441,096	$ 2,566,052,779	68.50	$ 175,779,577,285
New Jersey Energy Sales Tax	294,876,355	68.50	20,199,600,539	146,348,329	68.50	10,025,143,544.87
Total Revenue Requirement	$ 4,780,741,565	68.50	$ 327,490,041,635	$ 2,712,401,108	68.50	$ 185,804,720,830
Requirements:						
Supply Costs	2,541,472,261	35.83	91,067,242,237	1,102,582,172	35.63	39,282,428,632
Salaries and Wages	214,492,436	25.38	5,442,765,970	197,982,333	25.38	5,023,820,534
Pension & Benefits						
Pension	(18,790,159)	15.17	(285,125,317)	(13,816,932)	15.17	(209,660,664)
OPEB	(11,645,238)	-	0	(9,613,439)	-	0
Medical Insurance	21,753,920	12.86	279,697,596	22,029,181	12.86	283,236,723
Dental Insurance	769,017	2.94	2,261,984	766,597	2.94	2,254,867
Group Life Insurance	230,622	15.03	3,465,815	227,809	15.03	3,423,535
Benefits Outside Services	0	-	0	0	-	0
Thrift and 401k Plans	5,875,210	12.57	73,822,855	5,823,587	12.57	73,174,210
Disability	487,103	45.89	22,355,013	478,576	45.89	21,963,673
Workers' Compensation	1,760,981	1.63	2,861,595	1,835,452	1.63	2,982,609
Total Pension&Benefits	441,457	225.00	99,339,540	7,730,831	22.90	177,374,952
Uncollectibles	93,118,344	-	0	34,511,985	-	0
Service Company Expense	118,811,220	35.91	4,266,598,397	93,831,173	35.91	3,369,546,498
Other O&M	497,736,182	36.10	17,969,565,288	254,824,443	36.10	9,199,822,379
Depreciation & Amortization	351,252,351	-	0	278,898,366	-	0
Subtotal Operating Expenses	1,060,918,097	21.00	22,236,163,685	662,065,966	19.00	$12,569,368,878
Income Taxes						
Federal	(8,452,208)	37.88	(320,127,383)	(56,859,842)	37.88	(2,153,566,523)
State	33,302,988	(47.25)	(1,573,566,161)	27,476,284	(47.25)	(1,298,254,399.65)
Total Income Taxes	24,850,779	(76.20)	(1,893,693,544)	(29,383,559)	117.50	(3,451,820,922.79)
Taxes Other Than Income	25,686,336	6.95	178,643,344	17,287,836	6.95	120,233,449
New Jersey Energy Sales Tax	294,876,355	(48.71)	(14,363,747,699)	146,348,329	(48.71)	(7,128,786,149)
Interest Expense	149,009,468	91.75	13,671,618,733	147,832,518	91.75	13,563,633,500
Operating Income	468,994,374	-	0	459,954,682	-	0
	938,566,534	(0.50)	(513,485,622)	771,423,365	8.50	6,555,080,800
Total Cost of Service Requirement	4,780,741,565	24.40	116,438,332,266	2,712,401,108	22.20	60,156,252,873
Average Daily Cost of Service Requirement	13,097,922			7,431,236		
Net Lag Days		44.10			46.30	
Cash Working Capital Requirement			$ 577,618,364			$ 344,066,223

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
METER READ AND BILL SCHEDULE

Billing Lag 1.72 days

Billing Lag for Non-Third Party Supplied Consolidated Bill Customers

Cycle (A)	Meter Read Date (B)	Schedule Bill Date (C)	Lag (D)
1	01/05/2022	01/06/2022	1.00
2	01/06/2022	01/07/2022	1.00
3	01/07/2022	01/10/2022	3.00
4	01/10/2022	01/11/2022	1.00
5	01/11/2022	01/12/2022	1.00
6	01/12/2022	01/13/2022	1.00
7	01/13/2022	01/14/2022	1.00
8	01/14/2022	01/18/2022	4.00
9	01/18/2022	01/19/2022	1.00
10	01/19/2022	01/20/2022	1.00
11	01/20/2022	01/21/2022	1.00
12	01/21/2022	01/22/2022	1.00
13	01/22/2022	01/24/2022	2.00
14	01/24/2022	01/25/2022	1.00
15	01/25/2022	01/26/2022	1.00
16	01/26/2022	01/27/2022	1.00
17	01/27/2022	01/28/2022	1.00
18	01/28/2022	01/31/2022	3.00
19	01/31/2022	02/01/2022	1.00
20	02/01/2022	02/02/2022	1.00
21	02/02/2022	02/03/2022	1.00
1	02/03/2022	02/04/2022	1.00
2	02/04/2022	02/07/2022	3.00
3	02/07/2022	02/08/2022	1.00
4	02/08/2022	02/09/2022	1.00
5	02/09/2022	02/10/2022	1.00
6	02/10/2022	02/11/2022	1.00
7	02/11/2022	02/14/2022	3.00
8	02/14/2022	02/15/2022	1.00
9	02/15/2022	02/16/2022	1.00
10	02/16/2022	02/17/2022	1.00
11	02/17/2022	02/18/2022	1.00
12	02/18/2022	02/22/2022	4.00
13	02/22/2022	02/23/2022	1.00
14	02/23/2022	02/24/2022	1.00
15	02/24/2022	02/25/2022	1.00
16	02/25/2022	02/28/2022	3.00
17	02/28/2022	03/01/2022	1.00
18	03/01/2022	03/02/2022	1.00
19	03/02/2022	03/03/2022	1.00
20	03/03/2022	03/04/2022	1.00
21	03/04/2022	03/07/2022	3.00
1	03/07/2022	03/08/2022	1.00
2	03/08/2022	03/09/2022	1.00
3	03/09/2022	03/10/2022	1.00
4	03/10/2022	03/11/2022	1.00
5	03/11/2022	03/14/2022	3.00
6	03/14/2022	03/15/2022	1.00
7	03/15/2022	03/16/2022	1.00
8	03/16/2022	03/17/2022	1.00
9	03/17/2022	03/18/2022	1.00
10	03/18/2022	03/21/2022	3.00
11	03/21/2022	03/22/2022	1.00
12	03/22/2022	03/23/2022	1.00
13	03/23/2022	03/24/2022	1.00
14	03/24/2022	03/25/2022	1.00
15	03/25/2022	03/28/2022	3.00

Billing Lag for Non-Third Party Supplied Consolidated Bill Customers

Cycle (A)	Meter Read Date (B)	Schedule Bill Date (C)	Lag (D)
16	03/28/2022	03/29/2022	1.00
17	03/29/2022	03/30/2022	1.00
18	03/30/2022	03/31/2022	1.00
19	03/31/2022	04/01/2022	1.00
20	04/01/2022	04/04/2022	3.00
21	04/04/2022	04/05/2022	1.00
1	04/05/2022	04/06/2022	1.00
2	04/06/2022	04/07/2022	1.00
3	04/07/2022	04/08/2022	1.00
4	04/08/2022	04/11/2022	3.00
5	04/11/2022	04/12/2022	1.00
6	04/12/2022	04/13/2022	1.00
7	04/13/2022	04/14/2022	1.00
8	04/14/2022	04/18/2022	4.00
9	04/18/2022	04/19/2022	1.00
10	04/19/2022	04/20/2022	1.00
11	04/20/2022	04/21/2022	1.00
12	04/21/2022	04/22/2022	1.00
13	04/22/2022	04/25/2022	3.00
14	04/25/2022	04/26/2022	1.00
15	04/26/2022	04/27/2022	1.00
16	04/27/2022	04/28/2022	1.00
17	04/28/2022	04/29/2022	1.00
18	04/29/2022	05/02/2022	3.00
19	05/01/2022	05/03/2022	2.00
20	05/02/2022	05/04/2022	2.00
21	05/03/2022	05/05/2022	2.00
1	05/05/2022	05/06/2022	1.00
2	05/06/2022	05/09/2022	3.00
3	05/09/2022	05/10/2022	1.00
4	05/10/2022	05/11/2022	1.00
5	05/11/2022	05/12/2022	1.00
6	05/12/2022	05/13/2022	1.00
7	05/13/2022	05/16/2022	3.00
8	05/16/2022	05/17/2022	1.00
9	05/17/2022	05/18/2022	1.00
10	05/18/2022	05/19/2022	1.00
11	05/19/2022	05/20/2022	1.00
12	05/20/2022	05/23/2022	3.00
13	05/23/2022	05/24/2022	1.00
14	05/24/2022	05/25/2022	1.00
15	05/25/2022	05/26/2022	1.00
16	05/26/2022	05/27/2022	1.00
17	05/27/2022	05/31/2022	4.00
18	05/31/2022	06/01/2022	1.00
19	06/01/2022	06/02/2022	1.00
20	06/02/2022	06/03/2022	1.00
21	06/03/2022	06/06/2022	3.00
1	06/06/2022	06/07/2022	1.00
2	06/07/2022	06/08/2022	1.00
3	06/08/2022	06/09/2022	1.00
4	06/09/2022	06/10/2022	1.00
5	06/10/2022	06/13/2022	3.00
6	06/13/2022	06/14/2022	1.00
7	06/14/2022	06/15/2022	1.00
8	06/15/2022	06/16/2022	1.00
9	06/16/2022	06/17/2022	1.00
10	06/17/2022	06/20/2022	3.00
11	06/20/2022	06/21/2022	1.00
12	06/21/2022	06/22/2022	1.00
13	06/22/2022	06/23/2022	1.00
14	06/23/2022	06/24/2022	1.00
15	06/24/2022	06/27/2022	3.00

Billing Lag for Non-Third Party Supplied Consolidated Bill Customers

Cycle (A)	Meter Read Date (B)	Schedule Bill Date (C)	Lag (D)
16	06/27/2022	06/28/2022	1.00
17	06/28/2022	06/29/2022	1.00
18	06/29/2022	06/30/2022	1.00
19	06/30/2022	07/01/2022	1.00
20	07/01/2022	07/05/2022	4.00
21	07/05/2022	07/06/2022	1.00
1	07/06/2022	07/07/2022	1.00
2	07/07/2022	07/08/2022	1.00
3	07/08/2022	07/11/2022	3.00
4	07/11/2022	07/12/2022	1.00
5	07/12/2022	07/13/2022	1.00
6	07/13/2022	07/14/2022	1.00
7	07/14/2022	07/15/2022	1.00
8	07/15/2022	07/18/2022	3.00
9	07/18/2022	07/19/2022	1.00
10	07/19/2022	07/20/2022	1.00
11	07/20/2022	07/21/2022	1.00
12	07/21/2022	07/22/2022	1.00
13	07/22/2022	07/25/2022	3.00
14	07/25/2022	07/26/2022	1.00
15	07/26/2022	07/27/2022	1.00
16	07/27/2022	07/28/2022	1.00
17	07/28/2022	07/29/2022	1.00
18	07/29/2022	08/01/2022	3.00
19	08/01/2022	08/02/2022	1.00
20	08/02/2022	08/03/2022	1.00
21	08/03/2022	08/04/2022	1.00
1	08/04/2022	08/05/2022	1.00
2	08/05/2022	08/08/2022	3.00
3	08/08/2022	08/09/2022	1.00
4	08/09/2022	08/10/2022	1.00
5	08/10/2022	08/11/2022	1.00
6	08/11/2022	08/12/2022	1.00
7	08/12/2022	08/15/2022	3.00
8	08/15/2022	08/16/2022	1.00
9	08/16/2022	08/17/2022	1.00
10	08/17/2022	08/18/2022	1.00
11	08/18/2022	08/19/2022	1.00
12	08/19/2022	08/22/2022	3.00
13	08/22/2022	08/23/2022	1.00
14	08/23/2022	08/24/2022	1.00
15	08/24/2022	08/25/2022	1.00
16	08/25/2022	08/26/2022	1.00
17	08/26/2022	08/29/2022	3.00
18	08/29/2022	08/30/2022	1.00
19	08/30/2022	08/31/2022	1.00
20	08/31/2022	09/01/2022	1.00
21	09/01/2022	09/02/2022	1.00
1	09/02/2022	09/06/2022	4.00
2	09/06/2022	09/07/2022	1.00
3	09/07/2022	09/08/2022	1.00
4	09/08/2022	09/09/2022	1.00
5	09/09/2022	09/12/2022	3.00
6	09/12/2022	09/13/2022	1.00
7	09/13/2022	09/14/2022	1.00
8	09/14/2022	09/15/2022	1.00
9	09/15/2022	09/16/2022	1.00
10	09/16/2022	09/19/2022	3.00
11	09/19/2022	09/20/2022	1.00
12	09/20/2022	09/21/2022	1.00
13	09/21/2022	09/22/2022	1.00
14	09/22/2022	09/23/2022	1.00
15	09/23/2022	09/26/2022	3.00

Billing Lag for Non-Third Party Supplied Consolidated Bill Customers

Cycle (A)	Meter Read Date (B)	Schedule Bill Date (C)	Lag (D)
16	09/26/2022	09/27/2022	1.00
17	09/27/2022	09/28/2022	1.00
18	09/28/2022	09/29/2022	1.00
19	09/29/2022	09/30/2022	1.00
20	09/30/2022	10/03/2022	3.00
21	10/03/2022	10/04/2022	1.00
1	10/04/2022	10/05/2022	1.00
2	10/05/2022	10/06/2022	1.00
3	10/06/2022	10/07/2022	1.00
4	10/07/2022	10/10/2022	3.00
5	10/10/2022	10/11/2022	1.00
6	10/11/2022	10/12/2022	1.00
7	10/12/2022	10/13/2022	1.00
8	10/13/2022	10/14/2022	1.00
9	10/14/2022	10/17/2022	3.00
10	10/17/2022	10/18/2022	1.00
11	10/18/2022	10/19/2022	1.00
12	10/19/2022	10/20/2022	1.00
13	10/20/2022	10/21/2022	1.00
14	10/21/2022	10/24/2022	3.00
15	10/24/2022	10/25/2022	1.00
16	10/25/2022	10/26/2022	1.00
17	10/26/2022	10/27/2022	1.00
18	10/27/2022	10/28/2022	1.00
19	10/28/2022	10/31/2022	3.00
20	10/31/2022	11/01/2022	1.00
21	11/01/2022	11/02/2022	1.00
1	11/02/2022	11/03/2022	1.00
2	11/03/2022	11/04/2022	1.00
3	11/04/2022	11/07/2022	3.00
4	11/07/2022	11/08/2022	1.00
5	11/08/2022	11/09/2022	1.00
6	11/09/2022	11/10/2022	1.00
7	11/10/2022	11/12/2022	2.00
8	11/12/2022	11/14/2022	2.00
9	11/14/2022	11/15/2022	1.00
10	11/15/2022	11/16/2022	1.00
11	11/16/2022	11/17/2022	1.00
12	11/17/2022	11/18/2022	1.00
13	11/18/2022	11/21/2022	3.00
14	11/21/2022	11/22/2022	1.00
15	11/22/2022	11/23/2022	1.00
16	11/23/2022	11/28/2022	5.00
17	11/28/2022	11/29/2022	1.00
18	11/29/2022	11/30/2022	1.00
19	11/30/2022	12/01/2022	1.00
20	12/01/2022	12/02/2022	1.00
21	12/02/2022	12/05/2022	3.00
1	12/05/2022	12/06/2022	1.00
2	12/06/2022	12/07/2022	1.00
3	12/07/2022	12/08/2022	1.00
4	12/08/2022	12/09/2022	1.00
5	12/09/2022	12/12/2022	3.00
6	12/12/2022	12/13/2022	1.00
7	12/13/2022	12/14/2022	1.00
8	12/14/2022	12/15/2022	1.00
9	12/15/2022	12/16/2022	1.00
10	12/16/2022	12/19/2022	3.00
11	12/19/2022	12/20/2022	1.00
12	12/20/2022	12/21/2022	1.00
13	12/21/2022	12/22/2022	1.00
14	12/22/2022	12/23/2022	1.00
15	12/23/2022	12/27/2022	4.00

Billing Lag for Non-Third Party Supplied Consolidated Bill Customers

Cycle (A)	Meter Read Date (B)	Schedule Bill Date (C)	Lag (D)
16	12/27/2022	12/28/2022	1.00
17	12/28/2022	12/29/2022	1.00
18	12/29/2022	12/30/2022	1.00
19	12/30/2022	01/03/2023	4.00
20	01/03/2023	01/04/2023	1.00
21	01/04/2023	01/05/2023	1.00
Average Billing Lag for Non-Third Party Supplied Consolidated Bill Customers			1.460

Average Lag Days for Third Party Supplied Customer	3.86
2022 Third Party Supplied Receivables as Percentage of Total Receivables	6.8%
	1.72

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
REVENUE LAG

Service Lag	15.21	
Billing Lag	1.72	
Collections Lag	50.65	
Bank Float	0.92	
Total	68.50	days

Service Lag		
Number of Days in Year:	365.00	
Average Number of Days in Month	30.42	
Mid Point of Average Number of Days in Month:	15.21	days

Bank Float	% Available	Weighted Lead
Same Day	8%	0.000
1 Day	92%	0.918
2+ Day	0.00%	0.000
		0.918

Aging Accounts Receivables

Month of	1-30	31-60	61-90	91-120	121-150	151-180	Over 180
October 2022	403,354,766	48,880,013	14,406,391	23,606,779	17,457,242	26,571,667	275,110,228
November 2022	453,500,466	42,217,226	32,129,525	10,554,771	19,800,288	15,387,216	270,541,407
December 2022	679,314,615	37,093,745	31,315,812	26,610,939	12,471,127	19,290,803	259,288,256
January 2023	788,677,191	44,347,766	28,012,620	26,866,028	21,953,025	14,438,354	257,101,376
February 2023	801,492,356	63,221,036	31,470,838	21,637,312	20,679,530	22,407,473	242,314,755
March 2023	748,260,730	84,577,917	41,721,839	25,169,587	18,724,069	19,458,821	237,149,202
April 2023	635,832,059	79,492,961	62,580,600	33,046,646	20,977,811	16,506,890	232,963,766
May 2023	495,096,239	62,846,027	53,658,675	47,820,243	29,965,211	16,154,004	218,900,370
June 2023	511,686,838	56,350,268	47,026,984	43,177,489	40,080,262	24,205,805	204,734,215
July 2023	632,655,701	51,118,795	40,489,886	40,978,389	34,650,228	36,741,871	204,419,135
August 2023	600,209,731	51,447,004	34,909,800	30,927,674	35,165,071	26,789,719	212,735,901
September 2023	591,676,678	71,620,921	36,576,568	28,295,436	25,590,942	29,858,122	209,945,405
Average	611,813,114	57,767,806	37,858,295	29,890,941	24,792,900	22,317,562	235,433,668
% of Total	59.99%	5.66%	3.71%	2.93%	2.43%	2.19%	23.08%
Midpoint [1]	15	45	75	105	120	120	120
Weighted Days	9.00	2.55	2.78	3.08	2.92	2.63	27.70
Total Days							50.65 days

[1] Capped at 120 days

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
PAYROLL

Wages and Compensation 25.38 days

Weekly Payroll (A)	Pay Period Beginning (B)	Pay Period End (C)	Paid On (D)	Net Pay (E)	Midpoint of Pay Period (F)	Payment Lead Time (G)	Total Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
Weekly	12/20/2021	12/26/2021	1/5/2022	$ 11,448,703	3.50	10.00	13.50	1.7%	0.23
Weekly	12/27/2021	1/2/2022	1/12/2022	11,146,259	3.50	10.00	13.50	1.7%	0.22
Weekly	1/3/2022	1/9/2022	1/19/2022	12,073,731	3.50	10.00	13.50	1.8%	0.24
Weekly	1/10/2022	1/16/2022	1/26/2022	12,483,559	3.50	10.00	13.50	1.9%	0.25
Weekly	1/17/2022	1/23/2022	2/2/2022	14,082,124	3.50	10.00	13.50	2.1%	0.28
Weekly	1/24/2022	1/30/2022	2/9/2022	13,522,619	3.50	10.00	13.50	2.0%	0.27
Weekly	1/31/2022	2/6/2022	2/16/2022	12,606,068	3.50	10.00	13.50	1.9%	0.25
Weekly	2/7/2022	2/13/2022	2/23/2022	12,531,189	3.50	10.00	13.50	1.9%	0.25
Weekly	2/14/2022	2/20/2022	3/2/2022	12,487,438	3.50	10.00	13.50	1.9%	0.25
Weekly	2/21/2022	2/27/2022	3/9/2022	12,648,916	3.50	10.00	13.50	1.9%	0.25
Weekly	2/28/2022	3/6/2022	3/16/2022	12,562,015	3.50	10.00	13.50	1.9%	0.25
Weekly	3/7/2022	3/13/2022	3/23/2022	12,947,237	3.50	10.00	13.50	1.9%	0.26
Weekly	3/14/2022	3/20/2022	3/30/2022	12,727,949	3.50	10.00	13.50	1.9%	0.25
Weekly	3/21/2022	3/27/2022	4/6/2022	12,623,910	3.50	10.00	13.50	1.9%	0.25
Weekly	3/28/2022	4/3/2022	4/13/2022	12,843,569	3.50	10.00	13.50	1.9%	0.26
Weekly	4/4/2022	4/10/2022	4/20/2022	12,678,489	3.50	10.00	13.50	1.9%	0.25
Weekly	4/11/2022	4/17/2022	4/27/2022	12,408,211	3.50	10.00	13.50	1.8%	0.25
Weekly	4/18/2022	4/24/2022	5/4/2022	12,763,774	3.50	10.00	13.50	1.9%	0.26
Weekly	4/25/2022	5/1/2022	5/11/2022	12,498,811	3.50	10.00	13.50	1.9%	0.25
Weekly	5/2/2022	5/8/2022	5/18/2022	12,744,477	3.50	10.00	13.50	1.9%	0.26
Weekly	5/9/2022	5/15/2022	5/25/2022	13,707,998	3.50	10.00	13.50	2.0%	0.27
Weekly	5/16/2022	5/22/2022	6/1/2022	13,565,082	3.50	10.00	13.50	2.0%	0.27
Weekly	5/23/2022	5/29/2022	6/8/2022	12,991,855	3.50	10.00	13.50	1.9%	0.26
Weekly	5/30/2022	6/5/2022	6/15/2022	13,284,295	3.50	10.00	13.50	2.0%	0.27
Weekly	6/6/2022	6/12/2022	6/22/2022	13,269,142	3.50	10.00	13.50	2.0%	0.27
Weekly	6/13/2022	6/19/2022	6/29/2022	12,958,138	3.50	10.00	13.50	1.9%	0.26
Weekly	6/20/2022	6/26/2022	7/6/2022	12,935,632	3.50	10.00	13.50	1.9%	0.26
Weekly	6/27/2022	7/3/2022	7/13/2022	12,374,965	3.50	10.00	13.50	1.8%	0.25
Weekly	7/4/2022	7/10/2022	7/20/2022	12,989,833	3.50	10.00	13.50	1.9%	0.26
Weekly	7/11/2022	7/17/2022	7/27/2022	13,053,078	3.50	10.00	13.50	1.9%	0.26
Weekly	7/18/2022	7/24/2022	8/3/2022	13,315,323	3.50	10.00	13.50	2.0%	0.27
Weekly	7/25/2022	7/31/2022	8/10/2022	13,017,872	3.50	10.00	13.50	1.9%	0.26
Weekly	8/1/2022	8/7/2022	8/17/2022	13,084,111	3.50	10.00	13.50	1.9%	0.26
Weekly	8/8/2022	8/14/2022	8/24/2022	13,065,992	3.50	10.00	13.50	1.9%	0.26
Weekly	8/15/2022	8/21/2022	8/31/2022	13,110,084	3.50	10.00	13.50	1.9%	0.26
Weekly	8/22/2022	8/28/2022	9/7/2022	12,916,915	3.50	10.00	13.50	1.9%	0.26
Weekly	8/29/2022	9/4/2022	9/14/2022	12,475,814	3.50	10.00	13.50	1.8%	0.25
Weekly	9/5/2022	9/11/2022	9/21/2022	12,884,859	3.50	10.00	13.50	1.9%	0.26
Weekly	9/12/2022	9/18/2022	9/28/2022	13,272,968	3.50	10.00	13.50	2.0%	0.27
Weekly	9/19/2022	9/25/2022	10/5/2022	13,091,657	3.50	10.00	13.50	1.9%	0.26
Weekly	9/26/2022	10/2/2022	10/12/2022	13,154,478	3.50	10.00	13.50	2.0%	0.26
Weekly	10/3/2022	10/9/2022	10/19/2022	13,567,056	3.50	10.00	13.50	2.0%	0.27
Weekly	10/10/2022	10/16/2022	10/26/2022	13,428,385	3.50	10.00	13.50	2.0%	0.27
Weekly	10/17/2022	10/23/2022	11/2/2022	13,712,786	3.50	10.00	13.50	2.0%	0.27
Weekly	10/24/2022	10/30/2022	11/9/2022	13,620,268	3.50	10.00	13.50	2.0%	0.27
Weekly	10/31/2022	11/6/2022	11/16/2022	13,294,465	3.50	10.00	13.50	2.0%	0.27
Weekly	11/7/2022	11/13/2022	11/23/2022	13,431,289	3.50	10.00	13.50	2.0%	0.27
Weekly	11/14/2022	11/20/2022	11/30/2022	14,166,404	3.50	10.00	13.50	2.1%	0.28
Weekly	11/21/2022	11/27/2022	12/7/2022	12,429,280	3.50	10.00	13.50	1.8%	0.25
Weekly	11/28/2022	12/4/2022	12/14/2022	13,555,097	3.50	10.00	13.50	2.0%	0.27
Weekly	12/5/2022	12/11/2022	12/21/2022	13,418,743	3.50	10.00	13.50	2.0%	0.27
Weekly	12/12/2022	12/18/2022	12/28/2022	13,496,184	3.50	10.00	13.50	2.0%	0.27
				$ 674,469,096					13.50

Bi-Weekly Payroll (A)	Pay Period Beginning (B)	Pay Period End (C)	Paid On (D)	Net Pay (E)	Midpoint of Pay Period (F)	Payment Lead Time (G)	Total Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
Bi-Weekly	12/13/2021	12/26/2021	1/5/2022	$ 9,655,088	7.00	10.00	17.00	3.5%	0.60
Bi-Weekly	12/27/2021	1/9/2022	1/19/2022	9,593,405	7.00	10.00	17.00	3.5%	0.59
Bi-Weekly	1/10/2022	1/23/2022	2/2/2022	10,256,481	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	1/24/2022	2/6/2022	2/16/2022	11,155,994	7.00	10.00	17.00	4.1%	0.69
Bi-Weekly	2/7/2022	2/20/2022	3/2/2022	9,503,780	7.00	10.00	17.00	3.5%	0.59
Bi-Weekly	2/21/2022	3/6/2022	3/16/2022	10,006,267	7.00	10.00	17.00	3.6%	0.62
Bi-Weekly	3/7/2022	3/20/2022	3/30/2022	10,091,329	7.00	10.00	17.00	3.7%	0.62
Bi-Weekly	3/21/2022	4/3/2022	4/13/2022	10,393,708	7.00	10.00	17.00	3.8%	0.64
Bi-Weekly	4/4/2022	4/17/2022	4/27/2022	21,423,810	7.00	10.00	17.00	7.8%	1.32
Bi-Weekly	4/18/2022	5/1/2022	5/11/2022	10,116,132	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	5/2/2022	5/15/2022	5/25/2022	9,992,702	7.00	10.00	17.00	3.6%	0.62
Bi-Weekly	5/16/2022	5/29/2022	6/8/2022	9,997,887	7.00	10.00	17.00	3.6%	0.62
Bi-Weekly	5/30/2022	6/12/2022	6/22/2022	10,022,269	7.00	10.00	17.00	3.6%	0.62
Bi-Weekly	6/13/2022	6/26/2022	7/6/2022	10,080,252	7.00	10.00	17.00	3.7%	0.62
Bi-Weekly	6/27/2022	7/10/2022	7/20/2022	9,891,614	7.00	10.00	17.00	3.6%	0.61
Bi-Weekly	7/11/2022	7/24/2022	8/3/2022	10,281,945	7.00	10.00	17.00	3.7%	0.64
Bi-Weekly	7/25/2022	8/7/2022	8/17/2022	10,137,939	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	8/8/2022	8/21/2022	8/31/2022	10,205,291	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	8/22/2022	9/4/2022	9/14/2022	9,959,323	7.00	10.00	17.00	3.6%	0.62
Bi-Weekly	9/5/2022	9/18/2022	9/28/2022	10,156,336	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	9/19/2022	10/2/2022	10/12/2022	10,151,016	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	10/3/2022	10/16/2022	10/26/2022	10,202,441	7.00	10.00	17.00	3.7%	0.63
Bi-Weekly	10/17/2022	10/30/2022	11/9/2022	10,284,936	7.00	10.00	17.00	3.7%	0.64
Bi-Weekly	10/31/2022	11/13/2022	11/23/2022	10,064,927	7.00	10.00	17.00	3.7%	0.62
Bi-Weekly	11/14/2022	11/27/2022	12/7/2022	10,067,470	7.00	10.00	17.00	3.7%	0.62
Bi-Weekly	11/28/2022	12/11/2022	12/21/2022	11,260,205	7.00	10.00	17.00	4.1%	0.70
				$ 274,952,547					17.00

Incentive Compensation (A)	Pay Period Beginning (B)	Pay Period End (C)	Paid On (D)	Net Pay (E)	Midpoint of Pay Period (F)	Payment Lead Time (G)	Total Lead Time (H)
Incentive Compensation	1/1/2021	12/31/2021	3/2/2022	47,276,300	182.50	61.00	243.50

	Amount	Expense Lead	Weighting	Weighted Lead
Weekly	$ 674,469,096	13.50	67.7%	9.14
Bi-Weekly	274,952,547	17.00	27.6%	4.69
Incentive Compensation	47,276,300	243.50	4.7%	11.55
Weighted Lead for payroll and incentive compensation	$ 996,697,943			25.38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
EMPLOYEE BENEFITS

SUMMARY

Category	Weighted Lead
401K	12.57 days
Group Life Insurance	15.03 days
Dental	2.94 days
Disability	45.89 days
Medical	12.86 days
OPEB	0.00 days
Pension	15.17 days
Workers Compensation	1.63 days

Short-Term Disability (A)	Service Start Date (B)	Service End Date (C)	Payment Date (D)	Payment Amount (E)	Service Lead Time (F)	Processing Lead Time (G)	Total Unweighted Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
First Quarter	1/1/2022	3/31/2022	5/12/2022	$ 304,426	45.00	42.00	87.00	24.62%	21.42
Second Quarter	4/1/2022	6/30/2022	8/12/2022	293,984	45.50	43.00	88.50	23.78%	21.04
Third Quarter	7/1/2022	9/30/2022	1/6/2023	320,199	46.00	98.00	144.00	25.90%	37.29
Fourth Quarter	10/1/2022	12/31/2022	3/13/2023	317,831	46.00	72.00	118.00	25.71%	30.33
				$ 1,236,439					110.09

Long-Term Disability (A)	Service Start Date (B)	Service End Date (C)	Payment Date (D)	Payment Amount (E)	Service Lead Time (F)	Processing Lead Time (G)	Total Unweighted Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
January 2022	1/1/2022	1/31/2022	1/31/2022	$ 220,000	15.50	-	15.50	9%	1.32
February 2022	2/1/2022	2/28/2022	2/28/2022	230,948	14.00	-	14.00	9%	1.26
March 2022	3/1/2022	3/31/2022	3/31/2022	218,461	15.50	-	15.50	8%	1.32
April 2022	4/1/2022	4/30/2022	4/29/2022	185,114	15.00	(1.00)	14.00	7%	1.01
May 2022	5/1/2022	5/31/2022	5/31/2022	224,223	15.50	-	15.50	9%	1.35
June 2022	6/1/2022	6/30/2022	7/1/2022	222,257	15.00	1.00	16.00	9%	1.38
July 2022	7/1/2022	7/31/2022	7/28/2022	212,546	15.50	(3.00)	12.50	8%	1.03
August 2022	8/1/2022	8/31/2022	9/1/2022	221,203	15.50	1.00	16.50	9%	1.42
September 2022	9/1/2022	9/30/2022	9/30/2022	185,450	15.00	-	15.00	7%	1.08
October 2022	10/1/2022	10/31/2022	11/1/2022	221,663	15.50	1.00	16.50	9%	1.42
November 2022	11/1/2022	11/30/2022	12/1/2022	221,144	15.00	1.00	16.00	9%	1.37
December 2022	12/1/2022	12/31/2022	12/29/2022	211,761	15.50	(2.00)	13.50	8%	1.11
				$ 2,574,769.36					15.07

	Amount	Expense Lead	Weighting	Weighted Lead
	$ 1,236,439	110.09	32.4%	35.71
	$ 2,574,769	15.07	67.6%	10.18
Weighted Lead for ST and LT Disability				45.89

Workers Compensation	Service Start Date	Service End Date	Payment Date	Payment Amount	Service Lead Time	Processing Lead Time	Total Unweighted Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
First Quarter	1/1/2022	3/31/2022	1/20/2022	$ 151,908	45.00	(70.00)	(25.00)	25%	(6.25)
Second Quarter	4/1/2022	6/30/2022	6/2/2022	151908	45.50	(28.00)	17.50	25%	4.38
Third Quarter	7/1/2022	9/30/2022	8/8/2022	151908	46.00	(53.00)	(7.00)	25%	(1.75)
Fourth Quarter	10/1/2022	12/31/2022	12/6/2022	151908	46.00	(25.00)	21.00	25%	5.25
				$ 607,630					1.63

401K Matching	Service Start Date	Service End Date	Payment Date	Payment Amount	Service Lead Time	Processing Lead Time	Total Unweighted Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
January 2022	1/1/2022	1/31/2022	1/28/2022	$ 3,052,413	15.50	(3.00)	12.50	7.3%	0.91
February 2022	2/1/2022	2/28/2022	2/25/2022	3,244,130	14.00	(3.00)	11.00	7.7%	0.85
March 2022	3/1/2022	3/31/2022	3/31/2022	6,656,599	15.50	-	15.50	15.8%	2.46
April 2022	4/1/2022	4/30/2022	4/28/2022	3,132,525	15.00	(2.00)	13.00	7.5%	0.97
May 2022	5/1/2022	5/31/2022	5/26/2022	3,244,369	15.50	(5.00)	10.50	7.7%	0.81
June 2022	6/1/2022	6/30/2022	6/30/2022	3,532,557	15.00	-	15.00	8.4%	1.26
July 2022	7/1/2022	7/31/2022	7/28/2022	3,002,269	15.50	(3.00)	12.50	7.1%	0.89
August 2022	8/1/2022	8/31/2022	8/25/2022	2,984,530	15.50	(6.00)	9.50	7.1%	0.68
September 2022	9/1/2022	9/30/2022	9/29/2022	4,001,910	15.00	(1.00)	14.00	9.5%	1.33
October 2022	10/1/2022	10/31/2022	10/27/2022	3,062,103	15.50	(4.00)	11.50	7.3%	0.84
November 2022	11/1/2022	11/30/2022	11/23/2022	2,973,160	15.00	(7.00)	8.00	7.1%	0.57
December 2022	12/1/2022	12/31/2022	12/29/2022	3,115,719	15.50	(2.00)	13.50	7.4%	1.00
				$ 42,002,283					12.57

Dental	Service Start Date	Service End Date	Payment Date	Payment Amount	Service Lead Time	Processing Lead Time	Total Unweighted Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Delta ASO	1/1/2022	1/31/2022	1/31/2022	$ 168	15.50	-	15.50	0.00%	0.00
Delta ASO	2/1/2022	2/28/2022	2/28/2022	161	14.00	-	14.00	0.00%	0.00
Delta ASO	3/1/2022	3/31/2022	3/31/2022	13	15.50	-	15.50	0.00%	0.00
Delta Claims	12/1/2021	12/31/2021	3/15/2022	1,829	15.50	74.00	89.50	0.02%	0.02
Delta Claims	1/1/2022	1/31/2022	3/15/2022	339	15.50	43.00	58.50	0.00%	0.00
Delta Claims	2/1/2022	2/28/2022	4/1/2022	334	14.00	32.00	46.00	0.00%	0.00
Delta Claims	3/1/2022	3/30/2022	5/20/2022	1,058	15.00	51.00	66.00	0.01%	0.01
Delta Claims	4/1/2022	4/30/2022	6/3/2022	1,009	15.00	34.00	49.00	0.01%	0.01
Aetna Claims	1/5/2022	1/5/2022	1/6/2022	53,917	0.50	1.00	1.50	0.71%	0.01
Aetna Claims	1/6/2022	1/6/2022	1/7/2022	20,406	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	1/7/2022	1/7/2022	1/10/2022	29,487	0.50	3.00	3.50	0.39%	0.01
Aetna Claims	1/11/2022	1/11/2022	1/12/2022	37,823	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	1/12/2022	1/12/2022	1/13/2022	41,328	0.50	1.00	1.50	0.54%	0.01
Aetna Claims	1/14/2022	1/14/2022	1/18/2022	29,205	0.50	4.00	4.50	0.38%	0.02
Aetna Claims	1/18/2022	1/18/2022	1/19/2022	22,544	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	1/19/2022	1/19/2022	1/20/2022	59,201	0.50	1.00	1.50	0.78%	0.01
Aetna Claims	1/20/2022	1/20/2022	1/21/2022	25,589	0.50	1.00	1.50	0.34%	0.01

Aetna Claims	1/24/2022	1/24/2022	1/25/2022	31,128	0.50	1.00	1.50	0.41%	0.01
Aetna Claims	1/26/2022	1/26/2022	1/27/2022	88,694	0.50	1.00	1.50	1.17%	0.02
Aetna Claims	1/28/2022	1/28/2022	1/31/2022	43,721	0.50	3.00	3.50	0.58%	0.02
Aetna Claims	2/1/2022	2/1/2022	2/2/2022	44,550	0.50	1.00	1.50	0.59%	0.01
Aetna Claims	2/2/2022	2/2/2022	2/3/2022	48,867	0.50	1.00	1.50	0.64%	0.01
Aetna Claims	2/4/2022	2/4/2022	2/7/2022	38,442	0.50	3.00	3.50	0.51%	0.02
Aetna Claims	2/7/2022	2/7/2022	2/8/2022	21,833	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	2/8/2022	2/8/2022	2/9/2022	29,787	0.50	1.00	1.50	0.39%	0.01
Aetna Claims	2/9/2022	2/9/2022	2/10/2022	67,064	0.50	1.00	1.50	0.88%	0.01
Aetna Claims	2/10/2022	2/10/2022	2/11/2022	23,443	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	2/11/2022	2/11/2022	2/14/2022	26,485	0.50	3.00	3.50	0.35%	0.01
Aetna Claims	2/15/2022	2/15/2022	2/16/2022	38,976	0.50	1.00	1.50	0.51%	0.01
Aetna Claims	2/16/2022	2/16/2022	2/17/2022	55,111	0.50	1.00	1.50	0.73%	0.01
Aetna Claims	2/17/2022	2/17/2022	2/18/2022	25,488	0.50	1.00	1.50	0.34%	0.01
Aetna Claims	2/18/2022	2/18/2022	2/22/2022	23,517	0.50	4.00	4.50	0.31%	0.01
Aetna Claims	2/22/2022	2/22/2022	2/23/2022	24,900	0.50	1.00	1.50	0.33%	0.00
Aetna Claims	2/23/2022	2/23/2022	2/24/2022	71,666	0.50	1.00	1.50	0.94%	0.01
Aetna Claims	2/24/2022	2/24/2022	2/25/2022	38,804	0.50	1.00	1.50	0.51%	0.01
Aetna Claims	2/25/2022	2/25/2022	2/28/2022	26,628	0.50	3.00	3.50	0.35%	0.01
Aetna Claims	3/1/2022	3/1/2022	3/2/2022	39,854	0.50	1.00	1.50	0.52%	0.01
Aetna Claims	3/2/2022	3/2/2022	3/3/2022	69,969	0.50	1.00	1.50	0.92%	0.01
Aetna Claims	3/3/2022	3/3/2022	3/4/2022	26,882	0.50	1.00	1.50	0.35%	0.01
Aetna Claims	3/4/2022	3/4/2022	3/7/2022	29,850	0.50	3.00	3.50	0.39%	0.01
Aetna Claims	3/8/2022	3/8/2022	3/9/2022	47,711	0.50	1.00	1.50	0.63%	0.01
Aetna Claims	3/9/2022	3/9/2022	3/10/2022	82,263	0.50	1.00	1.50	1.08%	0.02
Aetna Claims	3/10/2022	3/10/2022	3/11/2022	26,656	0.50	1.00	1.50	0.35%	0.01
Aetna Claims	3/11/2022	3/11/2022	3/14/2022	24,406	0.50	3.00	3.50	0.32%	0.01
Aetna Claims	3/15/2022	3/15/2022	3/16/2022	50,776	0.50	1.00	1.50	0.67%	0.01
Aetna Claims	3/16/2022	3/16/2022	3/17/2022	65,086	0.50	1.00	1.50	0.86%	0.01
Aetna Claims	3/17/2022	3/17/2022	3/18/2022	22,635	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	3/21/2022	3/21/2022	3/22/2022	37,568	0.50	1.00	1.50	0.49%	0.01
Aetna Claims	3/22/2022	3/22/2022	3/23/2022	21,055	0.50	1.00	1.50	0.28%	0.00
Aetna Claims	3/23/2022	3/23/2022	3/24/2022	62,313	0.50	1.00	1.50	0.82%	0.01
Aetna Claims	3/24/2022	3/24/2022	3/25/2022	22,177	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	3/25/2022	3/25/2022	3/28/2022	23,861	0.50	3.00	3.50	0.31%	0.01
Aetna Claims	3/29/2022	3/29/2022	3/30/2022	38,011	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	3/30/2022	3/30/2022	3/31/2022	76,594	0.50	1.00	1.50	1.01%	0.02
Aetna Claims	3/31/2022	3/31/2022	4/6/2022	36,312	0.50	6.00	6.50	0.48%	0.03
Aetna Claims	4/1/2022	4/1/2022	4/4/2022	23,162	0.50	3.00	3.50	0.31%	0.01
Aetna Claims	4/4/2022	4/4/2022	4/5/2022	21,253	0.50	1.00	1.50	0.28%	0.00
Aetna Claims	4/5/2022	4/5/2022	4/6/2022	33,674	0.50	1.00	1.50	0.44%	0.01
Aetna Claims	4/6/2022	4/6/2022	4/7/2022	51,175	0.50	1.00	1.50	0.67%	0.01
Aetna Claims	4/7/2022	4/7/2022	4/8/2022	28,872	0.50	1.00	1.50	0.38%	0.01
Aetna Claims	4/8/2022	4/8/2022	4/11/2022	28,210	0.50	3.00	3.50	0.37%	0.01
Aetna Claims	4/12/2022	4/12/2022	4/13/2022	49,024	0.50	1.00	1.50	0.65%	0.01
Aetna Claims	4/13/2022	4/13/2022	4/14/2022	64,336	0.50	1.00	1.50	0.85%	0.01
Aetna Claims	4/14/2022	4/14/2022	4/15/2022	20,328	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	4/18/2022	4/18/2022	4/19/2022	41,131	0.50	1.00	1.50	0.54%	0.01
Aetna Claims	4/19/2022	4/19/2022	4/20/2022	27,442	0.50	1.00	1.50	0.36%	0.01
Aetna Claims	4/20/2022	4/20/2022	4/21/2022	63,283	0.50	1.00	1.50	0.83%	0.01
Aetna Claims	4/21/2022	4/21/2022	4/22/2022	29,776	0.50	1.00	1.50	0.39%	0.01
Aetna Claims	4/22/2022	4/22/2022	4/25/2022	20,437	0.50	3.00	3.50	0.27%	0.01

Aetna Claims	4/25/2022	4/25/2022	4/26/2022	22,160	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	4/26/2022	4/26/2022	4/27/2022	27,943	0.50	1.00	1.50	0.37%	0.01
Aetna Claims	4/27/2022	4/27/2022	4/28/2022	66,315	0.50	1.00	1.50	0.87%	0.01
Aetna Claims	4/28/2022	4/28/2022	4/29/2022	29,501	0.50	1.00	1.50	0.39%	0.01
Aetna Claims	5/2/2022	5/2/2022	5/3/2022	34,373	0.50	1.00	1.50	0.45%	0.01
Aetna Claims	5/3/2022	5/3/2022	5/4/2022	36,862	0.50	1.00	1.50	0.49%	0.01
Aetna Claims	5/4/2022	5/4/2022	5/5/2022	64,369	0.50	1.00	1.50	0.85%	0.01
Aetna Claims	5/5/2022	5/5/2022	5/6/2022	25,936	0.50	1.00	1.50	0.34%	0.01
Aetna Claims	5/9/2022	5/9/2022	5/10/2022	37,418	0.50	1.00	1.50	0.49%	0.01
Aetna Claims	5/10/2022	5/10/2022	5/11/2022	27,513	0.50	1.00	1.50	0.36%	0.01
Aetna Claims	5/11/2022	5/11/2022	5/12/2022	65,759	0.50	1.00	1.50	0.87%	0.01
Aetna Claims	5/12/2022	5/12/2022	5/13/2022	26,846	0.50	1.00	1.50	0.35%	0.01
Aetna Claims	5/13/2022	5/13/2022	5/16/2022	21,765	0.50	3.00	3.50	0.29%	0.01
Aetna Claims	5/17/2022	5/17/2022	5/18/2022	29,758	0.50	1.00	1.50	0.39%	0.01
Aetna Claims	5/18/2022	5/18/2022	5/19/2022	59,345	0.50	1.00	1.50	0.78%	0.01
Aetna Claims	5/19/2022	5/19/2022	5/20/2022	23,351	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	5/23/2022	5/23/2022	5/24/2022	29,840	0.50	1.00	1.50	0.39%	0.01
Aetna Claims	5/25/2022	5/25/2022	5/26/2022	77,628	0.50	1.00	1.50	1.02%	0.02
Aetna Claims	5/26/2022	5/26/2022	5/27/2022	28,133	0.50	1.00	1.50	0.37%	0.01
Aetna Claims	5/27/2022	5/27/2022	5/31/2022	22,464	0.50	4.00	4.50	0.30%	0.01
Aetna Claims	6/1/2022	6/1/2022	6/2/2022	74,874	0.50	1.00	1.50	0.99%	0.01
Aetna Claims	6/2/2022	6/2/2022	6/3/2022	22,983	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	6/3/2022	6/3/2022	6/6/2022	22,506	0.50	3.00	3.50	0.30%	0.01
Aetna Claims	6/6/2022	6/6/2022	6/7/2022	21,870	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	6/8/2022	6/8/2022	6/9/2022	74,346	0.50	1.00	1.50	0.98%	0.01
Aetna Claims	6/9/2022	6/9/2022	6/10/2022	23,067	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	6/10/2022	6/10/2022	6/13/2022	23,599	0.50	3.00	3.50	0.31%	0.01
Aetna Claims	6/14/2022	6/14/2022	6/15/2022	41,440	0.50	1.00	1.50	0.55%	0.01
Aetna Claims	6/15/2022	6/15/2022	6/16/2022	61,997	0.50	1.00	1.50	0.82%	0.01
Aetna Claims	6/16/2022	6/16/2022	6/17/2022	21,755	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	6/21/2022	6/21/2022	6/22/2022	34,976	0.50	1.00	1.50	0.46%	0.01
Aetna Claims	6/22/2022	6/22/2022	6/23/2022	67,227	0.50	1.00	1.50	0.89%	0.01
Aetna Claims	6/23/2022	6/23/2022	6/24/2022	22,477	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	6/24/2022	6/24/2022	6/27/2022	22,814	0.50	3.00	3.50	0.30%	0.01
Aetna Claims	6/28/2022	6/28/2022	6/29/2022	40,260	0.50	1.00	1.50	0.53%	0.01
Aetna Claims	6/29/2022	6/29/2022	6/30/2022	62,140	0.50	1.00	1.50	0.82%	0.01
Aetna Claims	6/30/2022	6/30/2022	7/1/2022	25,903	0.50	1.00	1.50	0.34%	0.01
Aetna Claims	7/1/2022	7/1/2022	7/5/2022	18,051	0.50	4.00	4.50	0.24%	0.01
Aetna Claims	7/6/2022	7/6/2022	7/7/2022	76,123	0.50	1.00	1.50	1.00%	0.02
Aetna Claims	7/7/2022	7/7/2022	7/8/2022	24,220	0.50	1.00	1.50	0.32%	0.00
Aetna Claims	7/8/2022	7/8/2022	7/12/2022	24,862	0.50	4.00	4.50	0.33%	0.01
Aetna Claims	7/11/2022	7/11/2022	7/12/2022	21,076	0.50	1.00	1.50	0.28%	0.00
Aetna Claims	7/12/2022	7/12/2022	7/13/2022	20,728	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	7/13/2022	7/13/2022	7/22/2022	56,261	0.50	9.00	9.50	0.74%	0.07
Aetna Claims	7/14/2022	7/14/2022	7/15/2022	24,653	0.50	1.00	1.50	0.32%	0.00
Aetna Claims	7/18/2022	7/18/2022	7/19/2022	33,273	0.50	1.00	1.50	0.44%	0.01
Aetna Claims	7/19/2022	7/19/2022	7/20/2022	27,572	0.50	1.00	1.50	0.36%	0.01
Aetna Claims	7/20/2022	7/20/2022	7/21/2022	55,521	0.50	1.00	1.50	0.73%	0.01
Aetna Claims	7/21/2022	7/21/2022	7/22/2022	25,944	0.50	1.00	1.50	0.34%	0.01
Aetna Claims	7/25/2022	7/25/2022	7/26/2022	31,722	0.50	1.00	1.50	0.42%	0.01
Aetna Claims	7/26/2022	7/26/2022	7/27/2022	27,329	0.50	1.00	1.50	0.36%	0.01
Aetna Claims	7/27/2022	7/27/2022	7/28/2022	46,768	0.50	1.00	1.50	0.62%	0.01

Aetna Claims	7/28/2022	7/28/2022	7/29/2022	22,307	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	8/1/2022	8/1/2022	8/2/2022	33,794	0.50	1.00	1.50	0.45%	0.01
Aetna Claims	8/2/2022	8/2/2022	8/3/2022	20,835	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	8/3/2022	8/3/2022	8/4/2022	40,006	0.50	1.00	1.50	0.53%	0.01
Aetna Claims	8/4/2022	8/4/2022	8/5/2022	23,349	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	8/5/2022	8/5/2022	8/8/2022	23,271	0.50	3.00	3.50	0.31%	0.01
Aetna Claims	8/9/2022	8/9/2022	8/10/2022	37,588	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	8/10/2022	8/10/2022	8/11/2022	56,452	0.50	1.00	1.50	0.74%	0.01
Aetna Claims	8/12/2022	8/12/2022	8/15/2022	37,339	0.50	3.00	3.50	0.49%	0.02
Aetna Claims	8/16/2022	8/16/2022	8/17/2022	35,161	0.50	1.00	1.50	0.46%	0.01
Aetna Claims	8/17/2022	8/17/2022	8/18/2022	56,426	0.50	1.00	1.50	0.74%	0.01
Aetna Claims	8/19/2022	8/19/2022	8/22/2022	38,443	0.50	3.00	3.50	0.51%	0.02
Aetna Claims	8/23/2022	8/23/2022	8/24/2022	38,682	0.50	1.00	1.50	0.51%	0.01
Aetna Claims	8/24/2022	8/24/2022	8/25/2022	53,409	0.50	1.00	1.50	0.70%	0.01
Aetna Claims	8/25/2022	8/25/2022	8/26/2022	23,557	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	8/29/2022	8/29/2022	8/30/2022	27,826	0.50	1.00	1.50	0.37%	0.01
Aetna Claims	8/31/2022	8/31/2022	9/1/2022	71,015	0.50	1.00	1.50	0.94%	0.01
Aetna Claims	9/1/2022	9/1/2022	9/2/2022	23,741	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	9/2/2022	9/2/2022	9/6/2022	20,219	0.50	4.00	4.50	0.27%	0.01
Aetna Claims	9/7/2022	9/7/2022	9/8/2022	73,351	0.50	1.00	1.50	0.97%	0.01
Aetna Claims	9/8/2022	9/8/2022	9/9/2022	20,520	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	9/9/2022	9/9/2022	9/12/2022	26,531	0.50	3.00	3.50	0.35%	0.01
Aetna Claims	9/13/2022	9/13/2022	9/14/2022	34,432	0.50	1.00	1.50	0.45%	0.01
Aetna Claims	9/14/2022	9/14/2022	9/15/2022	62,597	0.50	1.00	1.50	0.82%	0.01
Aetna Claims	9/16/2022	9/16/2022	9/19/2022	42,149	0.50	3.00	3.50	0.56%	0.02
Aetna Claims	9/20/2022	9/20/2022	9/21/2022	34,930	0.50	1.00	1.50	0.46%	0.01
Aetna Claims	9/21/2022	9/21/2022	9/22/2022	60,614	0.50	1.00	1.50	0.80%	0.01
Aetna Claims	9/23/2022	9/23/2022	9/26/2022	25,317	0.50	3.00	3.50	0.33%	0.01
Aetna Claims	9/27/2022	9/27/2022	9/28/2022	30,418	0.50	1.00	1.50	0.40%	0.01
Aetna Claims	9/28/2022	9/28/2022	9/29/2022	55,041	0.50	1.00	1.50	0.72%	0.01
Aetna Claims	9/30/2022	9/30/2022	10/3/2022	39,693	0.50	3.00	3.50	0.52%	0.02
Aetna Claims	10/3/2022	10/3/2022	10/4/2022	20,072	0.50	1.00	1.50	0.26%	0.00
Aetna Claims	10/4/2022	10/4/2022	10/5/2022	22,696	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	10/5/2022	10/5/2022	10/6/2022	49,516	0.50	1.00	1.50	0.65%	0.01
Aetna Claims	10/7/2022	10/7/2022	10/11/2022	33,620	0.50	4.00	4.50	0.44%	0.02
Aetna Claims	10/12/2022	10/12/2022	10/13/2022	75,410	0.50	1.00	1.50	0.99%	0.01
Aetna Claims	10/13/2022	10/13/2022	10/14/2022	30,907	0.50	1.00	1.50	0.41%	0.01
Aetna Claims	10/17/2022	10/17/2022	10/18/2022	33,092	0.50	1.00	1.50	0.44%	0.01
Aetna Claims	10/19/2022	10/19/2022	10/20/2022	68,409	0.50	1.00	1.50	0.90%	0.01
Aetna Claims	10/20/2022	10/20/2022	10/21/2022	26,862	0.50	1.00	1.50	0.35%	0.01
Aetna Claims	10/24/2022	10/24/2022	10/25/2022	38,067	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	10/26/2022	10/26/2022	10/27/2022	66,746	0.50	1.00	1.50	0.88%	0.01
Aetna Claims	10/28/2022	10/28/2022	10/31/2022	38,740	0.50	3.00	3.50	0.51%	0.02
Aetna Claims	11/1/2022	11/1/2022	11/2/2022	35,661	0.50	1.00	1.50	0.47%	0.01
Aetna Claims	11/2/2022	11/2/2022	11/3/2022	47,963	0.50	1.00	1.50	0.63%	0.01
Aetna Claims	11/3/2022	11/3/2022	11/4/2022	20,491	0.50	1.00	1.50	0.27%	0.00
Aetna Claims	11/7/2022	11/7/2022	11/8/2022	27,974	0.50	1.00	1.50	0.37%	0.01
Aetna Claims	11/8/2022	11/8/2022	11/9/2022	23,085	0.50	1.00	1.50	0.30%	0.00
Aetna Claims	11/9/2022	11/9/2022	11/10/2022	42,756	0.50	1.00	1.50	0.56%	0.01
Aetna Claims	11/10/2022	11/10/2022	11/14/2022	20,630	0.50	4.00	4.50	0.27%	0.01
Aetna Claims	11/15/2022	11/15/2022	11/16/2022	36,525	0.50	1.00	1.50	0.48%	0.01
Aetna Claims	11/16/2022	11/16/2022	11/17/2022	46,310	0.50	1.00	1.50	0.61%	0.01

Aetna Claims	11/18/2022	11/18/2022	11/21/2022	36,162	0.50	3.00	3.50	0.48%	0.02
Aetna Claims	11/22/2022	11/22/2022	11/23/2022	37,623	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	11/23/2022	11/23/2022	11/25/2022	61,598	0.50	2.00	2.50	0.81%	0.02
Aetna Claims	11/28/2022	11/28/2022	11/29/2022	38,081	0.50	1.00	1.50	0.50%	0.01
Aetna Claims	11/30/2022	11/30/2022	12/1/2022	56,643	0.50	1.00	1.50	0.75%	0.01
Aetna Claims	12/1/2022	12/1/2022	12/2/2022	16,073	0.50	1.00	1.50	0.21%	0.00
Aetna Claims	12/5/2022	12/5/2022	12/6/2022	20,077	0.50	1.00	1.50	0.26%	0.00
Aetna Claims	12/6/2022	12/6/2022	12/7/2022	21,657	0.50	1.00	1.50	0.29%	0.00
Aetna Claims	12/7/2022	12/7/2022	12/8/2022	54,129	0.50	1.00	1.50	0.71%	0.01
Aetna Claims	12/8/2022	12/8/2022	12/9/2022	23,543	0.50	1.00	1.50	0.31%	0.00
Aetna Claims	12/12/2022	12/12/2022	12/13/2022	30,042	0.50	1.00	1.50	0.40%	0.01
Aetna Claims	12/13/2022	12/13/2022	12/14/2022	25,091	0.50	1.00	1.50	0.33%	0.00
Aetna Claims	12/14/2022	12/14/2022	12/15/2022	52,885	0.50	1.00	1.50	0.70%	0.01
Aetna Claims	12/16/2022	12/16/2022	12/19/2022	32,158	0.50	3.00	3.50	0.42%	0.01
Aetna Claims	12/20/2022	12/20/2022	12/21/2022	35,381	0.50	1.00	1.50	0.47%	0.01
Aetna Claims	12/21/2022	12/21/2022	12/22/2022	46,967	0.50	1.00	1.50	0.62%	0.01
Aetna Claims	12/23/2022	12/23/2022	12/27/2022	33,184	0.50	4.00	4.50	0.44%	0.02
Aetna Claims	12/28/2022	12/28/2022	12/29/2022	67,152	0.50	1.00	1.50	0.88%	0.01
Aetna Dental	1/1/2022	1/31/2022	1/31/2022	6,758	15.50	-	15.50	0.09%	0.01
Aetna Dental	2/1/2022	2/28/2022	2/28/2022	6,357	14.00	-	14.00	0.08%	0.01
Aetna Dental	3/1/2022	3/31/2022	3/31/2022	6,372	15.50	-	15.50	0.08%	0.01
Aetna Dental	4/1/2022	4/30/2022	4/29/2022	6,193	15.00	(1.00)	14.00	0.08%	0.01
Aetna Dental	5/1/2022	5/31/2022	5/31/2022	6,193	15.50	-	15.50	0.08%	0.01
Aetna Dental	6/1/2022	6/30/2022	7/1/2022	6,270	15.00	1.00	16.00	0.08%	0.01
Aetna Dental	7/1/2022	7/31/2022	7/28/2022	6,291	15.50	(3.00)	12.50	0.08%	0.01
Aetna Dental	8/1/2022	8/31/2022	9/1/2022	6,294	15.50	1.00	16.50	0.08%	0.01
Aetna Dental	9/1/2022	9/30/2022	9/30/2022	6,394	15.00	-	15.00	0.08%	0.01
Aetna Dental	10/1/2022	10/31/2022	11/1/2022	6,680	15.50	1.00	16.50	0.09%	0.01
Aetna Dental	11/1/2022	11/30/2022	12/1/2022	6,717	15.00	1.00	16.00	0.09%	0.01
Aetna Dental	12/1/2022	12/31/2022	12/29/2022	6,717	15.50	(2.00)	13.50	0.09%	0.01
Aetna Dental	1/1/2022	1/31/2022	1/31/2022	2	15.50	-	15.50	0.00%	0.00
Aetna Dental	2/1/2022	2/28/2022	2/28/2022	15,929	14.00	-	14.00	0.21%	0.03
Aetna Dental	3/1/2022	3/31/2022	3/31/2022	15,689	15.50	-	15.50	0.21%	0.03
Aetna Dental	4/1/2022	4/30/2022	4/29/2022	15,718	15.00	(1.00)	14.00	0.21%	0.03
Aetna Dental	5/1/2022	5/31/2022	5/31/2022	15,670	15.50	-	15.50	0.21%	0.03
Aetna Dental	6/1/2022	6/30/2022	7/1/2022	15,679	15.00	1.00	16.00	0.21%	0.03
Aetna Dental	7/1/2022	7/31/2022	7/28/2022	15,648	15.50	(3.00)	12.50	0.21%	0.03
Aetna Dental	8/1/2022	8/31/2022	9/1/2022	15,681	15.50	1.00	16.50	0.21%	0.03
Aetna Dental	9/1/2022	9/30/2022	9/30/2022	15,559	15.00	-	15.00	0.20%	0.03
Aetna Dental	10/1/2022	10/31/2022	11/1/2022	15,491	15.50	1.00	16.50	0.20%	0.03
Aetna Dental	11/1/2022	11/30/2022	12/1/2022	15,489	15.00	1.00	16.00	0.20%	0.03
Aetna Dental	12/1/2022	12/31/2022	12/29/2022	15,476	15.50	(2.00)	13.50	0.20%	0.03
Aetna Dental	1/1/2022	1/31/2022	1/31/2022	27,747	15.50	-	15.50	0.37%	0.06
Aetna Dental	2/1/2022	2/28/2022	2/28/2022	27,813	14.00	-	14.00	0.37%	0.05
Aetna Dental	3/1/2022	3/31/2022	3/31/2022	26,970	15.50	-	15.50	0.36%	0.06
Aetna Dental	4/1/2022	4/30/2022	4/29/2022	26,780	15.00	(1.00)	14.00	0.35%	0.05
Aetna Dental	5/1/2022	5/31/2022	5/31/2022	26,710	15.50	-	15.50	0.35%	0.05
Aetna Dental	6/1/2022	6/30/2022	7/1/2022	26,605	15.00	1.00	16.00	0.35%	0.06
Aetna Dental	7/1/2022	7/31/2022	7/28/2022	26,339	15.50	(3.00)	12.50	0.35%	0.04
Aetna Dental	8/1/2022	8/31/2022	9/1/2022	26,191	15.50	1.00	16.50	0.34%	0.06
Aetna Dental	9/1/2022	9/30/2022	9/30/2022	25,863	15.00	-	15.00	0.34%	0.05
Aetna Dental	10/1/2022	10/31/2022	11/1/2022	25,852	15.50	1.00	16.50	0.34%	0.06

Aetna Dental	11/1/2022	11/30/2022	12/1/2022	25,658	15.00	1.00	16.00	0.34%	0.05
Aetna Dental	12/1/2022	12/31/2022	12/29/2022	25,670	15.50	(2.00)	13.50	0.34%	0.05
Aetna Dental	1/1/2022	1/31/2022	1/31/2022	493	15.50	-	15.50	0.01%	0.00
Aetna Dental	2/1/2022	2/28/2022	2/28/2022	493	14.00	-	14.00	0.01%	0.00
Aetna Dental	3/1/2022	3/31/2022	3/31/2022	554	15.50	-	15.50	0.01%	0.00
Aetna Dental	4/1/2022	4/30/2022	4/29/2022	554	15.00	(1.00)	14.00	0.01%	0.00
Aetna Dental	5/1/2022	5/31/2022	5/31/2022	554	15.50	-	15.50	0.01%	0.00
Aetna Dental	6/1/2022	6/30/2022	7/1/2022	493	15.00	1.00	16.00	0.01%	0.00
Aetna Dental	7/1/2022	7/31/2022	7/28/2022	523	15.50	(3.00)	12.50	0.01%	0.00
Aetna Dental	8/1/2022	8/31/2022	9/1/2022	523	15.50	1.00	16.50	0.01%	0.00
Aetna Dental	9/1/2022	9/30/2022	9/30/2022	585	15.00	-	15.00	0.01%	0.00
Aetna Dental	10/1/2022	10/31/2022	11/1/2022	677	15.50	1.00	16.50	0.01%	0.00
Aetna Dental	11/1/2022	11/30/2022	12/1/2022	616	15.00	1.00	16.00	0.01%	0.00
Aetna Dental	12/1/2022	12/31/2022	12/29/2022	616	15.50	(2.00)	13.50	0.01%	0.00
				$ 7,592,348					2.94

Pension Plan	Service Start Date	Service End Date	Payment Date	Payment Amount	Service Lead Time	Processing Lead Time	Total Unweighted Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Pension	1/1/2022	1/31/2022	1/31/2022	$ 205,070	15.00	-	15.00	8.0%	1.20
Pension	2/1/2022	2/28/2022	2/28/2022	211,529	14.00	-	14.00	8.3%	1.16
Pension	3/1/2022	3/31/2022	3/31/2022	273,100	15.50	-	15.50	10.7%	1.66
Pension	4/1/2022	4/30/2022	4/30/2022	208,135	15.00	-	15.00	8.1%	1.22
Pension	5/1/2022	5/31/2022	5/31/2022	211,176	15.50	-	15.50	8.3%	1.28
Pension	6/1/2022	6/30/2022	6/30/2022	204,274	15.00	-	15.00	8.0%	1.20
Pension	7/1/2022	7/31/2022	7/31/2022	208,439	15.50	-	15.50	8.2%	1.26
Pension	8/1/2022	8/31/2022	8/31/2022	210,929	15.50	-	15.50	8.2%	1.28
Pension	9/1/2022	9/30/2022	9/30/2022	207,421	15.00	-	15.00	8.1%	1.22
Pension	10/1/2022	10/31/2022	10/31/2022	203,816	15.50	-	15.50	8.0%	1.24
Pension	11/1/2022	11/30/2022	11/30/2022	206,925	15.00	-	15.00	8.1%	1.21
Pension	12/1/2022	12/31/2022	12/31/2022	206,473	15.50	-	15.50	8.1%	1.25
				$ 2,557,287.59					15.17

Medical	Service Start Date	Service End Date	Payment Date	Payment Amount	Service Lead Time	Processing Lead Time	Total Unweighted Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Medco Medical	12/11/21	12/24/21	01/05/22	$ 1,730,705	7.00	12.00	19.00	0.75%	0.14
Medco Medical	12/25/21	01/07/22	01/19/22	1,909,376	7.00	12.00	19.00	0.83%	0.16
Medco Medical	01/08/22	01/21/22	01/28/22	2,016,397	7.00	7.00	14.00	0.87%	0.12
Medco Medical	01/22/22	02/04/22	02/10/22	1,957,268	7.00	6.00	13.00	0.85%	0.11
Medco Medical	02/05/22	02/18/22	02/24/22	2,030,258	7.00	6.00	13.00	0.88%	0.11
Medco Medical	02/19/22	03/04/22	03/10/22	2,103,174	7.00	6.00	13.00	0.91%	0.12
Medco Medical	03/05/22	03/18/22	03/24/22	1,753,634	7.00	6.00	13.00	0.76%	0.10
Medco Medical	03/19/22	04/01/22	04/08/22	2,172,904	7.00	7.00	14.00	0.94%	0.13
Medco Medical	04/02/22	04/15/22	04/27/22	1,686,180	7.00	12.00	19.00	0.73%	0.14
Medco Medical	04/16/22	04/29/22	05/11/22	2,053,930	7.00	12.00	19.00	0.89%	0.17
Medco Medical	04/30/22	05/13/22	05/19/22	1,968,576	7.00	6.00	13.00	0.85%	0.11
Medco Medical	05/14/22	05/27/22	06/01/22	2,036,546	7.00	5.00	12.00	0.88%	0.11

Medco Medical	05/28/22	06/10/22	06/16/22	2,042,296	7.00	6.00	13.00	0.88%	0.11
Medco Medical	05/28/22	06/10/22	06/16/22	45	7.00	6.00	13.00	0.00%	0.00
Medco Medical	06/11/22	06/24/22	06/30/22	2,029,582	7.00	6.00	13.00	0.88%	0.11
Medco Medical	06/25/22	07/08/22	07/14/22	1,801,942	7.00	6.00	13.00	0.78%	0.10
Medco Medical	07/09/22	07/22/22	07/28/22	2,019,472	7.00	6.00	13.00	0.87%	0.11
Medco Medical	07/23/22	08/05/22	08/15/22	2,186,357	7.00	10.00	17.00	0.95%	0.16
Medco Medical	08/06/22	08/19/22	08/25/22	2,097,718	7.00	6.00	13.00	0.91%	0.12
Medco Medical	08/20/22	09/02/22	09/08/22	2,151,595	7.00	6.00	13.00	0.93%	0.12
Medco Medical	09/03/22	09/16/22	09/22/22	2,100,828	7.00	6.00	13.00	0.91%	0.12
Medco Medical	09/17/22	09/30/22	10/06/22	1,774,679	7.00	6.00	13.00	0.77%	0.10
Medco Medical	10/01/22	10/14/22	10/20/22	2,145,210	7.00	6.00	13.00	0.93%	0.12
Medco Medical	10/15/22	10/28/22	11/03/22	2,098,675	7.00	6.00	13.00	0.91%	0.12
Medco Medical	10/29/22	11/11/22	11/17/22	2,224,105	7.00	6.00	13.00	0.96%	0.13
Medco Medical	11/12/22	11/25/22	11/30/22	2,142,496	7.00	5.00	12.00	0.93%	0.11
Medco Medical	11/26/22	12/09/22	12/16/22	2,238,418	7.00	7.00	14.00	0.97%	0.14
Medco Medical	12/10/22	12/23/22	12/29/22	2,159,373	7.00	6.00	13.00	0.93%	0.12
Horizon Admin	01/01/22	01/31/22	01/31/22	278,013	15.50	-	15.50	0.12%	0.02
Horizon Admin	02/01/22	02/28/22	02/28/22	278,699	14.00	-	14.00	0.12%	0.02
Horizon Admin	03/01/22	03/31/22	03/31/22	272,231	15.50	-	15.50	0.12%	0.02
Horizon Admin	04/01/22	04/30/22	04/29/22	273,865	15.00	(1.00)	14.00	0.12%	0.02
Horizon Admin	05/01/22	05/31/22	05/31/22	274,322	15.50	-	15.50	0.12%	0.02
Horizon Admin	06/01/22	06/30/22	07/01/22	274,578	15.00	1.00	16.00	0.12%	0.02
Horizon Admin	07/01/22	07/31/22	07/28/22	274,938	15.50	(3.00)	12.50	0.12%	0.01
Horizon Admin	08/01/22	08/31/22	09/01/22	274,482	15.50	1.00	16.50	0.12%	0.02
Horizon Admin	09/01/22	09/30/22	09/30/22	274,636	15.00	-	15.00	0.12%	0.02
Horizon Admin	10/01/22	10/31/22	11/01/22	273,143	15.50	1.00	16.50	0.12%	0.02
Horizon Admin	11/01/22	11/30/22	12/01/22	273,529	15.00	1.00	16.00	0.12%	0.02
Horizon Admin	12/01/22	12/31/22	12/29/22	273,481	15.50	(2.00)	13.50	0.12%	0.02
Horizon Medical	12/27/21	12/31/21	01/20/22	3,269,044	2.50	20.00	22.50	1.41%	0.32
Horizon Medical	12/20/21	12/26/21	01/03/22	2,714,179	3.50	8.00	11.50	1.17%	0.14
Horizon Medical	01/01/22	01/02/22	01/10/22	433,479	1.00	8.00	9.00	0.19%	0.02
Horizon Medical	01/03/22	01/09/22	01/18/22	3,471,082	3.50	9.00	12.50	1.50%	0.19
Horizon Medical	01/10/22	01/16/22	01/27/22	2,380,443	3.50	11.00	14.50	1.03%	0.15
Horizon Medical	01/17/22	01/23/22	01/31/22	2,733,595	3.50	8.00	11.50	1.18%	0.14
Horizon Medical	01/24/22	01/30/22	02/08/22	4,638,419	3.50	9.00	12.50	2.01%	0.25
Horizon Medical	01/31/22	01/31/22	02/22/22	487,713	0.50	22.00	22.50	0.21%	0.05
Horizon Medical	02/01/22	02/06/22	02/11/22	3,299,081	3.00	5.00	8.00	1.43%	0.11
Horizon Medical	02/07/22	02/13/22	02/18/22	3,305,351	3.50	5.00	8.50	1.43%	0.12
Horizon Medical	02/14/22	02/20/22	02/28/22	2,474,418	3.50	8.00	11.50	1.07%	0.12
Horizon Medical	02/21/22	02/27/22	03/04/22	2,705,428	3.50	5.00	8.50	1.17%	0.10
Horizon Medical	02/28/22	02/28/22	03/28/22	382,755	0.50	28.00	28.50	0.17%	0.05
Horizon Medical	03/01/22	03/06/22	03/15/22	3,154,120	3.00	9.00	12.00	1.36%	0.16
Horizon Medical	03/07/22	03/13/22	03/18/22	3,074,441	3.50	5.00	8.50	1.33%	0.11
Horizon Medical	03/14/22	03/20/22	03/25/22	3,520,866	3.50	5.00	8.50	1.52%	0.13
Horizon Medical	03/21/22	03/27/22	04/01/22	3,226,476	3.50	5.00	8.50	1.40%	0.12
Horizon Medical	03/28/22	03/31/22	04/20/22	2,250,306	2.00	20.00	22.00	0.97%	0.21
Horizon Medical	04/01/22	04/03/22	04/11/22	1,171,712	1.50	8.00	9.50	0.51%	0.05
Horizon Medical	04/04/22	04/10/22	04/18/22	3,670,717	3.50	8.00	11.50	1.59%	0.18
Horizon Medical	04/11/22	04/17/22	04/25/22	3,284,675	3.50	8.00	11.50	1.42%	0.16
Horizon Medical	04/18/22	04/24/22	04/29/22	2,799,105	3.50	5.00	8.50	1.21%	0.10
Horizon Medical	04/25/22	04/30/22	05/18/22	3,391,888	3.00	18.00	21.00	1.47%	0.31
Horizon Medical	05/02/22	05/08/22	05/16/22	3,053,534	3.50	8.00	11.50	1.32%	0.15

Horizon Medical	05/09/22	05/15/22	05/23/22	4,342,774	3.50	8.00	11.50	1.88%	0.22
Horizon Medical	05/16/22	05/22/22	05/27/22	3,260,888	3.50	5.00	8.50	1.41%	0.12
Horizon Medical	05/23/22	05/29/22	06/03/22	3,198,329	3.50	5.00	8.50	1.38%	0.12
Horizon Medical	05/30/22	05/31/22	07/01/22	891,182	1.00	31.00	32.00	0.39%	0.12
Horizon Medical	06/01/22	06/05/22	06/16/22	1,980,125	2.50	11.00	13.50	0.86%	0.12
Horizon Medical	06/06/22	06/12/22	06/21/22	3,129,182	3.50	9.00	12.50	1.35%	0.17
Horizon Medical	06/13/22	06/19/22	06/27/22	3,894,423	3.50	8.00	11.50	1.68%	0.19
Horizon Medical	06/20/22	06/26/22	07/01/22	3,261,431	3.50	5.00	8.50	1.41%	0.12
Horizon Medical	06/27/22	06/30/22	07/21/22	2,004,345	2.00	21.00	23.00	0.87%	0.20
Horizon Medical	07/01/22	07/03/22	07/08/22	994,465	1.50	5.00	6.50	0.43%	0.03
Horizon Medical	07/04/22	07/10/22	07/18/22	3,541,957	3.50	8.00	11.50	1.53%	0.18
Horizon Medical	07/11/22	07/17/22	07/22/22	2,996,009	3.50	5.00	8.50	1.30%	0.11
Horizon Medical	07/18/22	07/24/22	08/01/22	2,875,888	3.50	8.00	11.50	1.24%	0.14
Horizon Medical	07/25/22	07/31/22	08/23/22	3,379,504	3.50	23.00	26.50	1.46%	0.39
Horizon Medical	08/01/22	08/07/22	08/16/22	3,085,565	3.50	9.00	12.50	1.33%	0.17
Horizon Medical	08/08/22	08/14/22	08/24/22	3,427,021	3.50	10.00	13.50	1.48%	0.20
Horizon Medical	08/15/22	08/21/22	08/26/22	2,907,889	3.50	5.00	8.50	1.26%	0.11
Horizon Medical	08/22/22	08/28/22	09/02/22	2,848,521	3.50	5.00	8.50	1.23%	0.10
Horizon Medical	08/29/22	08/31/22	09/26/22	1,732,143	1.50	26.00	27.50	0.75%	0.21
Horizon Medical	09/01/22	09/04/22	09/12/22	1,625,696	2.00	8.00	10.00	0.70%	0.07
Horizon Medical	09/05/22	09/11/22	09/19/22	2,271,908	3.50	8.00	11.50	0.98%	0.11
Horizon Medical	09/12/22	09/18/22	09/26/22	3,945,315	3.50	8.00	11.50	1.71%	0.20
Horizon Medical	09/19/22	09/25/22	10/11/22	3,469,404	3.50	16.00	19.50	1.50%	0.29
Horizon Medical	09/26/22	09/30/22	11/01/22	2,922,030	2.50	32.00	34.50	1.26%	0.44
Horizon Medical	10/03/22	10/09/22	10/14/22	3,991,537	3.50	5.00	8.50	1.73%	0.15
Horizon Medical	10/10/22	10/16/22	10/21/22	3,136,001	3.50	5.00	8.50	1.36%	0.12
Horizon Medical	10/17/22	10/23/22	10/28/22	2,747,049	3.50	5.00	8.50	1.19%	0.10
Horizon Medical	10/24/22	10/30/22	11/04/22	3,286,449	3.50	5.00	8.50	1.42%	0.12
Horizon Medical	10/31/22	10/31/22	12/07/22	212,364	0.50	37.00	37.50	0.09%	0.03
Horizon Medical	11/01/22	11/06/22	11/14/22	3,295,402	3.00	8.00	11.00	1.43%	0.16
Horizon Medical	11/07/22	11/13/22	11/18/22	3,444,113	3.50	5.00	8.50	1.49%	0.13
Horizon Medical	11/14/22	11/20/22	11/30/22	3,548,789	3.50	10.00	13.50	1.54%	0.21
Horizon Medical	11/21/22	11/27/22	12/02/22	2,975,178	3.50	5.00	8.50	1.29%	0.11
Horizon Medical	11/28/22	11/30/22	12/22/22	1,376,845	1.50	22.00	23.50	0.60%	0.14
Horizon Medical	12/01/22	12/04/22	12/13/22	1,867,767	2.00	9.00	11.00	0.81%	0.09
Horizon Medical	12/05/22	12/11/22	12/19/22	3,348,458	3.50	8.00	11.50	1.45%	0.17
Horizon Medical	12/12/22	12/18/22	12/23/22	3,377,138	3.50	5.00	8.50	1.46%	0.12
Horizon Medical	12/19/22	12/25/22	12/30/22	3,770,103	3.50	5.00	8.50	1.63%	0.14
				$ 231,183,665					12.86

Group Life Insurance (A)	Service Start Date (B)	Service End Date (C)	Payment Date (D)	Payment Amount (E)	Service Lead Time (F)	Processing Lead Time (G)	Total Unweighted Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
Group Life insurance	01/01/22	01/31/22	01/31/22	$ 1,064,101	15.50	-	15.50	9.21%	1.43
Group Life insurance	02/01/22	02/28/22	02/28/22	1,043,554	14.00	-	14.00	9.03%	1.26
Group Life insurance	03/01/22	03/31/22	03/31/22	1,048,084	15.50	-	15.50	9.07%	1.41
Group Life insurance	04/01/22	04/30/22	04/29/22	915,709	15.00	(1.00)	14.00	7.92%	1.11
Group Life insurance	05/01/22	05/31/22	05/31/22	977,016	15.50	-	15.50	8.45%	1.31
Group Life insurance	06/01/22	06/30/22	07/01/22	974,485	15.00	1.00	16.00	8.43%	1.35
Group Life insurance	07/01/22	07/31/22	07/28/22	965,068	15.50	(3.00)	12.50	8.35%	1.04
Group Life insurance	08/01/22	08/31/22	09/01/22	802,111	15.50	1.00	16.50	6.94%	1.15
Group Life insurance	09/01/22	09/30/22	09/30/22	932,885	15.00	-	15.00	8.07%	1.21
Group Life insurance	10/01/22	10/31/22	11/01/22	951,316	15.50	1.00	16.50	8.23%	1.36
Group Life insurance	11/01/22	11/30/22	12/01/22	948,272	15.00	1.00	16.00	8.21%	1.31
Group Life insurance	12/01/22	12/31/22	12/29/22	933,927	15.50	(2.00)	13.50	8.08%	1.09
				$ 11,556,529					15.03

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
OTHER OPERATION AND MAINTENANCE

Lead Tir 36.10 days

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	5100007446	Borough of Bellmawr	1/31/2022	2/10/2022	$ 578		Service				15.21	10.00		25.21	0.01%	0.003
2	5100063286	HILLSBOROUGH TWP. POLICE DEPT.	10/8/2022	10/26/2022	392		Service				15.21	18.00		33.21	0.01%	0.003
3	5200051013	WESCO DISTRIBUTION, INC	8/12/2022	8/19/2022	244		Service				15.21	7.00		22.21	0.01%	0.001
4	5200080977	ROMAN E&G CORP	12/14/2022	12/28/2022	719		Service				15.21	14.00		29.21	0.02%	0.005
5	5100055389	SUBURBAN CONSULTING ENGINEERS, INC.	9/16/2022	10/14/2022	625	Check	Service				15.21	28.00	12.23	55.44	0.01%	0.008
6	5100016624	TRU-VAL ELECTRICAL CORPORATION	3/16/2022	4/14/2022	393		Service				15.21	29.00		44.21	0.01%	0.004
7	5200061422	REPAIRCLINIC LLC	9/23/2022	10/21/2022	170		Service				15.21	28.00		43.21	0.00%	0.002
8	5100044622	ADVANCED TRAFFIC CONTROL, LLC	3/3/2022	8/2/2022	585		Service				15.21	152.00		167.21	0.01%	0.022
9	5100006540	APPROVED FIRE PROTECTION CO., INC	6/24/2021	2/1/2022	540		Service				15.21	222.00		237.21	0.01%	0.028
10	5100024794	HAMPTON-CLARKE INC	4/29/2022	5/27/2022	867	Check	Service				15.21	28.00	12.23	55.44	0.02%	0.011
11	5200055317	ROMAN E&G CORP	8/31/2022	9/1/2022	719		Service				15.21	1.00		16.21	0.02%	0.003
12	5200017099	WESCO DISTRIBUTION, INC	3/23/2022	4/1/2022	378		Service				15.21	9.00		24.21	0.01%	0.002
13	5200039478	WESCO DISTRIBUTION, INC	6/22/2022	7/1/2022	381		Service				15.21	9.00		24.21	0.01%	0.002
14	5200032901	REPAIRCLINIC LLC	5/23/2022	6/22/2022	252		Service				15.21	30.00		45.21	0.01%	0.003
15	5200001888	WATERS & BUGBEE, INC.	1/13/2022	2/2/2022	195		Service				15.21	20.00		35.21	0.00%	0.002
16	5100040356	K. MOOREA CO LLC	6/27/2022	7/18/2022	726		Service				15.21	21.00		36.21	0.02%	0.006
17	5200006016	WESCO DISTRIBUTION, INC	1/31/2022	2/7/2022	694		Service				15.21	7.00		22.21	0.02%	0.003
18	5200058374	LANTIER CONSTRUCTION COMPANY INC	9/13/2022	9/30/2022	731		Service				15.21	17.00		32.21	0.02%	0.005
19	5100010498	JOSEPH V. CAPOZZI, INC.	2/22/2022	3/24/2022	588		Service				15.21	30.00		45.21	0.01%	0.006
20	5100071930	PARS ENVIRONMENTAL SERVICES	11/15/2022	12/15/2022	163		Service				15.21	30.00		45.21	0.00%	0.002
21	5200061039	JOSEPH M SANZARI INC	9/23/2022	10/7/2022	825		Service				15.21	14.00		29.21	0.02%	0.005
22	5200025508	WESCO DISTRIBUTION, INC	4/25/2022	5/2/2022	825		Service				15.21	7.00		22.21	0.02%	0.004
23	5200014239	WESCO DISTRIBUTION, INC	3/8/2022	3/17/2022	426		Service				15.21	9.00		24.21	0.01%	0.002
24	5100042394	STEWART & STEVENSON POWER	6/2/2022	8/2/2022	937		Service				15.21	61.00		76.21	0.02%	0.016
25	5200012510	WESCO DISTRIBUTION, INC	2/28/2022	3/7/2022	338		Service				15.21	7.00		22.21	0.01%	0.002
26	5100048056	BAYSHORE RECYCLING CORP	8/19/2022	9/16/2022	559		Service				15.21	28.00		43.21	0.01%	0.005
27	5200053339	WESCO DISTRIBUTION, INC	8/24/2022	9/2/2022	156		Service				15.21	9.00		24.21	0.00%	0.001
28	5200053646	NOCAR CONTRACTORS	8/25/2022	9/16/2022	750		Service				15.21	22.00		37.21	0.02%	0.006
29	5100016437	BERGEN COUNTY SHERIFFS OFFICE	3/23/2022	4/1/2022	500		Service				15.21	9.00		24.21	0.01%	0.003
30	5200032464	JOSEPH M SANZARI INC	5/23/2022	5/24/2022	825		Service				15.21	1.00		16.21	0.02%	0.003
31	5200076177	PONTOON SOLUTIONS, INC.	11/24/2022	11/29/2022	215		Service				15.21	5.00		20.21	0.00%	0.001
32	5100057862	CLEAN HARBORS ENVIRONMENTAL SVCS CO	10/10/2022	11/9/2022	362		Service				15.21	30.00		45.21	0.01%	0.004
33	5200014314	WATERS & BUGBEE, INC.	3/8/2022	3/18/2022	675		Service				15.21	10.00		25.21	0.01%	0.004
34	5200059985	WESCO DISTRIBUTION, INC	9/19/2022	9/26/2022	796		Service				15.21	7.00		22.21	0.02%	0.004
35	5200006981	WESCO DISTRIBUTION, INC	2/2/2022	2/11/2022	658		Service				15.21	9.00		24.21	0.01%	0.004
36	5100017605	AC MILLER CONCRETE PRODUCTS	2/26/2022	3/29/2022	410		Service				15.21	31.00		46.21	0.01%	0.004
37	5200024370	SIGNIFY NORTH AMERICA CORPORATION	4/20/2022	5/19/2022	699		Service				15.21	29.00		44.21	0.02%	0.007
38	5100061631	ASSOCIATED FIRE PROTECTION	10/4/2022	11/3/2022	390		Service				15.21	30.00		45.21	0.01%	0.004
39	5100042328	ECOLSCIENCES	7/11/2022	7/26/2022	110		Service				15.21	15.00		30.21	0.00%	0.001
40	5100060295	BOROUGH OF ALPINE	9/12/2022	10/17/2022	614		Service				15.21	35.00		50.21	0.01%	0.007
41	5200021277	WESCO DISTRIBUTION, INC	4/4/2022	4/11/2022	146		Service				15.21	7.00		22.21	0.00%	0.001
42	5200027103	Atlantic InfraRed, Inc	4/29/2022	5/2/2022	888		Service				15.21	3.00		18.21	0.02%	0.004
43	5100023121	BAYSHORE RECYCLING CORP	4/13/2022	5/13/2022	730		Service				15.21	30.00		45.21	0.02%	0.007
44	5200008015	WESCO DISTRIBUTION, INC	2/8/2022	2/17/2022	355		Service				15.21	9.00		24.21	0.01%	0.002
45	5200047834	Atlantic InfraRed, Inc	7/27/2022	7/28/2022	415		Service				15.21	1.00		16.21	0.01%	0.001
46	5100052322	MOUNT CONSTRUCTION CO INC	8/17/2022	9/16/2022	549		Service				15.21	30.00		45.21	0.01%	0.005
47	5200020083	WESCO DISTRIBUTION, INC	3/31/2022	4/8/2022	815		Service				15.21	8.00		23.21	0.02%	0.004
48	5200044719	WESCO DISTRIBUTION, INC	7/14/2022	7/15/2022	295		Service				15.21	1.00		16.21	0.01%	0.001
49	5200050857	WESCO DISTRIBUTION, INC	8/11/2022	8/19/2022	203		Service				15.21	8.00		23.21	0.00%	0.001
50	5200055268	ROMAN E&G CORP	8/31/2022	9/1/2022	611		Service				15.21	1.00		16.21	0.01%	0.002
51	5200035273	CHARLES F CONNOLLY DIST CO INC	6/3/2022	7/1/2022	801		Service				15.21	28.00		43.21	0.02%	0.008
52	5200009743	HENKELS & MCCOY, INC.	2/17/2022	2/17/2022	896		Service				15.21	-		15.21	0.02%	0.003
53	5200031039	E H ALLEN & SON INC	5/17/2022	6/15/2022	650		Service				15.21	29.00		44.21	0.01%	0.006

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
54	5100022659	IMWOTH LLC	3/31/2022	4/29/2022	110		Service				15.21	29.00		44.21	0.00%	0.001
55	5200081723	WESCO DISTRIBUTION, INC	12/16/2022	12/23/2022	570		Service				15.21	7.00		22.21	0.01%	0.003
56	5200072705	WESCO DISTRIBUTION, INC	11/11/2022	11/18/2022	108		Service				15.21	7.00		22.21	0.00%	0.001
57	5200021555	WESCO DISTRIBUTION, INC	4/5/2022	4/14/2022	233		Service				15.21	9.00		24.21	0.01%	0.001
58	5200013049	JOHNSTONE SUPPLY	3/1/2022	3/30/2022	870		Service				15.21	29.00		44.21	0.02%	0.008
59	5200029696	WESCO DISTRIBUTION, INC	5/11/2022	5/20/2022	200		Service				15.21	9.00		24.21	0.00%	0.001
60	5200072377	WESCO DISTRIBUTION, INC	11/10/2022	11/18/2022	200		Service				15.21	8.00		23.21	0.00%	0.001
61	5100069387	UNITED RENTALS (NORTH AMERICA) INC	9/19/2022	11/21/2022	714		Service				15.21	63.00		78.21	0.02%	0.012
62	5200054167	WESCO DISTRIBUTION, INC	8/26/2022	9/2/2022	199		Service				15.21	7.00		22.21	0.00%	0.001
63	5200053613	WESCO DISTRIBUTION, INC	8/25/2022	9/2/2022	118		Service				15.21	8.00		23.21	0.00%	0.001
64	5100062697	TOWNSHIP OF WEST CALDWELL	9/13/2022	10/26/2022	855		Service				15.21	43.00		58.21	0.02%	0.011
65	5200070455	WESCO DISTRIBUTION, INC	11/2/2022	11/10/2022	477		Service				15.21	8.00		23.21	0.01%	0.002
66	5200007009	REPAIRCLINIC LLC	2/25/2022	3/25/2022	535		Service				15.21	28.00		43.21	0.01%	0.005
67	5100035222	AC MILLER CONCRETE PRODUCTS	6/2/2022	7/6/2022	908		Service				15.21	34.00		49.21	0.02%	0.010
68	5100026194	BINGHAM & TAYLOR	4/11/2022	5/18/2022	128		Service				15.21	37.00		52.21	0.00%	0.001
69	5200058399	JOSEPH M SANZARI INC	9/13/2022	9/30/2022	776		Service				15.21	17.00		32.21	0.02%	0.006
70	5200067062	WESCO DISTRIBUTION, INC	10/19/2022	10/28/2022	292		Service				15.21	9.00		24.21	0.01%	0.002
71	5200056995	WESCO DISTRIBUTION, INC	9/5/2022	9/12/2022	332		Service				15.21	7.00		22.21	0.01%	0.002
72	5200082781	Atlantic InfraRed, Inc	12/21/2022	1/19/2023	450		Service				15.21	29.00		44.21	0.01%	0.004
73	5200044424	WESCO DISTRIBUTION, INC	7/13/2022	7/22/2022	218		Service				15.21	9.00		24.21	0.00%	0.001
74	5200051256	LANTIER CONSTRUCTION COMPANY INC	8/15/2022	9/2/2022	650		Service				15.21	18.00		33.21	0.01%	0.005
75	5100047178	PARS ENVIRONMENTAL SERVICES	8/15/2022	9/14/2022	365		Service				15.21	30.00		45.21	0.01%	0.004
76	5100011429	WILLIAM J GUARINI INC.	2/22/2022	3/24/2022	719		Service				15.21	30.00		45.21	0.02%	0.007
77	5200005152	NOCAR CONTRACTORS	1/28/2022	2/17/2022	797		Service				15.21	20.00		35.21	0.02%	0.006
78	5200005401	REPAIRCLINIC LLC	1/30/2022	3/1/2022	751		Service				15.21	30.00		45.21	0.02%	0.007
79	5200009145	MILLER PIPELINE CORP	2/16/2022	3/17/2022	384		Service				15.21	29.00		44.21	0.01%	0.004
80	5200068778	WESCO DISTRIBUTION, INC	10/27/2022	11/4/2022	124		Service				15.21	8.00		23.21	0.00%	0.001
81	5200063755	LANTIER CONSTRUCTION COMPANY INC	10/3/2022	10/14/2022	893		Service				15.21	11.00		26.21	0.02%	0.005
82	5100058463	BAYSHORE RECYCLING CORP	9/20/2022	10/20/2022	300		Service				15.21	30.00		45.21	0.01%	0.003
83	5200006526	KEMSCO CONSTRUCTION & EQUIP CO INC	2/1/2022	2/4/2022	416		Service				15.21	3.00		18.21	0.01%	0.002
84	5200013580	WESCO DISTRIBUTION, INC	3/3/2022	3/11/2022	228		Service				15.21	8.00		23.21	0.01%	0.001
85	5200048578	HENKELS & MCCOY, INC.	7/29/2022	8/12/2022	712		Service				15.21	14.00		29.21	0.02%	0.005
86	5100012385	BAYSHORE RECYCLING CORP	2/24/2022	3/25/2022	285		Service				15.21	29.00		44.21	0.01%	0.003
87	5200004503	NOCAR CONTRACTORS	1/25/2022	2/4/2022	750		Service				15.21	10.00		25.21	0.02%	0.004
88	5200077492	LANTIER CONSTRUCTION COMPANY INC	11/30/2022	12/1/2022	650		Service				15.21	1.00		16.21	0.01%	0.002
89	5200001318	M. T. DEASON COMPANY, INC.	1/10/2022	8/16/2022	273		Service				15.21	218.00		233.21	0.01%	0.014
90	5200050011	WESCO DISTRIBUTION, INC	8/5/2022	8/12/2022	218		Service				15.21	7.00		22.21	0.00%	0.001
91	5200079866	JOHNSTONE SUPPLY	12/8/2022	1/6/2023	102		Service				15.21	29.00		44.21	0.00%	0.001
92	5100053682	WESCO DISTRIBUTION, INC	9/12/2022	9/22/2022	272		Service				15.21	10.00		25.21	0.01%	0.002
93	5200083088	KEMSCO CONSTRUCTION & EQUIP CO INC	12/22/2022	12/23/2022	832		Service				15.21	1.00		16.21	0.02%	0.003
94	5200046638	NOCAR CONTRACTORS	7/22/2022	8/4/2022	891		Service				15.21	13.00		28.21	0.02%	0.006
95	5100068415	CHEMTECH CONSULTING GROUP, INC.	10/26/2022	11/23/2022	572		Service				15.21	28.00		43.21	0.01%	0.005
96	5100072764	CHEMTECH CONSULTING GROUP, INC.	11/21/2022	12/21/2022	957		Service				15.21	30.00		45.21	0.02%	0.010
97	5200055980	WESCO DISTRIBUTION, INC	9/1/2022	9/9/2022	548		Service				15.21	8.00		23.21	0.01%	0.003
98	5100071603	MOUNT CONSTRUCTION CO INC	11/10/2022	12/9/2022	947		Service				15.21	29.00		44.21	0.02%	0.009
99	5100073139	WASTE MANAGEMENT OF NEW JERSEY INC	11/15/2022	12/15/2022	841		Service				15.21	30.00		45.21	0.02%	0.008
100	5200027206	ROMAN E&G CORP	4/29/2022	5/18/2022	719		Service				15.21	19.00		34.21	0.02%	0.005
101	5200010638	WESCO DISTRIBUTION, INC	2/21/2022	2/28/2022	863		Service				15.21	7.00		22.21	0.02%	0.004
102	5100001610	BAYSHORE RECYCLING CORP	1/4/2022	2/2/2022	256		Service				15.21	29.00		44.21	0.01%	0.002
103	5100069533	PSC INDUSTRIAL OUTSOURCING, LP	11/9/2022	12/9/2022	744		Service				15.21	30.00		45.21	0.02%	0.007
104	5100009407	VEHICLE TRACKING SOLUTIONS, LLC	2/11/2022	3/11/2022	125		Service				15.21	28.00		43.21	0.00%	0.001
105	5100026784	JOSEPH V. CAPOZZI, INC.	4/26/2022	5/26/2022	718		Service				15.21	30.00		45.21	0.02%	0.007
106	5200067252	WESCO DISTRIBUTION, INC	10/20/2022	10/28/2022	127		Service				15.21	8.00		23.21	0.00%	0.001
107	5200020637	MARCONE APPLIANCE PARTS COMPANY	4/1/2022	4/29/2022	108		Service				15.21	28.00		43.21	0.00%	0.001
108	5100025032	AIRGAS USA, LLC	3/31/2022	4/29/2022	810		Service				15.21	29.00		44.21	0.02%	0.008
109	5100070912	LIBERTY SALES AND DISTRIBUTION, LLC	8/31/2022	11/22/2022	320		Service				15.21	83.00		98.21	0.01%	0.007
110	5200006509	KEMSCO CONSTRUCTION & EQUIP CO INC	2/1/2022	2/4/2022	468		Service				15.21	3.00		18.21	0.01%	0.002
111	5100071227	COUNTY OF SOMERSET	11/4/2022	12/2/2022	959	Check	Service				15.21	28.00	12.23	55.44	0.02%	0.012

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
112	5200036062	MARCONE APPLIANCE PARTS COMPANY	6/7/2022	7/6/2022	119		Service				15.21	29.00		44.21	0.00%	0.001
113	5100021048	ASSOCIATED FIRE PROTECTION	3/29/2022	4/28/2022	325		Service				15.21	30.00		45.21	0.01%	0.003
114	5200030663	M. T. DEASON COMPANY, INC.	5/16/2022	7/6/2022	938	Check	Service				15.21	51.00	12.23	78.44	0.02%	0.016
115	5200018260	WESCO DISTRIBUTION, INC	3/28/2022	4/5/2022	320		Service				15.21	8.00		23.21	0.01%	0.002
116	5200013660	MARCONE APPLIANCE PARTS COMPANY	3/4/2022	4/1/2022	135		Service				15.21	28.00		43.21	0.00%	0.001
117	5100006560	JAN X-Ray Services, Inc.	1/18/2022	2/17/2022	606		Service				15.21	30.00		45.21	0.01%	0.006
118	5100000789	MATRIX NEW WORLD ENGINEERING, INC	1/14/2022	2/11/2022	223		Service				15.21	28.00		43.21	0.00%	0.002
119	5100027093	PARS ENVIRONMENTAL SERVICES	5/19/2022	6/17/2022	744		Service				15.21	29.00		44.21	0.02%	0.007
120	5200068353	PARS ENVIRONMENTAL SERVICES	10/26/2022	10/27/2022	995		Service				15.21	1.00		16.21	0.02%	0.004
121	5100008017	CLEAN HARBORS ENVIRONMENTAL SVCS CO	2/4/2022	3/4/2022	580		Service				15.21	28.00		43.21	0.01%	0.006
122	5200085358	WESCO DISTRIBUTION, INC	12/30/2022	1/6/2023	441		Service				15.21	7.00		22.21	0.01%	0.002
123	5100034773	TRU-VAL ELECTRICAL CORPORATION	6/16/2022	7/15/2022	305		Service				15.21	29.00		44.21	0.01%	0.003
124	5100019200	ENERGY ONE ELECTRONICS, INC.	2/11/2022	4/4/2022	114		Service				15.21	52.00		67.21	0.00%	0.002
125	5200000186	WESCO DISTRIBUTION, INC	1/4/2022	1/13/2022	569		Service				15.21	9.00		24.21	0.01%	0.003
126	5200022891	JOSEPH M SANZARI INC	4/14/2022	4/28/2022	970		Service				15.21	14.00		29.21	0.02%	0.006
127	5100047564	BAYSHORE RECYCLING CORP	8/16/2022	9/15/2022	395		Service				15.21	30.00		45.21	0.01%	0.004
128	5100067835	HERITAGE-CRYSTAL CLEAN, LLC	10/25/2022	11/23/2022	228		Service				15.21	29.00		44.21	0.01%	0.002
129	5100018440	WASTE MANAGEMENT OF NEW JERSEY INC	3/1/2022	4/5/2022	128		Service				15.21	35.00		50.21	0.00%	0.001
130	5200038582	WESCO DISTRIBUTION, INC	6/17/2022	6/24/2022	110		Service				15.21	7.00		22.21	0.00%	0.001
131	5200038590	WESCO DISTRIBUTION, INC	6/17/2022	6/24/2022	514		Service				15.21	7.00		22.21	0.01%	0.003
132	5100021927	Hart Halsey LLC	4/11/2022	4/22/2022	918		Service				15.21	11.00		26.21	0.02%	0.005
133	5100073055	SPOOKY BROOK HERBARY INC	10/11/2022	11/30/2022	673		Service				15.21	50.00		65.21	0.01%	0.010
134	5200014569	NGS CAYMAN HOLDINGS, L.P	3/9/2022	4/7/2022	216		Service				15.21	29.00		44.21	0.00%	0.002
135	5200051007	WESCO DISTRIBUTION, INC	8/12/2022	8/19/2022	362		Service				15.21	7.00		22.21	0.01%	0.002
136	5100006018	WILLIAM J GUARINI INC.	12/30/2021	2/1/2022	719		Service				15.21	33.00		48.21	0.02%	0.008
137	5200013575	WESCO DISTRIBUTION, INC	3/3/2022	3/11/2022	517		Service				15.21	8.00		23.21	0.01%	0.003
138	5200012802	J. FLETCHER CREAMER & SON, INC.	2/28/2022	3/25/2022	572		Service				15.21	25.00		40.21	0.01%	0.005
139	5200017598	WESCO DISTRIBUTION, INC	3/25/2022	4/1/2022	129		Service				15.21	7.00		22.21	0.00%	0.001
140	5100044203	BAYSHORE RECYCLING CORP	7/26/2022	8/25/2022	790		Service				15.21	30.00		45.21	0.02%	0.008
141	5200025434	JOSEPH M SANZARI INC	4/25/2022	5/13/2022	873		Service				15.21	18.00		33.21	0.02%	0.006
142	5200084535	WESCO DISTRIBUTION, INC	12/28/2022	12/30/2022	809		Service				15.21	2.00		17.21	0.02%	0.003
143	5100001810	CHEMTECH CONSULTING GROUP, INC.	12/21/2021	1/20/2022	317		Service				15.21	30.00		45.21	0.01%	0.003
144	5200003750	PONTOON SOLUTIONS, INC.	1/21/2022	1/27/2022	819		Service				15.21	6.00		21.21	0.02%	0.004
145	5100040459	WESCO DISTRIBUTION, INC	7/14/2022	7/22/2022	916		Service				15.21	8.00		23.21	0.02%	0.005
146	5100011661	TRU-VAL ELECTRICAL CORPORATION	2/16/2022	3/18/2022	305		Service				15.21	30.00		45.21	0.01%	0.003
147	5200037010	WESCO DISTRIBUTION, INC	6/10/2022	6/17/2022	414		Service				15.21	7.00		22.21	0.01%	0.002
148	5200071451	WESCO DISTRIBUTION, INC	11/7/2022	11/14/2022	120		Service				15.21	7.00		22.21	0.00%	0.001
149	5100062974	PARS ENVIRONMENTAL SERVICES	10/14/2022	11/10/2022	545		Service				15.21	27.00		42.21	0.01%	0.005
150	5200013237	WESCO DISTRIBUTION, INC	3/1/2022	3/10/2022	587		Service				15.21	9.00		24.21	0.01%	0.003
151	5100007419	HERMAN'S TRUCKING, INC.	1/11/2022	2/10/2022	320		Service				15.21	30.00		45.21	0.01%	0.003
152	5200075466	NGS CAYMAN HOLDINGS, L.P	11/22/2022	12/21/2022	756		Service				15.21	29.00		44.21	0.02%	0.007
153	5100003541	SOIL SAFE INCORPORATED	1/19/2022	2/18/2022	700		Service				15.21	30.00		45.21	0.02%	0.007
154	5100035435	TRU-VAL ELECTRICAL CORPORATION	6/16/2022	7/15/2022	305		Service				15.21	29.00		44.21	0.01%	0.003
155	5200038562	MARCONE APPLIANCE PARTS COMPANY	6/17/2022	7/15/2022	200		Service				15.21	28.00		43.21	0.00%	0.002
156	5100039723	TOWNSHIP OF LYNDHURST	4/15/2022	7/12/2022	943		Service				15.21	88.00		103.21	0.02%	0.021
157	5200074881	JOHNSTONE SUPPLY	11/21/2022	12/16/2022	264		Service				15.21	25.00		40.21	0.01%	0.002
158	5100001476	HERC RENTALS INC.	12/13/2021	1/12/2022	779		Service				15.21	30.00		45.21	0.02%	0.008
159	5100061493	AIRGAS USA, LLC	9/27/2022	10/27/2022	187		Service				15.21	30.00		45.21	0.00%	0.002
160	5200035635	WESCO DISTRIBUTION, INC	6/3/2022	6/10/2022	667		Service				15.21	7.00		22.21	0.01%	0.003
161	5200017618	WESCO DISTRIBUTION, INC	3/25/2022	4/1/2022	856		Service				15.21	7.00		22.21	0.02%	0.004
162	5100073413	H A FERNOT CO INC	11/15/2022	12/15/2022	306		Service				15.21	30.00		45.21	0.01%	0.003
163	5200030015	WESCO DISTRIBUTION, INC	5/12/2022	5/20/2022	633		Service				15.21	8.00		23.21	0.01%	0.003
164	5100008455	C.G. POWERTECH INC	8/30/2021	2/17/2022	601		Service				15.21	171.00		186.21	0.01%	0.025
165	5200038993	WESCO DISTRIBUTION, INC	6/20/2022	6/27/2022	501		Service				15.21	7.00		22.21	0.01%	0.002
166	5100057702	MATRIX NEW WORLD ENGINEERING, INC	9/15/2022	10/14/2022	190		Service				15.21	29.00		44.21	0.00%	0.002
167	5200067240	WESCO DISTRIBUTION, INC	10/20/2022	10/28/2022	474		Service				15.21	8.00		23.21	0.01%	0.002
168	5100026176	G & W ELECTRIC CO	1/6/2022	5/17/2022	213		Service				15.21	131.00		146.21	0.00%	0.007
169	5200009803	HENKELS & MCCOY, INC.	2/17/2022	2/17/2022	896		Service				15.21	-		15.21	0.02%	0.003

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
170	5200062740	LANTIER CONSTRUCTION COMPANY INC	9/29/2022	10/19/2022	731		Service				15.21	20.00		35.21	0.02%	0.006
171	5100031965	UPPER SADDLE RIVER	6/6/2022	6/13/2022	935		Service				15.21	7.00		22.21	0.02%	0.005
172	5100041262	PARS ENVIRONMENTAL SERVICES	7/14/2022	8/12/2022	849		Service				15.21	29.00		44.21	0.02%	0.008
173	5200003684	WESCO DISTRIBUTION, INC	1/21/2022	1/28/2022	647		Service				15.21	7.00		22.21	0.01%	0.003
174	5200063965	H2M ASSOCIATES, INC	10/4/2022	10/7/2022	699		Service				15.21	3.00		18.21	0.02%	0.003
175	5200011953	HENKELS & MCCOY, INC.	2/28/2022	2/28/2022	865		Service				15.21	-		15.21	0.02%	0.003
176	5100057045	JAN X-Ray Services, Inc.	9/15/2022	10/14/2022	285	Check	Service				15.21	29.00	12.23	56.44	0.01%	0.004
177	5200018362	HENKELS & MCCOY, INC.	3/28/2022	4/14/2022	990		Service				15.21	17.00		32.21	0.02%	0.007
178	5200020689	HI-LINE UTILITY SUPPLY	4/1/2022	4/8/2022	118		Service				15.21	7.00		22.21	0.00%	0.001
179	5100011445	VISUAL COMPUTER SOLUTIONS	2/22/2022	3/1/2022	871		Service				15.21	7.00		22.21	0.02%	0.004
180	5100003557	AIRGAS USA, LLC	1/10/2022	2/9/2022	218		Service				15.21	30.00		45.21	0.00%	0.002
181	5200030336	PONTOON SOLUTIONS, INC.	5/13/2022	5/19/2022	880		Service				15.21	6.00		21.21	0.02%	0.004
182	5200067048	WESCO DISTRIBUTION, INC	10/19/2022	10/28/2022	812		Service				15.21	9.00		24.21	0.02%	0.004
183	5200017010	JOHNSTONE SUPPLY	3/23/2022	4/21/2022	855		Service				15.21	29.00		44.21	0.02%	0.008
184	5200074913	JOSEPH M SANZARI INC	11/21/2022	12/9/2022	873		Service				15.21	18.00		33.21	0.02%	0.006
185	5200017028	MARCONE APPLIANCE PARTS COMPANY	3/23/2022	4/21/2022	553		Service				15.21	29.00		44.21	0.01%	0.005
186	5200084564	WESCO DISTRIBUTION, INC	12/28/2022	1/6/2023	671		Service				15.21	9.00		24.21	0.01%	0.004
187	5100005900	WASTE MANAGEMENT OF NEW JERSEY INC	1/4/2022	2/3/2022	594		Service				15.21	30.00		45.21	0.01%	0.006
188	5100034663	ADVANCED TRAFFIC CONTROL, LLC	5/25/2022	6/24/2022	951		Service				15.21	30.00		45.21	0.02%	0.009
189	5200032897	KEMSCO CONSTRUCTION & EQUIP CO INC	5/24/2022	5/26/2022	442		Service				15.21	2.00		17.21	0.01%	0.002
190	5100060365	PAULUS SOKOLOWSKI & SARTOR INC	9/30/2022	10/28/2022	663		Service				15.21	28.00		43.21	0.01%	0.006
191	5100013684	SEA BOX INC	2/28/2022	3/30/2022	125		Service				15.21	30.00		45.21	0.00%	0.001
192	5200072670	WESCO DISTRIBUTION, INC	11/11/2022	11/18/2022	337		Service				15.21	7.00		22.21	0.01%	0.002
193	5100011427	WILLIAM J GUARINI INC.	2/22/2022	3/24/2022	719		Service				15.21	30.00		45.21	0.02%	0.007
194	5200025239	KEMSCO CONSTRUCTION & EQUIP CO INC	4/25/2022	4/26/2022	544		Service				15.21	1.00		16.21	0.01%	0.002
195	5200045814	NGS CAYMAN HOLDINGS, L.P	7/19/2022	8/17/2022	436		Service				15.21	29.00		44.21	0.01%	0.004
196	5100035166	CHEMTECH CONSULTING GROUP, INC.	6/3/2022	7/1/2022	870		Service				15.21	28.00		43.21	0.02%	0.008
197	5100058890	JOSEPH V. CAPOZZI, INC.	8/27/2022	10/11/2022	434		Service				15.21	45.00		60.21	0.01%	0.006
198	5200001489	JOHNSTONE SUPPLY	1/11/2022	2/9/2022	619		Service				15.21	29.00		44.21	0.01%	0.006
199	5200012361	ROMAN E&G CORP	2/28/2022	3/11/2022	625		Service				15.21	11.00		26.21	0.01%	0.004
200	5100071036	H A FERNOT CO INC	11/10/2022	12/9/2022	300		Service				15.21	29.00		44.21	0.01%	0.003
201	5200041149	HENKELS & MCCOY, INC.	6/29/2022	7/22/2022	696		Service				15.21	23.00		38.21	0.02%	0.006
202	5100020033	WASTE MANAGEMENT OF NEW JERSEY INC	3/1/2022	4/13/2022	181		Service				15.21	43.00		58.21	0.00%	0.002
203	5200005174	WESCO DISTRIBUTION, INC	1/28/2022	2/4/2022	595		Service				15.21	7.00		22.21	0.01%	0.003
204	5200007487	WESCO DISTRIBUTION, INC	2/4/2022	2/11/2022	220		Service				15.21	7.00		22.21	0.00%	0.001
205	5200011777	HENKELS & MCCOY, INC.	2/28/2022	2/28/2022	834		Service				15.21	-		15.21	0.02%	0.003
206	5100026602	ASSOCIATED FIRE PROTECTION	4/25/2022	5/25/2022	700		Service				15.21	30.00		45.21	0.02%	0.007
207	5200012134	KEMSCO CONSTRUCTION & EQUIP CO INC	2/28/2022	3/1/2022	494		Service				15.21	1.00		16.21	0.01%	0.002
208	5200024126	REDMONDS APPLIANCE SALES &	4/20/2022	5/19/2022	231		Service				15.21	29.00		44.21	0.01%	0.002
209	5200053080	WESCO DISTRIBUTION, INC	8/23/2022	9/1/2022	621		Service				15.21	9.00		24.21	0.01%	0.003
210	5100074139	VEHICLE TRACKING SOLUTIONS, LLC	10/24/2022	12/1/2022	167		Service				15.21	38.00		53.21	0.00%	0.002
211	5100039824	HUBBELL GAS UTILITY SOLUTIONS, INC.	6/13/2022	7/13/2022	359		Service				15.21	30.00		45.21	0.01%	0.004
212	5200084822	KEMSCO CONSTRUCTION & EQUIP CO INC	12/29/2022	12/30/2022	962		Service				15.21	1.00		16.21	0.02%	0.003
213	5100000444	IMWOTH LLC	11/30/2021	1/5/2022	195		Service				15.21	36.00		51.21	0.00%	0.002
214	5200056112	WESCO DISTRIBUTION, INC	9/1/2022	9/9/2022	267		Service				15.21	8.00		23.21	0.01%	0.001
215	5200021215	JOHNSTONE SUPPLY	4/4/2022	4/29/2022	107		Service				15.21	25.00		40.21	0.00%	0.001
216	5100030360	SUBURBAN CONSULTING ENGINEERS, INC.	5/20/2022	6/17/2022	483	Check	Service				15.21	28.00	12.23	55.44	0.01%	0.006
217	5100041948	BAYSHORE RECYCLING CORP	7/25/2022	8/24/2022	328		Service				15.21	30.00		45.21	0.01%	0.003
218	5200021250	ELSTER HOLDINGS US, INC.	4/4/2022	4/29/2022	557		Service				15.21	25.00		40.21	0.01%	0.005
219	5200024680	WESCO DISTRIBUTION, INC	4/22/2022	4/29/2022	235		Service				15.21	7.00		22.21	0.01%	0.001
220	5200059544	WESCO DISTRIBUTION, INC	9/16/2022	9/23/2022	371		Service				15.21	7.00		22.21	0.01%	0.002
221	5200040249	WESCO DISTRIBUTION, INC	6/24/2022	7/1/2022	216		Service				15.21	7.00		22.21	0.00%	0.001
222	5200047901	WESCO DISTRIBUTION, INC	7/27/2022	8/5/2022	257		Service				15.21	9.00		24.21	0.01%	0.001
223	5200051796	ROMAN E&G CORP	8/18/2022	9/16/2022	300		Service				15.21	29.00		44.21	0.01%	0.003
224	5200066822	E H ALLEN & SON INC	10/19/2022	11/17/2022	975		Service				15.21	29.00		44.21	0.02%	0.009
225	5200025217	KEMSCO CONSTRUCTION & EQUIP CO INC	4/25/2022	4/29/2022	416		Service				15.21	4.00		19.21	0.01%	0.002
226	5100017985	VEOLIA ENVIRONMENTAL SERVICES	4/1/2022	4/29/2022	801		Service				15.21	28.00		43.21	0.02%	0.008
227	5200003311	WESCO DISTRIBUTION, INC	1/19/2022	1/28/2022	940		Service				15.21	9.00		24.21	0.02%	0.005

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
228	5100064906	ELSTER HOLDINGS US, INC.	10/20/2022	11/18/2022	602		Service				15.21	29.00		44.21	0.01%	0.006
229	5100026479	PSC INDUSTRIAL OUTSOURCING, LP	5/4/2022	6/3/2022	402		Service				15.21	30.00		45.21	0.01%	0.004
230	5200013436	MARCONE APPLIANCE PARTS COMPANY	3/2/2022	3/31/2022	590		Service				15.21	29.00		44.21	0.01%	0.006
231	5100026444	H A FERNOT CO INC	4/27/2022	5/27/2022	754		Service				15.21	30.00		45.21	0.02%	0.008
232	5100017021	MANCINE OPTICAL CO	2/28/2022	3/30/2022	100		Service				15.21	30.00		45.21	0.00%	0.001
233	5200041895	Atlantic InfraRed, Inc	6/30/2022	7/8/2022	780		Service				15.21	8.00		23.21	0.02%	0.004
234	5100055724	WASTE MANAGEMENT OF NEW JERSEY INC	8/1/2022	9/21/2022	100		Service				15.21	51.00		66.21	0.00%	0.001
235	5100010720	BAYSHORE RECYCLING CORP	2/22/2022	3/24/2022	729		Service				15.21	30.00		45.21	0.02%	0.007
236	5100061467	SECURITAS SECURITY SERVICES USA INC	10/6/2022	11/4/2022	969		Service				15.21	29.00		44.21	0.02%	0.009
237	5200037429	WESCO DISTRIBUTION, INC	6/13/2022	6/17/2022	338		Service				15.21	4.00		19.21	0.01%	0.001
238	5200034610	SUBURBAN CONSULTING ENGINEERS, INC.	5/30/2022	6/17/2022	340		Service				15.21	18.00		33.21	0.01%	0.002
239	5100061150	PETROLEUM TRADERS CORP.	9/26/2022	10/26/2022	6,902		Service				15.21	30.00		45.21	0.15%	0.069
240	5100025969	HERC RENTALS INC.	4/15/2022	5/13/2022	1,295		Service				15.21	28.00		43.21	0.03%	0.012
241	5100064927	HERC RENTALS INC.	10/25/2022	11/23/2022	2,500		Service				15.21	29.00		44.21	0.06%	0.024
242	5100034428	BAYSHORE RECYCLING CORP	5/31/2022	6/30/2022	1,140		Service				15.21	30.00		45.21	0.03%	0.011
243	5100002288	PETROLEUM TRADERS CORP.	1/5/2022	2/4/2022	3,858		Service				15.21	30.00		45.21	0.09%	0.038
244	5100065684	VISUAL COMPUTER SOLUTIONS	10/27/2022	11/7/2022	1,724		Service				15.21	11.00		26.21	0.04%	0.010
245	5200008073	LANTIER CONSTRUCTION COMPANY INC	2/9/2022	2/10/2022	2,023		Service				15.21	1.00		16.21	0.04%	0.007
246	5100028619	MIKE WATERS OIL TANKS	4/20/2022	5/20/2022	2,122		Service				15.21	30.00		45.21	0.05%	0.021
247	5100059489	MATRIX NEW WORLD ENGINEERING, INC	10/13/2022	11/10/2022	2,588		Service				15.21	28.00		43.21	0.06%	0.025
248	5100053589	WASTE MANAGEMENT OF NEW JERSEY INC	9/1/2022	9/30/2022	1,455		Service				15.21	29.00		44.21	0.03%	0.014
249	5100009298	HARSCO CORPORATION	3/3/2022	4/1/2022	2,335		Service				15.21	29.00		44.21	0.05%	0.023
250	5200050705	WESCO DISTRIBUTION, INC	8/10/2022	8/19/2022	5,593		Service				15.21	9.00		24.21	0.12%	0.030
251	5100000786	CLEAN HARBORS ENVIRONMENTAL SVCS CO	1/18/2022	2/17/2022	1,967		Service				15.21	30.00		45.21	0.04%	0.020
252	5200036384	ACUITY BRANDS LIGHTING	6/8/2022	7/7/2022	5,100		Service				15.21	29.00		44.21	0.11%	0.050
253	5200000922	RR DONNELLEY & SONS COMPANY	1/7/2022	2/3/2022	7,770		Service				15.21	27.00		42.21	0.17%	0.072
254	5100046283	INTERSTATE WASTE SERVICES OF	7/25/2022	8/24/2022	2,700		Service				15.21	30.00		45.21	0.06%	0.027
255	5100007614	PETROLEUM TRADERS CORP.	1/28/2022	2/25/2022	4,404		Service				15.21	28.00		43.21	0.10%	0.042
256	5200043350	WEG Transformers USA LLC	7/7/2022	8/5/2022	9,728		Service				15.21	29.00		44.21	0.21%	0.095
257	5200048201	LANTIER CONSTRUCTION COMPANY INC	7/28/2022	8/19/2022	11,685		Service				15.21	22.00		37.21	0.26%	0.096
258	5200066106	WESCO DISTRIBUTION, INC	10/13/2022	10/21/2022	13,340		Service				15.21	8.00		23.21	0.29%	0.068
259	5200063979	ALL GREEN LIGHTING	10/4/2022	11/2/2022	22,400		Service				15.21	29.00		44.21	0.49%	0.218
260	5200024032	SIGNIFY NORTH AMERICA CORPORATION	4/19/2022	5/18/2022	12,740		Service				15.21	29.00		44.21	0.28%	0.124
261	5200058888	J. FLETCHER CREAMER & SON, INC.	9/14/2022	9/15/2022	25,924		Service				15.21	1.00		16.21	0.57%	0.093
262	5200033751	JOSEPH M SANZARI INC	5/27/2022	6/22/2022	11,118		Service				15.21	26.00		41.21	0.24%	0.101
263	5200045919	LANTIER CONSTRUCTION COMPANY INC	7/20/2022	8/5/2022	14,325		Service				15.21	16.00		31.21	0.32%	0.098
264	5100004037	BAYSHORE RECYCLING CORP	1/7/2022	2/4/2022	11,926		Service				15.21	28.00		43.21	0.26%	0.114
265	5200080422	WESCO DISTRIBUTION, INC	12/12/2022	12/19/2022	64,288		Service				15.21	7.00		22.21	1.42%	0.315
266	5200033437	COOPER LIGHTING LLC	5/26/2022	6/24/2022	10,115		Service				15.21	29.00		44.21	0.22%	0.099
267	5100035033	City of Union City	6/17/2022	6/22/2022	11,043		Service				15.21	5.00		20.21	0.24%	0.049
268	5100065669	REVCO SOLUTIONS, INC.	11/1/2022	12/1/2022	10,421		Service				15.21	30.00		45.21	0.23%	0.104
269	5200003023	WESCO DISTRIBUTION, INC	1/18/2022	1/27/2022	10,800		Service				15.21	9.00		24.21	0.24%	0.058
270	5100062357	BAYSHORE RECYCLING CORP	10/18/2022	11/17/2022	13,673		Service				15.21	30.00		45.21	0.30%	0.136
271	5100039040	1 800 HEATERS	7/6/2022	7/11/2022	17,310		Service				15.21	5.00		20.21	0.38%	0.077
272	5200067389	KOPPERS UTILITY AND	10/21/2022	10/24/2022	10,879		Service				15.21	3.00		18.21	0.24%	0.044
273	5100018933	INGERSOLL RAND AIR CENTER	3/18/2022	4/14/2022	49,350		Service				15.21	27.00		42.21	1.09%	0.459
274	5200015932	MAGRANN ASSOCIATES	3/18/2022	3/21/2022	11,324		Service				15.21	3.00		18.21	0.25%	0.045
275	5100006311	DG3 NORTH AMERICA, INC	1/19/2022	2/23/2022	26,198		Service				15.21	35.00		50.21	0.58%	0.290
276	5100030888	UTILIMARC	6/7/2022	7/7/2022	21,000		Service				15.21	30.00		45.21	0.46%	0.209
277	5200047819	LANTIER CONSTRUCTION COMPANY INC	7/27/2022	8/10/2022	20,560		Service				15.21	14.00		29.21	0.45%	0.132
278	5200039790	FERREIRA CONSTRUCTION CO. INC.	6/23/2022	6/24/2022	35,966		Service				15.21	1.00		16.21	0.79%	0.128
279	5200045981	LEOTEK ELECTRONICS USA LLC	7/20/2022	9/16/2022	12,300		Service				15.21	58.00		73.21	0.27%	0.198
280	5200023618	FERREIRA CONSTRUCTION CO. INC.	4/15/2022	5/6/2022	15,850		Service				15.21	21.00		36.21	0.35%	0.126
281	5200025821	J. FLETCHER CREAMER & SON, INC.	4/25/2022	5/20/2022	10,593		Service				15.21	25.00		40.21	0.23%	0.094
282	5200034762	FERREIRA CONSTRUCTION CO. INC.	5/31/2022	6/17/2022	30,683		Service				15.21	17.00		32.21	0.68%	0.218
283	5200067381	WEG Transformers USA LLC	10/21/2022	11/18/2022	37,195		Service				15.21	28.00		43.21	0.82%	0.354
284	5200062392	NOCAR CONTRACTORS	9/28/2022	10/19/2022	43,023		Service				15.21	21.00		36.21	0.95%	0.343
285	5200081245	ELSTER AMERICAN METER COMPANY LLC	12/15/2022	1/13/2023	29,909		Service				15.21	29.00		44.21	0.66%	0.291

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
286	5200076910	HENKELS & MCCOY, INC.	11/29/2022	12/16/2022	30,481		Service				15.21	17.00		32.21	0.67%	0.216
287	5200004711	WESCO DISTRIBUTION, INC	1/26/2022	2/4/2022	12,319		Service				15.21	9.00		24.21	0.27%	0.066
288	5100057907	CHEMTECH CONSULTING GROUP, INC.	9/19/2022	10/19/2022	17,298		Service				15.21	30.00		45.21	0.38%	0.172
289	5100019398	TRC ENVIRONMENTAL CORPORATION	4/6/2022	5/6/2022	15,771		Service				15.21	30.00		45.21	0.35%	0.157
290	5100059166	UNITED SITE SERVICES	9/7/2022	10/7/2022	40,000		Service				15.21	30.00		45.21	0.88%	0.398
291	5100007063	WILLIAM J GUARINI INC.	2/9/2022	2/14/2022	18,003		Service				15.21	5.00		20.21	0.40%	0.080
292	5100033046	PETROLEUM TRADERS CORP.	6/2/2022	7/1/2022	14,588		Service				15.21	29.00		44.21	0.32%	0.142
293	5100030156	SUNRISE TECHNOLOGIES, INC.	2/9/2022	6/2/2022	28,000		Service				15.21	113.00		128.21	0.62%	0.791
294	5200040859	HENKELS & MCCOY, INC.	6/27/2022	7/15/2022	13,575		Service				15.21	18.00		33.21	0.30%	0.099
295	5200070024	LANTIER CONSTRUCTION COMPANY INC	11/1/2022	11/18/2022	21,054		Service				15.21	17.00		32.21	0.46%	0.149
296	5200035334	LANTIER CONSTRUCTION COMPANY INC	6/3/2022	6/6/2022	16,715		Service				15.21	3.00		18.21	0.37%	0.067
297	5200020634	ROMAN E&G CORP	4/1/2022	4/13/2022	17,015		Service				15.21	12.00		27.21	0.37%	0.102
298	5200072392	NOCAR CONTRACTORS	11/10/2022	12/1/2022	36,836		Service				15.21	21.00		36.21	0.81%	0.294
299	5200076632	JOSEPH M SANZARI INC	11/28/2022	12/16/2022	14,759		Service				15.21	18.00		33.21	0.33%	0.108
300	5200020968	J. FLETCHER CREAMER & SON, INC.	4/1/2022	4/22/2022	13,552		Service				15.21	21.00		36.21	0.30%	0.108
301	5200069739	FERREIRA CONSTRUCTION CO. INC.	10/31/2022	11/16/2022	10,208		Service				15.21	16.00		31.21	0.22%	0.070
302	5100026857	BAYSHORE RECYCLING CORP	5/5/2022	6/3/2022	42,951		Service				15.21	29.00		44.21	0.95%	0.418
303	5200067839	NGS CAYMAN HOLDINGS, L.P	10/24/2022	11/18/2022	16,254		Service				15.21	25.00		40.21	0.36%	0.144
304	5100013256	WESCO DISTRIBUTION, INC	3/11/2022	3/21/2022	17,386		Service				15.21	10.00		25.21	0.38%	0.097
305	5200006352	J. FLETCHER CREAMER & SON, INC.	1/31/2022	2/4/2022	15,085		Service				15.21	4.00		19.21	0.33%	0.064
306	5100072833	KEROTEST MFG CORP	11/18/2022	12/16/2022	33,300		Service				15.21	28.00		43.21	0.73%	0.317
307	5100014029	TOWNSHIP OF SADDLE BROOK	2/16/2022	3/17/2022	11,112		Service				15.21	29.00		44.21	0.24%	0.108
308	5200028107	FERREIRA CONSTRUCTION CO. INC.	5/2/2022	5/20/2022	49,718		Service				15.21	18.00		33.21	1.10%	0.364
309	5200041305	JOSEPH M SANZARI INC	6/29/2022	7/15/2022	16,304		Service				15.21	16.00		31.21	0.36%	0.112
310	5100079183	P&N DISTRIBUTION CORPORATION	12/14/2022	1/13/2023	18,479		Service				15.21	30.00		45.21	0.41%	0.184
311	5200050742	HENKELS & MCCOY, INC.	8/10/2022	9/1/2022	44,494		Service				15.21	22.00		37.21	0.98%	0.365
312	5100076996	GARTNER INC	11/25/2022	12/23/2022	68,200		Service				15.21	28.00		43.21	1.50%	0.649
313	5100063669	SEL ENGINEERING SERVICES INC	10/14/2022	11/10/2022	12,158		Service				15.21	27.00		42.21	0.27%	0.113
314	5200013423	COOPER POWER SYSTEMS DIVISION	3/2/2022	3/31/2022	20,600		Service				15.21	29.00		44.21	0.45%	0.201
315	5200020128	NOCAR CONTRACTORS	3/31/2022	4/22/2022	14,960		Service				15.21	22.00		37.21	0.33%	0.123
316	5200069307	SA AND SONS CONSTRUCTION CO INC *	10/31/2022	11/1/2022	14,599		Service				15.21	1.00		16.21	0.32%	0.052
317	5100080126	ABBOTT CONTRACTING	12/14/2022	1/13/2023	10,132		Service				15.21	30.00		45.21	0.22%	0.101
318	5200004148	LANTIER CONSTRUCTION COMPANY INC	1/25/2022	2/9/2022	11,560		Service				15.21	15.00		30.21	0.25%	0.077
319	5200049606	WESCO DISTRIBUTION, INC	8/3/2022	8/12/2022	13,299		Service				15.21	9.00		24.21	0.29%	0.071
320	5200047518	FERREIRA CONSTRUCTION CO. INC.	7/26/2022	8/12/2022	13,320		Service				15.21	17.00		32.21	0.29%	0.095
321	5200040124	JOSEPH M SANZARI INC	6/24/2022	7/21/2022	10,038		Service				15.21	27.00		42.21	0.22%	0.093
322	5100011450	ATLAS FLASHER & SUPPLY CO., INC.	2/14/2022	3/16/2022	23,887		Service				15.21	30.00		45.21	0.53%	0.238
323	5200042363	HENKELS & MCCOY, INC.	7/1/2022	7/28/2022	12,345		Service				15.21	27.00		42.21	0.27%	0.115
324	5200081390	NOCAR CONTRACTORS	12/15/2022	1/6/2023	13,388		Service				15.21	22.00		37.21	0.29%	0.110
325	5200044622	ROMAN E&G CORP	7/14/2022	7/27/2022	10,176		Service				15.21	13.00		28.21	0.22%	0.063
326	5200040965	COOPER POWER SYSTEMS DIVISION	6/28/2022	7/27/2022	15,565		Service				15.21	29.00		44.21	0.34%	0.152
327	5200023631	FERREIRA CONSTRUCTION CO. INC.	4/15/2022	5/11/2022	11,730		Service				15.21	26.00		41.21	0.26%	0.106
328	5100063227	HARSCO CORPORATION	10/12/2022	11/10/2022	16,676		Service				15.21	29.00		44.21	0.37%	0.162
329	5200019208	LANTIER CONSTRUCTION COMPANY INC	3/30/2022	4/14/2022	16,715		Service				15.21	15.00		30.21	0.37%	0.111
330	5200005570	HENKELS & MCCOY, INC.	1/31/2022	1/31/2022	12,250		Service				15.21	-		15.21	0.27%	0.041
331	5100007949	BAYSHORE RECYCLING CORP	2/7/2022	3/9/2022	14,896		Service				15.21	30.00		45.21	0.33%	0.148
332	5200029854	J. FLETCHER CREAMER & SON, INC.	5/12/2022	5/27/2022	10,333		Service				15.21	15.00		30.21	0.23%	0.069
333	5200079398	THE OKONITE CO.	12/7/2022	12/16/2022	50,595		Service				15.21	9.00		24.21	1.11%	0.270
334	5100039736	K. MOOREA CO LLC	7/5/2022	7/13/2022	44,544		Service				15.21	8.00		23.21	0.98%	0.228
335	5200069711	HENKELS & MCCOY, INC.	10/31/2022	11/10/2022	13,545		Service				15.21	10.00		25.21	0.30%	0.075
336	5100031545	CONTRACT CALLERS, INC.	6/1/2022	7/1/2022	77,400		Service				15.21	30.00		45.21	1.71%	0.771
337	5100029725	A Y MCDONALD MFG CO	5/20/2022	6/14/2022	10,800		Service				15.21	25.00		40.21	0.24%	0.096
338	5100030402	RIGGS DISTLER & COMPANY INC	4/12/2022	5/31/2022	48,110		Service				15.21	49.00		64.21	1.06%	0.681
339	5200074041	MILLER PIPELINE CORP	11/18/2022	11/21/2022	20,870		Service				15.21	3.00		18.21	0.46%	0.084
340	5200027424	NOCAR CONTRACTORS	4/29/2022	5/13/2022	29,044		Service				15.21	14.00		29.21	0.64%	0.187
341	5200065517	G & W ELECTRIC CO	10/12/2022	11/10/2022	27,600		Service				15.21	29.00		44.21	0.61%	0.269
342	5200033647	KEMSCO CONSTRUCTION & EQUIP CO INC	5/27/2022	6/1/2022	10,738		Service				15.21	5.00		20.21	0.24%	0.048
343	5100074642	WESCO DISTRIBUTION, INC	10/14/2022	12/9/2022	12,736		Service				15.21	56.00		71.21	0.28%	0.200

Line No.	Document Number	Vendor Name	Invoice Date	Payment Date	Amount	Payment Method	Product or Service? (If Known)	Product Delivery Date (If known)	Period Start	Period End	Service Lead	Payment Lead	Float	Total Lead	Weighting	Weighted Lead
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
344	5100035744	BAYSHORE RECYCLING CORP	6/15/2022	7/15/2022	10,477		Service				15.21	30.00		45.21	0.23%	0.104
345	5200036453	FERREIRA CONSTRUCTION CO. INC.	6/8/2022	6/9/2022	23,210		Service				15.21	1.00		16.21	0.51%	0.083
346	5200037855	FERREIRA CONSTRUCTION CO. INC.	6/14/2022	7/8/2022	29,506		Service				15.21	24.00		39.21	0.65%	0.255
347	5100054999	WILLIAM J GUARINI INC.	9/13/2022	9/26/2022	44,025		Service				15.21	13.00		28.21	0.97%	0.274
348	5200015658	ROMAN E&G CORP	3/16/2022	3/30/2022	14,796		Service				15.21	14.00		29.21	0.33%	0.095
349	5200077250	NOCAR CONTRACTORS	11/29/2022	12/2/2022	14,012		Service				15.21	3.00		18.21	0.31%	0.056
350	5200024143	JOHNSTONE SUPPLY	4/20/2022	5/19/2022	22,399		Service				15.21	29.00		44.21	0.49%	0.218
351	5200062798	TILCON NEW YORK INC.	9/29/2022	9/30/2022	60,130		Service				15.21	1.00		16.21	1.32%	0.215
352	5200042362	HENKELS & MCCOY, INC.	7/1/2022	7/28/2022	16,875		Service				15.21	27.00		42.21	0.37%	0.157
353	5200026988	LANTIER CONSTRUCTION COMPANY INC	4/29/2022	6/3/2022	11,435		Service				15.21	35.00		50.21	0.25%	0.126
354	5100081640	City of Union City	11/23/2022	12/30/2022	10,498		Service				15.21	37.00		52.21	0.23%	0.121
355	5100016134	Osmose Utilities Services, Inc.	1/13/2022	3/24/2022	17,679		Service				15.21	70.00		85.21	0.39%	0.332
356	5100046947	NELSON TREE SERVICE INC	8/11/2022	9/9/2022	20,536		Service				15.21	29.00		44.21	0.45%	0.200
357	5200078266	LANTIER CONSTRUCTION COMPANY INC	12/1/2022	12/2/2022	20,125		Service				15.21	1.00		16.21	0.44%	0.072
358	5100035213	K. MOOREA CO LLC	4/8/2022	6/30/2022	14,160		Service				15.21	83.00		98.21	0.31%	0.306
359	5200072394	NOCAR CONTRACTORS	11/10/2022	12/2/2022	14,845		Service				15.21	22.00		37.21	0.33%	0.122
360	5100028303	VISUAL COMPUTER SOLUTIONS	4/28/2022	5/18/2022	10,403		Service				15.21	20.00		35.21	0.23%	0.081
361	5100017562	WESCO DISTRIBUTION, INC	3/11/2022	4/5/2022	63,407		Service				15.21	25.00		40.21	1.40%	0.562
362	5100072235	NIELSEN FORD OF MORRISTOWN	10/27/2022	11/28/2022	32,526		Service				15.21	32.00		47.21	0.72%	0.338
363	5200078774	WESCO DISTRIBUTION, INC	12/2/2022	12/9/2022	39,387		Service				15.21	7.00		22.21	0.87%	0.193
364	5100032832	ACCENTURE LLP	6/1/2022	7/1/2022	31,603		Service				15.21	30.00		45.21	0.70%	0.315
365	5100057737	Hart Halsey LLC	6/7/2022	9/30/2022	49,032		Service				15.21	115.00		130.21	1.08%	1.406
366	5200022698	Atlantic InfraRed, Inc	4/14/2022	4/18/2022	16,784		Service				15.21	4.00		19.21	0.37%	0.071
367	5100063278	NELSON TREE SERVICE INC	10/7/2022	11/4/2022	10,158		Service				15.21	28.00		43.21	0.22%	0.097
368	5100000864	BAYSHORE RECYCLING CORP	1/6/2022	2/4/2022	17,961		Service				15.21	29.00		44.21	0.40%	0.175
369	5100024613	TASK FORCE ONE INC	4/8/2022	5/6/2022	13,752		Service				15.21	28.00		43.21	0.30%	0.131
370	5200014095	LANTIER CONSTRUCTION COMPANY INC	3/8/2022	3/30/2022	15,200		Service				15.21	22.00		37.21	0.33%	0.125
371	5200060454	SA AND SONS CONSTRUCTION CO INC *	9/21/2022	10/14/2022	16,916		Service				15.21	23.00		38.21	0.37%	0.142
372	5200031057	ERMCO	5/17/2022	6/15/2022	15,608		Service				15.21	29.00		44.21	0.34%	0.152
373	5200075976	LANTIER CONSTRUCTION COMPANY INC	11/24/2022	11/29/2022	11,465		Service				15.21	5.00		20.21	0.25%	0.051
374	5100043059	TSI TURTLE SERVICES, LLC D/B/A TSI	5/1/2022	8/3/2022	40,320		Service				15.21	94.00		109.21	0.89%	0.970
375	5200042010	ELSTER HOLDINGS US, INC.	6/30/2022	7/29/2022	16,421		Service				15.21	29.00		44.21	0.36%	0.160
376	5200055330	JOSEPH M SANZARI INC	8/31/2022	9/23/2022	22,600		Service				15.21	23.00		38.21	0.50%	0.190
377	5200084687	SA AND SONS CONSTRUCTION CO INC *	12/29/2022	12/30/2022	10,731		Service				15.21	1.00		16.21	0.24%	0.038
378	5200032323	HENKELS & MCCOY, INC.	5/23/2022	6/15/2022	13,438		Service				15.21	23.00		38.21	0.30%	0.113
379	5100015801	J.SUPOR REALTY LLC	2/28/2022	3/30/2022	33,000		Service				15.21	30.00		45.21	0.73%	0.329
380	5200048691	TILCON NEW YORK INC.	7/29/2022	8/24/2022	197,016		Service				15.21	26.00		41.21	4.34%	1.789
381	5100019255	POWERCON CORPORATION	4/5/2022	4/8/2022	102,000		Service				15.21	3.00		18.21	2.25%	0.409
382	5100003317	KEMSCO CONSTRUCTION & EQUIP CO INC	1/10/2022	2/9/2022	128,266		Service				15.21	30.00		45.21	2.83%	1.277
383	5100037825	Burns & McDonnell	6/26/2022	7/7/2022	1,203,177		Service				15.21	11.00		26.21	26.51%	6.947
					$ 4,539,296											36.10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
PURCHASED POWER

Weighted Lead 35.83 days

Vendor		Amount	Service Beginning	Service Ending	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Basic Generation Service	$	154,769,321	1/1/2022	1/31/2022	2/22/2022	15.50	22.00	37.50	9.23%	3.46
Basic Generation Service		118,367,859	2/1/2022	2/28/2022	3/21/2022	14.00	21.00	35.00	7.06%	2.47
Basic Generation Service		109,114,677	3/1/2022	3/31/2022	4/20/2022	15.50	20.00	35.50	6.51%	2.31
Basic Generation Service		92,301,992	4/1/2022	4/30/2022	5/20/2022	15.00	20.00	35.00	5.50%	1.93
Basic Generation Service		115,577,963	5/1/2022	5/31/2022	6/20/2022	15.50	20.00	35.50	6.89%	2.45
Basic Generation Service		147,974,049	6/1/2022	6/30/2022	7/20/2022	15.00	20.00	35.00	8.82%	3.09
Basic Generation Service		215,512,016	7/1/2022	7/31/2022	8/22/2022	15.50	22.00	37.50	12.85%	4.82
Basic Generation Service		215,453,286	8/1/2022	8/31/2022	9/20/2022	15.50	20.00	35.50	12.85%	4.56
Basic Generation Service		131,825,634	9/1/2022	9/30/2022	10/20/2022	15.00	20.00	35.00	7.86%	2.75
Basic Generation Service		104,896,787	10/1/2022	10/31/2022	11/21/2022	15.50	21.00	36.50	6.25%	2.28
Basic Generation Service		114,706,532	11/1/2022	11/30/2022	12/20/2022	15.00	20.00	35.00	6.84%	2.39
Basic Generation Service		155,465,365	12/1/2022	12/31/2022	1/20/2023	15.50	20.00	35.50	9.27%	3.29
Purchased Electric Power		192,385	1/1/2022	1/31/2022	3/1/2022	15.50	29.00	44.50	0.01%	0.01
Purchased Electric Power		66,915	2/1/2022	2/28/2022	4/1/2022	14.00	32.00	46.00	0.00%	0.00
Purchased Electric Power		63,346	3/1/2022	3/31/2022	5/1/2022	15.50	31.00	46.50	0.00%	0.00
Purchased Electric Power		87,462	4/1/2022	4/30/2022	6/1/2022	15.00	32.00	47.00	0.01%	0.00
Purchased Electric Power		91,200	5/1/2022	5/31/2022	7/1/2022	15.50	31.00	46.50	0.01%	0.00
Purchased Electric Power		135,995	6/1/2022	6/30/2022	8/1/2022	15.00	32.00	47.00	0.01%	0.00
Purchased Electric Power		151,246	7/1/2022	7/31/2022	9/1/2022	15.50	32.00	47.50	0.01%	0.00
Purchased Electric Power		182,616	8/1/2022	8/31/2022	10/1/2022	15.50	31.00	46.50	0.01%	0.01
Purchased Electric Power		73,177	9/1/2022	9/30/2022	11/1/2022	15.00	32.00	47.00	0.00%	0.00
Purchased Electric Power		48,110	10/1/2022	10/31/2022	12/1/2022	15.50	31.00	46.50	0.00%	0.00
Purchased Electric Power		38,666	11/1/2022	11/30/2022	1/1/2023	15.00	32.00	47.00	0.00%	0.00
Purchased Electric Power		203,893	12/1/2022	12/31/2022	2/1/2023	15.50	32.00	47.50	0.01%	0.01
	$	1,677,300,492								35.83

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
NATURAL GAS PURCHASES

Weighted Lead 35.63 days

Month (A)		Amount (B)	Service Beginning (C)	Service Ending (D)	Payment Date (E)	Service Lead Time (F)	Payment Lead Time (G)	Total Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
January 2022	$	193,540,451	1/1/2022	1/31/2022	2/22/2022	15.50	22.00	37.50	15.67%	5.88
February 2022		184,076,649	2/1/2022	2/28/2022	3/21/2022	14.00	21.00	35.00	14.91%	5.22
March 2022		147,519,085	3/1/2022	3/31/2022	4/19/2022	15.50	19.00	34.50	11.95%	4.12
April 2022		104,617,200	4/1/2022	4/30/2022	5/20/2022	15.00	20.00	35.00	8.47%	2.97
May 2022		56,213,368	5/1/2022	5/31/2022	6/21/2022	15.50	21.00	36.50	4.55%	1.66
June 2022		36,492,646	6/1/2022	6/30/2022	7/20/2022	15.00	20.00	35.00	2.96%	1.03
July 2022		17,963,154	7/1/2022	7/31/2022	8/22/2022	15.50	22.00	37.50	1.45%	0.55
August 2022		23,790,859	8/1/2022	8/31/2022	9/20/2022	15.50	20.00	35.50	1.93%	0.68
September 2022		34,402,961	9/1/2022	9/30/2022	10/20/2022	15.00	20.00	35.00	2.79%	0.98
October 2022		77,976,289	10/1/2022	10/31/2022	11/21/2022	15.50	21.00	36.50	6.31%	2.30
November 2022		144,479,451	11/1/2022	11/30/2022	12/20/2022	15.00	20.00	35.00	11.70%	4.10
December 2022		213,744,951	12/1/2022	12/31/2022	1/20/2023	15.50	20.00	35.50	17.31%	6.14
	$	1,234,817,065								35.63

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
TAXES OTHER THAN INCOME TAXES

Weighted Lead Time:	Amount	Days	Weighting Factor	Weighted Lead	
Payroll Taxes	$ 73,247,449	16.96	79.28%	13.45	
Real Estate Tax	17,848,322	(39.09)	19.32%	(7.55)	
Newark City Tax	1,297,185	75.46	1.40%	1.06	
	$ 92,392,957			6.95	days

Payroll Taxes

Weekly Payroll (A)	Pay Period Beginning (B)	Pay Period End (C)	Paid On (D)	Net Pay (E)	Midpoint of Pay Period (F)	Payment Lead Time (G)	Total Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
Social Security/ Medicare	12/20/2021	12/26/2021	1/5/2022	$ 837,056	3.50	10.00	13.50	1.70%	0.23
Social Security/ Medicare	12/27/2021	1/2/2022	1/12/2022	815,531	3.50	10.00	13.50	1.66%	0.22
Social Security/ Medicare	1/3/2022	1/9/2022	1/19/2022	910,812	3.50	10.00	13.50	1.85%	0.25
Social Security/ Medicare	1/10/2022	1/16/2022	1/26/2022	909,942	3.50	10.00	13.50	1.85%	0.25
Social Security/ Medicare	1/17/2022	1/23/2022	2/2/2022	1,029,681	3.50	10.00	13.50	2.10%	0.28
Social Security/ Medicare	1/24/2022	1/30/2022	2/9/2022	989,222	3.50	10.00	13.50	2.01%	0.27
Social Security/ Medicare	1/31/2022	2/6/2022	2/16/2022	872,164	3.50	10.00	13.50	1.77%	0.24
Social Security/ Medicare	2/7/2022	2/13/2022	2/23/2022	915,272	3.50	10.00	13.50	1.86%	0.25
Social Security/ Medicare	2/14/2022	2/20/2022	3/2/2022	912,073	3.50	10.00	13.50	1.86%	0.25
Social Security/ Medicare	2/21/2022	2/27/2022	3/9/2022	924,764	3.50	10.00	13.50	1.88%	0.25
Social Security/ Medicare	2/28/2022	3/6/2022	3/16/2022	917,057	3.50	10.00	13.50	1.87%	0.25
Social Security/ Medicare	3/7/2022	3/13/2022	3/23/2022	945,343	3.50	10.00	13.50	1.92%	0.26
Social Security/ Medicare	3/14/2022	3/20/2022	3/30/2022	929,018	3.50	10.00	13.50	1.89%	0.26
Social Security/ Medicare	3/21/2022	3/27/2022	4/6/2022	922,296	3.50	10.00	13.50	1.88%	0.25
Social Security/ Medicare	3/28/2022	4/3/2022	4/13/2022	936,678	3.50	10.00	13.50	1.91%	0.26
Social Security/ Medicare	4/4/2022	4/10/2022	4/20/2022	933,358	3.50	10.00	13.50	1.90%	0.26
Social Security/ Medicare	4/11/2022	4/17/2022	4/27/2022	906,501	3.50	10.00	13.50	1.84%	0.25
Social Security/ Medicare	4/18/2022	4/24/2022	5/4/2022	933,366	3.50	10.00	13.50	1.90%	0.26
Social Security/ Medicare	4/25/2022	5/1/2022	5/11/2022	911,942	3.50	10.00	13.50	1.86%	0.25
Social Security/ Medicare	5/2/2022	5/8/2022	5/18/2022	931,914	3.50	10.00	13.50	1.90%	0.26
Social Security/ Medicare	5/9/2022	5/15/2022	5/25/2022	989,609	3.50	10.00	13.50	2.01%	0.27
Social Security/ Medicare	5/16/2022	5/22/2022	6/1/2022	994,061	3.50	10.00	13.50	2.02%	0.27
Social Security/ Medicare	5/23/2022	5/29/2022	6/8/2022	950,388	3.50	10.00	13.50	1.93%	0.26
Social Security/ Medicare	5/30/2022	6/5/2022	6/15/2022	974,357	3.50	10.00	13.50	1.98%	0.27
Social Security/ Medicare	6/6/2022	6/12/2022	6/22/2022	970,411	3.50	10.00	13.50	1.97%	0.27
Social Security/ Medicare	6/13/2022	6/19/2022	6/29/2022	948,273	3.50	10.00	13.50	1.93%	0.26
Social Security/ Medicare	6/20/2022	6/26/2022	7/6/2022	947,769	3.50	10.00	13.50	1.93%	0.26
Social Security/ Medicare	6/27/2022	7/3/2022	7/13/2022	904,122	3.50	10.00	13.50	1.84%	0.25
Social Security/ Medicare	7/4/2022	7/10/2022	7/20/2022	950,691	3.50	10.00	13.50	1.93%	0.26
Social Security/ Medicare	7/11/2022	7/17/2022	7/27/2022	952,795	3.50	10.00	13.50	1.94%	0.26
Social Security/ Medicare	7/18/2022	7/24/2022	8/3/2022	976,649	3.50	10.00	13.50	1.99%	0.27
Social Security/ Medicare	7/25/2022	7/31/2022	8/10/2022	945,355	3.50	10.00	13.50	1.92%	0.26
Social Security/ Medicare	8/1/2022	8/7/2022	8/17/2022	948,742	3.50	10.00	13.50	1.93%	0.26
Social Security/ Medicare	8/8/2022	8/14/2022	8/24/2022	942,978	3.50	10.00	13.50	1.92%	0.26
Social Security/ Medicare	8/15/2022	8/21/2022	8/31/2022	940,255	3.50	10.00	13.50	1.91%	0.26
Social Security/ Medicare	8/22/2022	8/28/2022	9/7/2022	920,944	3.50	10.00	13.50	1.87%	0.25
Social Security/ Medicare	8/29/2022	9/4/2022	9/14/2022	879,365	3.50	10.00	13.50	1.79%	0.24
Social Security/ Medicare	9/5/2022	9/11/2022	9/21/2022	900,511	3.50	10.00	13.50	1.83%	0.25
Social Security/ Medicare	9/12/2022	9/18/2022	9/28/2022	918,455	3.50	10.00	13.50	1.87%	0.25
Social Security/ Medicare	9/19/2022	9/25/2022	10/5/2022	891,273	3.50	10.00	13.50	1.81%	0.24
Social Security/ Medicare	9/26/2022	10/2/2022	10/12/2022	883,506	3.50	10.00	13.50	1.80%	0.24
Social Security/ Medicare	10/3/2022	10/9/2022	10/19/2022	906,689	3.50	10.00	13.50	1.84%	0.25
Social Security/ Medicare	10/10/2022	10/16/2022	10/26/2022	875,464	3.50	10.00	13.50	1.78%	0.24
Social Security/ Medicare	10/17/2022	10/23/2022	11/2/2022	877,882	3.50	10.00	13.50	1.79%	0.24
Social Security/ Medicare	10/24/2022	10/30/2022	11/9/2022	857,145	3.50	10.00	13.50	1.74%	0.24
Social Security/ Medicare	10/31/2022	11/6/2022	11/16/2022	822,109	3.50	10.00	13.50	1.67%	0.23
Social Security/ Medicare	11/7/2022	11/13/2022	11/23/2022	806,941	3.50	10.00	13.50	1.64%	0.22
Social Security/ Medicare	11/14/2022	11/20/2022	11/30/2022	843,477	3.50	10.00	13.50	1.72%	0.23
Social Security/ Medicare	11/21/2022	11/27/2022	12/7/2022	738,030	3.50	10.00	13.50	1.50%	0.20
Social Security/ Medicare	11/28/2022	12/4/2022	12/14/2022	765,445	3.50	10.00	13.50	1.56%	0.21
Social Security/ Medicare	12/5/2022	12/11/2022	12/21/2022	746,835	3.50	10.00	13.50	1.52%	0.21
Social Security/ Medicare	12/12/2022	12/18/2022	12/28/2022	725,370	3.50	10.00	13.50	1.48%	0.20
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	153,546	45.00	29.00	74.00	0.31%	0.23
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	145,500	45.00	29.00	74.00	0.30%	0.22
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	148,381	45.00	29.00	74.00	0.30%	0.22

FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	121,423	45.00	29.00	74.00	0.25%	0.18
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	117,358	45.00	29.00	74.00	0.24%	0.18
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	107,919	45.00	29.00	74.00	0.22%	0.16
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	93,878	45.00	29.00	74.00	0.19%	0.14
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	96,385	45.00	29.00	74.00	0.20%	0.15
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	94,737	45.00	29.00	74.00	0.19%	0.14
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	92,355	45.00	29.00	74.00	0.19%	0.14
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	87,955	45.00	29.00	74.00	0.18%	0.13
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	82,723	45.00	29.00	74.00	0.17%	0.12
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	75,878	45.00	29.00	74.00	0.15%	0.11
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	66,962	45.50	29.00	74.50	0.14%	0.10
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	59,538	45.50	29.00	74.50	0.12%	0.09
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	50,712	45.50	29.00	74.50	0.10%	0.08
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	43,196	45.50	29.00	74.50	0.09%	0.07
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	37,743	45.50	29.00	74.50	0.08%	0.06
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	31,236	45.50	29.00	74.50	0.06%	0.05
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	28,569	45.50	29.00	74.50	0.06%	0.04
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	26,124	45.50	29.00	74.50	0.05%	0.04
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	23,243	45.50	29.00	74.50	0.05%	0.04
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	21,342	45.50	29.00	74.50	0.04%	0.03
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	19,258	45.50	29.00	74.50	0.04%	0.03
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	17,697	45.50	29.00	74.50	0.04%	0.03
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	16,192	45.50	29.00	74.50	0.03%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	14,338	46.00	31.00	77.00	0.03%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	12,512	46.00	31.00	77.00	0.03%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	11,877	46.00	31.00	77.00	0.02%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	10,930	46.00	31.00	77.00	0.02%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	10,149	46.00	31.00	77.00	0.02%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	9,602	46.00	31.00	77.00	0.02%	0.02
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	9,357	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	8,861	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	8,789	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	8,365	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	8,327	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	7,645	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	7,749	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,858	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	7,032	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	7,179	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,537	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,605	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,309	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,111	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	5,964	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	6,008	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	5,138	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	5,112	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	4,749	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	4,536	46.00	31.00	77.00	0.01%	0.01
				$ 49,146,375					16.06

Bi-Weekly Payroll	Pay Period Beginning	Pay Period End	Paid On	Net Pay	Midpoint of Pay Period	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Social Security/ Medicare	9/20/2021	10/3/2021	10/13/2021	$ 546,273	7.00	10.00	17.00	2.27%	0.39
Social Security/ Medicare	10/4/2021	10/17/2021	10/27/2021	523,893	7.00	10.00	17.00	2.17%	0.37
Social Security/ Medicare	10/18/2021	10/31/2021	11/10/2021	507,355	7.00	10.00	17.00	2.11%	0.36
Social Security/ Medicare	11/1/2021	11/14/2021	11/24/2021	478,511	7.00	10.00	17.00	1.99%	0.34
Social Security/ Medicare	11/15/2021	11/28/2021	12/8/2021	456,421	7.00	10.00	17.00	1.89%	0.32
Social Security/ Medicare	11/29/2021	12/12/2021	12/22/2021	498,358	7.00	10.00	17.00	2.07%	0.35
Social Security/ Medicare	12/13/2021	12/26/2021	1/5/2022	705,974	7.00	10.00	17.00	2.93%	0.50
Social Security/ Medicare	12/27/2021	1/9/2022	1/19/2022	731,773	7.00	10.00	17.00	3.04%	0.52
Social Security/ Medicare	1/10/2022	1/23/2022	2/2/2022	746,456	7.00	10.00	17.00	3.10%	0.53
Social Security/ Medicare	1/24/2022	2/6/2022	2/16/2022	758,710	7.00	10.00	17.00	3.15%	0.54
Social Security/ Medicare	2/7/2022	2/20/2022	3/2/2022	4,169,072	7.00	10.00	17.00	17.30%	2.94
Social Security/ Medicare	2/21/2022	3/6/2022	3/16/2022	760,457	7.00	10.00	17.00	3.16%	0.54
Social Security/ Medicare	3/7/2022	3/20/2022	3/30/2022	716,643	7.00	10.00	17.00	2.97%	0.51
Social Security/ Medicare	3/21/2022	4/3/2022	4/13/2022	737,423	7.00	10.00	17.00	3.06%	0.52
Social Security/ Medicare	4/4/2022	4/17/2022	4/27/2022	896,194	7.00	10.00	17.00	3.72%	0.63
Social Security/ Medicare	4/18/2022	5/1/2022	5/11/2022	714,570	7.00	10.00	17.00	2.96%	0.50
Social Security/ Medicare	5/2/2022	5/15/2022	5/25/2022	703,140	7.00	10.00	17.00	2.92%	0.50
Social Security/ Medicare	5/16/2022	5/29/2022	6/8/2022	693,435	7.00	10.00	17.00	2.88%	0.49
Social Security/ Medicare	5/30/2022	6/12/2022	6/22/2022	687,598	7.00	10.00	17.00	2.85%	0.49
Social Security/ Medicare	6/13/2022	6/26/2022	7/6/2022	675,316	7.00	10.00	17.00	2.80%	0.48
Social Security/ Medicare	6/27/2022	7/10/2022	7/20/2022	648,391	7.00	10.00	17.00	2.69%	0.46
Social Security/ Medicare	7/11/2022	7/24/2022	8/3/2022	658,910	7.00	10.00	17.00	2.73%	0.46
Social Security/ Medicare	7/25/2022	8/7/2022	8/17/2022	625,410	7.00	10.00	17.00	2.59%	0.44
Social Security/ Medicare	8/8/2022	8/21/2022	8/31/2022	606,437	7.00	10.00	17.00	2.52%	0.43
Social Security/ Medicare	8/22/2022	9/4/2022	9/14/2022	573,117	7.00	10.00	17.00	2.38%	0.40
Social Security/ Medicare	9/5/2022	9/18/2022	9/28/2022	565,298	7.00	10.00	17.00	2.35%	0.40
Social Security/ Medicare	9/19/2022	10/2/2022	10/12/2022	537,396	7.00	10.00	17.00	2.23%	0.38
Social Security/ Medicare	10/3/2022	10/16/2022	10/26/2022	525,439	7.00	10.00	17.00	2.18%	0.37
Social Security/ Medicare	10/17/2022	10/30/2022	11/9/2022	498,830	7.00	10.00	17.00	2.07%	0.35
Social Security/ Medicare	10/31/2022	11/13/2022	11/23/2022	466,556	7.00	10.00	17.00	1.94%	0.33
Social Security/ Medicare	11/14/2022	11/27/2022	12/7/2022	450,393	7.00	10.00	17.00	1.87%	0.32
Social Security/ Medicare	11/28/2022	12/11/2022	12/21/2022	478,687	7.00	10.00	17.00	1.99%	0.34
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	130,160	45.00	29.00	74.00	0.54%	0.40
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	102,312	45.00	29.00	74.00	0.42%	0.31
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	83,393	45.00	29.00	74.00	0.35%	0.26
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	79,327	45.00	29.00	74.00	0.33%	0.24
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	247,493	45.00	29.00	74.00	1.03%	0.76
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	21,634	45.00	29.00	74.00	0.09%	0.07
FUTA/ NJUC	1/1/2022	3/31/2022	4/29/2022	16,374	45.00	29.00	74.00	0.07%	0.05
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	12,131	45.50	29.00	74.50	0.05%	0.04
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	9,601	45.50	29.00	74.50	0.04%	0.03
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	6,540	45.50	29.00	74.50	0.03%	0.02
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	4,593	45.50	29.00	74.50	0.02%	0.01
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	3,734	45.50	29.00	74.50	0.02%	0.01
FUTA/ NJUC	4/1/2022	6/30/2022	7/29/2022	3,964	45.50	29.00	74.50	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	4,445	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	4,110	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	4,234	46.00	31.00	77.00	0.02%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	3,615	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	3,026	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	2,680	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	7/1/2022	9/30/2022	10/31/2022	2,871	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	2,466	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	2,370	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	2,103	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	2,022	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	1,899	46.00	31.00	77.00	0.01%	0.01
FUTA/ NJUC	10/1/2022	12/31/2022	1/31/2023	1,542	46.00	31.00	77.00	0.01%	0.00
				$ 24,101,075					18.80

	Amount	Expense Lead	Weighting	Weighted Lead
Weekly	49,146,375	16.06	67.1%	10.78
Bi-Weekly	24,101,075	18.80	32.9%	6.19
Weighted Lead for Weekly and Bi-Weekly Payroll	73,247,449			16.96 days

Real Estate Tax	Amount Paid	Period Beginning	Period End	Payment Date	Service Lead	Payment Lead Time	Check Float	Total Lead	Weighting Factor	Weighted Lead
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(L)
NJ-Audubon Borough	$ 29,128	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.16%	(0.18)
NJ-Audubon Borough	29,128	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.16%	(0.03)
NJ-Audubon Borough	31,656	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.18%	0.00
NJ-Audubon Borough	31,656	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.18%	(0.16)
NJ-Bayonne City	117,558	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.66%	(0.01)
NJ-Bayonne City	114,940	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.64%	(0.10)
NJ-Bayonne City	114,420	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.64%	(0.70)
NJ-Bayonne City	114,420	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.64%	(0.12)
NJ-Belleville Township	16,304	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.09%	(0.01)
NJ-Belleville Township	15,829	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.09%	(0.10)
NJ-Belleville Township	16,288	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.09%	(0.02)
NJ-Belleville Township	15,829	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.09%	(0.02)
NJ-Bellmawr Borough	15,531	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.09%	(0.10)
NJ-Bellmawr Borough	15,531	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.09%	(0.02)
NJ-Bellmawr Borough	14,933	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.08%	0.01
NJ-Bellmawr Borough	14,933	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.08%	(0.06)
NJ-Bergenfield Borough	5,331	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.03%	(0.00)
NJ-Bergenfield Borough	5,191	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.03%	(0.03)
NJ-Bergenfield Borough	5,191	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.03%	(0.01)
NJ-Bergenfield Borough	5,269	10/1/2022	12/31/2022	9/28/2022	46.00	-93.5	12.23	(35.28)	0.03%	(0.01)
NJ-Bernards Township	516	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.00%	(0.00)
NJ-Bernards Township	516	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.00%	(0.00)
NJ-Bernards Township	569	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.00%	(0.00)
NJ-Bernards Township	569	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.00%	(0.00)
NJ-Bloomfield Township	21,104	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.12%	(0.02)
NJ-Bloomfield Township	20,975	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.12%	(0.02)
NJ-Bloomfield Township	20,279	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.11%	(0.02)
NJ-Bloomfield Township	20,279	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.11%	(0.12)
NJ-Bogota Borough	1,276	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4		(27.41)	0.01%	(0.00)
NJ-Bogota Borough	1,259	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5		(26.55)	0.01%	(0.00)
NJ-Bogota Borough	1,217	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3		(31.34)	0.01%	(0.00)
NJ-Bogota Borough	1,217	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3		(121.83)	0.01%	(0.01)
NJ-Bordentown City	2,053	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Bordentown City	2,053	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-Bordentown City	2,103	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.01%	(0.00)
NJ-Bordentown City	2,103	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.01%	(0.01)
NJ-Bordentown Township	14,635	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.08%	(0.02)
NJ-Bordentown Township	14,635	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.08%	(0.09)
NJ-Bordentown Township	13,257	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.07%	0.02
NJ-Bordentown Township	13,257	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.07%	(0.05)
NJ-Branchburg Township	50,621	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.28%	(0.00)
NJ-Branchburg Township	50,621	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.28%	(0.26)
NJ-Branchburg Township	58,669	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.33%	(0.06)
NJ-Branchburg Township	58,669	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.33%	(0.36)
NJ-Bridgewater Township	46,142	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.26%	(0.04)
NJ-Bridgewater Township	46,657	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.26%	(0.04)
NJ-Bridgewater Township	46,219	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.26%	(0.05)
NJ-Bridgewater Township	46,219	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.26%	(0.28)
NJ-Burlington City	477	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.00%	(0.00)
NJ-Burlington City	477	4/1/2022	6/30/2022	3/23/2022	45.50	-98.6		(53.11)	0.00%	(0.00)
NJ-Burlington City	491	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4		3.55	0.00%	0.00

NJ-Burlington City	491	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4		(88.45)	0.00%	(0.00)
NJ-Burlington Township	13,231	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.07%	0.01
NJ-Burlington Township	13,231	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.07%	(0.06)
NJ-Burlington Township	13,501	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.08%	(0.01)
NJ-Burlington Township	13,501	4/1/2022	6/30/2022	3/14/2022	45.50	-107.5	12.23	(49.80)	0.08%	(0.04)
NJ-Caldwell Borough	6,654	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.04%	(0.01)
NJ-Caldwell Borough	6,326	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.04%	(0.01)
NJ-Caldwell Borough	5,896	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.03%	(0.01)
NJ-Caldwell Borough	5,896	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.03%	(0.04)
NJ-Camden City	17,923	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.10%	0.02
NJ-Camden City	17,923	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.10%	(0.08)
NJ-Camden City	13,434	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.08%	(0.01)
NJ-Camden City	13,434	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.08%	(0.08)
NJ-Carlstadt Borough	2,275	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Carlstadt Borough	3,907	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.02%	(0.00)
NJ-Carlstadt Borough	3,316	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.02%	(0.00)
NJ-Carlstadt Borough	3,316	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Carteret Borough	24,166	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.14%	(0.02)
NJ-Carteret Borough	24,166	10/1/2022	12/31/2022	7/18/2022	46.00	-165.4	12.23	(107.19)	0.14%	(0.15)
NJ-Carteret Borough	32,063	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.18%	(0.03)
NJ-Carteret Borough	32,063	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.18%	(0.20)
NJ-Cedar Grove Township	35,484	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.20%	(0.03)
NJ-Cedar Grove Township	36,035	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.20%	(0.05)
NJ-Cedar Grove Township	34,905	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.20%	(0.04)
NJ-Cedar Grove Township	34,905	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.20%	(0.21)
NJ-Chatham Borough	57	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.00%	0.00
NJ-Chatham Borough	57	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.00%	(0.00)
NJ-Chatham Borough	55	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.00%	(0.00)
NJ-Chatham Borough	55	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.00%	(0.00)
NJ-Chatham Township	3,010	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.02%	(0.00)
NJ-Chatham Township	2,920	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-Chatham Township	2,920	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.02%	(0.02)
NJ-Chatham Township	2,920	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.02%	(0.00)
NJ-Cherry Hill Township	14,879	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.08%	(0.00)
NJ-Cherry Hill Township	14,879	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.08%	(0.08)
NJ-Cherry Hill Township	14,771	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.08%	0.01
NJ-Cherry Hill Township	14,771	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.08%	(0.06)
NJ-Chesterfield Township	2,146	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4		(27.41)	0.01%	(0.00)
NJ-Chesterfield Township	2,073	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3		(23.30)	0.01%	(0.00)
NJ-Chesterfield Township	2,073	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3		(113.80)	0.01%	(0.01)
NJ-Chesterfield Township	2,135	10/1/2022	12/31/2022	9/28/2022	46.00	-93.5		(47.51)	0.01%	(0.01)
NJ-Cinnaminson Township	6,145	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.03%	(0.00)
NJ-Cinnaminson Township	6,145	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.03%	(0.03)
NJ-Cinnaminson Township	6,243	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.03%	0.01
NJ-Cinnaminson Township	6,243	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.03%	(0.02)
NJ-Orange City	15,213	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.09%	(0.01)
NJ-Orange City	14,343	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.08%	(0.00)
NJ-Orange City	15,366	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.09%	(0.01)
NJ-Orange City	14,343	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.08%	(0.08)
NJ-Clark Township	1,044	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.01%	(0.00)
NJ-Clark Township	1,044	10/1/2022	12/31/2022	7/18/2022	46.00	-165.4	12.23	(107.19)	0.01%	(0.01)
NJ-Clark Township	3,067	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Clark Township	3,067	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.02%	(0.00)
NJ-Cliffside Park Borough	1,692	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Cliffside Park Borough	1,636	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)

NJ-Cliffside Park Borough	1,636	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.01%	(0.01)
NJ-Cliffside Park Borough	1,705	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.01%	(0.00)
										-
NJ-Clifton City	290,685	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5		(27.46)	1.63%	(0.45)
NJ-Clifton City	254,034	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4		(27.42)	1.42%	(0.39)
NJ-Clifton City	250,828	1/1/2022	3/31/2022	1/28/2022	45.00	-61.3		(16.30)	1.41%	(0.23)
NJ-Clifton City	250,827	4/1/2022	6/30/2022	1/28/2022	45.50	-152.3		(106.80)	1.41%	(1.50)
NJ-Clifton City	-			10/21/2022				-	0.00%	-
NJ-Collingswood Borough	1,147	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Collingswood Borough	1,147	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.01%	(0.01)
NJ-Collingswood Borough	1,182	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.01%	0.00
NJ-Collingswood Borough	1,182	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.01%	(0.01)
NJ-Cranford Township	39,716	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.22%	(0.08)
NJ-Cranford Township	39,692	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.22%	(0.05)
NJ-Cranford Township	39,359	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.22%	(0.24)
NJ-Cranford Township	39,359	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.22%	(0.04)
NJ-Deptford Township	4,326	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-Deptford Township	4,326	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6	12.23	(95.87)	0.02%	(0.02)
NJ-Deptford Township	4,450	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.02%	0.00
NJ-Deptford Township	4,450	10/1/2022	12/31/2022	8/9/2022	46.00	-143.3	12.23	(85.04)	0.02%	(0.02)
NJ-Dumont Borough	5,052	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-Dumont Borough	5,021	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.03%	(0.03)
NJ-Dumont Borough	5,089	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.03%	(0.01)
NJ-Dumont Borough	5,021	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.03%	(0.01)
NJ-East Brunswick Township	4,867	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-East Brunswick Township	4,361	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.03)
NJ-East Brunswick Township	4,357	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.02%	(0.01)
NJ-East Brunswick Township	4,361	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.02%	(0.00)
NJ-East Orange City	44,419	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.25%	(0.27)
NJ-East Orange City	44,419	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.25%	(0.05)
NJ-East Orange City	36,441	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.20%	0.05
NJ-East Orange City	36,441	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.20%	(0.14)
NJ-East Rutherford Borough	56,153	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.31%	(0.05)
NJ-East Rutherford Borough	57,998	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.32%	(0.36)
NJ-East Rutherford Borough	55,893	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.31%	(0.07)
NJ-East Rutherford Borough	57,998	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.32%	(0.06)
NJ-Edgewater Borough	225	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.00%	(0.00)
NJ-Edgewater Borough	252	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.00%	(0.00)
NJ-Edgewater Borough	263	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.00%	(0.00)
NJ-Edgewater Borough	225	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.00%	(0.00)
NJ-Edison Township	295,788	4/1/2022	6/30/2022	3/23/2022	45.50	-98.6		(53.11)	1.66%	(0.88)
NJ-Edison Township	295,788	1/1/2022	3/31/2022	1/28/2022	45.00	-61.3		(16.30)	1.66%	(0.27)
NJ-Edison Township	297,811	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6		(11.63)	1.67%	(0.19)
NJ-Edison Township	297,811	10/1/2022	12/31/2022	10/21/2022	46.00	-70.6		(24.64)	1.67%	(0.41)
NJ-Edison Township	31,142	10/1/2022	12/31/2022	12/13/2022	46.00	-17.5		28.50	0.17%	0.05
NJ-Elizabeth City	212,109	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	1.19%	(0.21)
NJ-Elizabeth City	212,109	4/1/2022	6/30/2022	1/27/2022	45.50	-153.6		(108.10)	1.19%	(1.28)
NJ-Elizabeth City	203,654	7/1/2022	9/30/2022	8/2/2022	46.00	-58.7		(12.68)	1.14%	(0.14)
NJ-Elizabeth City	203,654	10/1/2022	12/31/2022	8/2/2022	46.00	-150.7		(104.68)	1.14%	(1.19)
NJ-Elmwood Park Borough	2,875	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.02%	(0.02)
NJ-Elmwood Park Borough	2,818	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.02%	(0.00)
NJ-Elmwood Park Borough	2,879	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.02%	(0.00)
NJ-Elmwood Park Borough	2,875	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.02%	(0.00)
NJ-Elmwood Park Borough	3,886	10/1/2022	12/31/2022	11/16/2022	46.00	-44.6	12.23	13.63	0.02%	0.00
NJ-Emerson Borough	1,403	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.01%	(0.00)
NJ-Emerson Borough	1,346	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.01%	(0.01)
NJ-Emerson Borough	1,397	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.01%	(0.00)

NJ-Emerson Borough	1,346	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.01%	(0.00)
NJ-Englewood City	7,650	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.04%	(0.04)
NJ-Englewood City	8,047	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.05%	(0.01)
NJ-Englewood City	7,877	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.04%	(0.01)
NJ-Englewood City	7,650	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.04%	(0.00)
NJ-Englewood Cliffs Borough	3,878	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.02%	(0.02)
NJ-Englewood Cliffs Borough	4,015	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.02%	(0.00)
NJ-Englewood Cliffs Borough	3,726	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.02%	(0.00)
NJ-Englewood Cliffs Borough	3,878	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.02%	(0.00)
NJ-Evesham Township	20,927	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.12%	(0.02)
NJ-Evesham Township	20,031	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.11%	(0.12)
NJ-Evesham Township	21,061	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.12%	(0.03)
NJ-Evesham Township	20,031	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.11%	(0.02)
NJ-Ewing Township	8,070	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.05%	(0.05)
NJ-Ewing Township	8,070	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.05%	(0.01)
NJ-Ewing Township	8,475	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.05%	0.00
NJ-Ewing Township	8,475	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.05%	(0.04)
NJ-Fair Lawn Borough	44,140	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.25%	(0.04)
NJ-Fair Lawn Borough	44,605	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.25%	(0.27)
NJ-Fair Lawn Borough	44,912	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.25%	(0.06)
NJ-Fair Lawn Borough	44,605	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.25%	(0.05)
NJ-Fairview Borough	5,775	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.03%	(0.03)
NJ-Fairview Borough	5,320	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-Fairview Borough	5,301	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.03%	(0.00)
NJ-Fairview Borough	5,775	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.03%	(0.00)
NJ-Fanwood Borough	3,125	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Fanwood Borough	3,125	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.02%	(0.00)
NJ-Fanwood Borough	3,188	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.02%	0.00
NJ-Fanwood Borough	3,188	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.02%	(0.02)
NJ-Fort Lee Borough	5,200	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.03%	(0.00)
NJ-Fort Lee Borough	4,976	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.03%	(0.03)
NJ-Fort Lee Borough	4,976	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.03%	(0.01)
NJ-Fort Lee Borough	5,169	10/1/2022	12/31/2022	10/26/2022	46.00	-65.5	12.23	(7.23)	0.03%	(0.00)
NJ-Franklin Township-Somerset	89,874	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.50%	(0.09)
NJ-Franklin Township-Somerset	89,874	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4		(107.93)	0.50%	(0.54)
NJ-Franklin Township-Somerset	67,868	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4		3.55	0.38%	0.01
NJ-Franklin Township-Somerset	67,868	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4		(88.45)	0.38%	(0.34)
NJ-Garfield City	795	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.00%	(0.00)
NJ-Garfield City	777	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.00%	(0.00)
NJ-Garfield City	854	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.00%	(0.00)
NJ-Garfield City	777	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.11)	0.00%	(0.00)
NJ-Glen Rock Borough	13,899	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.08%	(0.01)
NJ-Glen Rock Borough	13,393	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5	12.23	(14.32)	0.08%	(0.01)
NJ-Glen Rock Borough	13,313	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.07%	(0.01)
NJ-Glen Rock Borough	13,313	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.07%	(0.08)
NJ-Gloucester City	23,206	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.13%	(0.02)
NJ-Gloucester City	23,206	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.13%	(0.14)
NJ-Gloucester City	23,674	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.13%	0.02
NJ-Gloucester City	23,674	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.13%	(0.10)
NJ-Gloucester Township	4,661	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.03%	(0.00)
NJ-Gloucester Township	4,661	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.03%	(0.03)
NJ-Gloucester Township	8,214	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.05%	0.01
NJ-Gloucester Township	8,214	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.05%	(0.04)
NJ-Green Brook Township	7,752	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.04%	(0.00)
NJ-Green Brook Township	7,780	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.04%	(0.02)

NJ-Green Brook Township	9,162	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.05%	(0.01)
NJ-Green Brook Township	9,162	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.05%	(0.06)
NJ-Greenwich Township-Gibbstown	6,591	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.04%	(0.01)
NJ-Greenwich Township-Gibbstown	6,591	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.04%	(0.04)
NJ-Greenwich Township-Gibbstown	581	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.00%	0.00
NJ-Greenwich Township-Gibbstown	581	10/1/2022	12/31/2022	8/9/2022	46.00	-143.3	12.23	(85.04)	0.00%	(0.00)
NJ-Hackensack City	95,538	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.54%	(0.08)
NJ-Hackensack City	155,778	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.87%	(0.17)
NJ-Hackensack City	155,778	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.87%	(0.96)
NJ-Hackensack City	94,464	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.53%	(0.12)
NJ-Haddon Heights Borough	3,261	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.02%	(0.00)
NJ-Haddon Heights Borough	3,261	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Haddon Heights Borough	3,280	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.02%	0.00
NJ-Haddon Heights Borough	3,280	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.02%	(0.01)
NJ-Haddon Township	1,403	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.01%	(0.00)
NJ-Haddon Township	1,403	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.01%	(0.01)
NJ-Haddon Township	1,382	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Haddon Township	1,382	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-Haledon Borough	1,711	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Haledon Borough	1,847	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Haledon Borough	1,777	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Haledon Borough	1,712	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Hamilton Township	98,812	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.55%	0.04
NJ-Hamilton Township	98,812	10/1/2022	12/31/2022	8/9/2022	46.00	-143.3	12.23	(85.04)	0.55%	(0.47)
NJ-Hamilton Township	94,089	1/1/2022	3/31/2022	1/28/2022	45.00	-61.3	12.23	(4.08)	0.53%	(0.02)
NJ-Hamilton Township	96,334	4/1/2022	6/30/2022	1/28/2022	45.50	-152.3	12.23	(94.58)	0.54%	(0.51)
NJ-Hamilton Township	12,650	10/1/2022	12/31/2022	11/7/2022	46.00	-53.4	12.23	4.82	0.07%	0.00
NJ-Harding Township	3,383	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.02%	(0.02)
NJ-Harding Township	3,505	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.02%	(0.00)
NJ-Harding Township	3,505	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.02%	(0.02)
NJ-Harding Township	3,383	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.02%	(0.00)
NJ-Harrison Town	258,350	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	1.45%	(1.47)
NJ-Harrison Town	258,350	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	1.45%	(0.16)
NJ-Harrison Town	222,190	7/1/2022	9/30/2022	8/30/2022	46.00	-30.7	12.23	27.58	1.24%	0.34
NJ-Harrison Town	257,229	10/1/2022	12/31/2022	8/30/2022	46.00	-122.7	12.23	(64.42)	1.44%	(0.93)
NJ-Hawthorne Borough	8,919	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.05%	(0.05)
NJ-Hawthorne Borough	8,919	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.05%	(0.01)
NJ-Hawthorne Borough	9,277	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.05%	0.01
NJ-Hawthorne Borough	9,276	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.05%	(0.04)
NJ-Highland Park Borough	217	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.00%	(0.00)
NJ-Highland Park Borough	218	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.00%	(0.00)
NJ-Highland Park Borough	218	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.00%	(0.00)
NJ-Highland Park Borough	217	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.00%	(0.00)
NJ-Hillsborough Township	5,428	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.03%	(0.03)
NJ-Hillsborough Township	5,317	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.03%	(0.00)
NJ-Hillsborough Township	4,476	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-Hillsborough Township	5,428	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.03%	(0.00)
NJ-Hillsdale Borough	9,269	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.05%	(0.05)
NJ-Hillsdale Borough	9,413	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.05%	(0.01)
NJ-Hillsdale Borough	9,269	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.05%	(0.01)
NJ-Hillsdale Borough	9,538	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.05%	(0.01)
NJ-Hillside Township	6,268	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.04%	(0.04)
NJ-Hillside Township	6,341	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.04%	(0.01)
NJ-Hillside Township	6,268	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.04%	(0.00)
NJ-Hillside Township	6,361	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.04%	(0.01)

NJ-Hoboken City	56,433	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.32%	(0.02)
NJ-Hoboken City	55,106	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.31%	(0.30)
NJ-Hoboken City	47,551	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.27%	0.04
NJ-Hoboken City	47,551	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.27%	(0.20)
NJ-Hopewell Township-Titusville	8,623	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.05%	(0.05)
NJ-Hopewell Township-Titusville	8,250	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.05%	(0.00)
NJ-Hopewell Township-Titusville	8,250	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.05%	(0.04)
NJ-Hopewell Township-Titusville	8,623	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.05%	(0.01)
NJ-Irvington Township	97,800	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.55%	(0.03)
NJ-Irvington Township	95,958	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.54%	(0.08)
NJ-Irvington Township	97,800	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.55%	(0.52)
NJ-Irvington Township	98,490	10/1/2022	12/31/2022	10/26/2022	46.00	-65.5	12.23	(7.23)	0.55%	(0.04)
NJ-Jersey City	201,763	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4		(27.41)	1.13%	(0.31)
NJ-Jersey City	148,863	1/1/2022	3/31/2022	1/28/2022	45.00	-61.3		(16.30)	0.83%	(0.14)
NJ-Jersey City	148,863	4/1/2022	6/30/2022	1/28/2022	45.50	-152.3		(106.80)	0.83%	(0.89)
NJ-Jersey City	286,774	10/1/2022	12/31/2022	11/7/2022	46.00	-53.4		(7.41)	1.61%	(0.12)
NJ-Kearny Town	17,633	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.10%	(0.01)
NJ-Kearny Town	12,422	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.07%	0.01
NJ-Kearny Town	12,422	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.07%	(0.05)
NJ-Kearny Town	12,288	4/1/2022	6/30/2022	3/14/2022	45.50	-107.5	12.23	(49.80)	0.07%	(0.03)
NJ-Kenilworth Borough	1,413	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Kenilworth Borough	1,476	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5	12.23	(14.32)	0.01%	(0.00)
NJ-Kenilworth Borough	1,413	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.01%	(0.01)
NJ-Kenilworth Borough	1,496	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Lawnside Borough	2,319	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Lawnside Borough	3,830	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.02%	(0.01)
NJ-Lawnside Borough	2,319	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.01%	(0.01)
NJ-Lawnside Borough	3,830	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.02%	0.01
NJ-Lawrence Township	79,170	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.44%	(0.45)
NJ-Lawrence Township	79,170	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.44%	(0.05)
NJ-Lawrence Township	78,437	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.44%	0.07
NJ-Lawrence Township	89,576	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.50%	(0.38)
NJ-Leonia Borough	8,803	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.05%	(0.05)
NJ-Leonia Borough	8,709	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.05%	(0.01)
NJ-Leonia Borough	8,803	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.05%	(0.01)
NJ-Leonia Borough	8,709	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.05%	(0.01)
NJ-Linden City	80,376	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.45%	(0.07)
NJ-Linden City	82,149	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.46%	(0.05)
NJ-Linden City	82,268	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.46%	(0.10)
NJ-Linden City	82,149	4/1/2022	6/30/2022	3/14/2022	45.50	-107.5	12.23	(49.80)	0.46%	(0.23)
NJ-Little Falls Township	5,210	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.03%	(0.03)
NJ-Little Falls Township	5,417	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-Little Falls Township	5,210	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.03%	(0.00)
NJ-Little Falls Township	5,482	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.03%	(0.00)
NJ-Little Ferry Borough	1,653	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Little Ferry Borough	1,357	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.01%	(0.00)
NJ-Little Ferry Borough	1,355	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Little Ferry Borough	1,653	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Livingston Township	6,860	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.04%	(0.00)
NJ-Livingston Township	6,582	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.04%	(0.00)
NJ-Livingston Township	6,519	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.04%	(0.01)
NJ-Livingston Township	109	1/1/2022	3/31/2022	4/8/2022	45.00	8.6	12.23	65.85	0.00%	0.00
NJ-Livingston Township	6,696	4/1/2022	6/30/2022	4/8/2022	45.50	-82.4	12.23	(24.65)	0.04%	(0.01)
NJ-Lodi Borough	1,446	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Lodi Borough	1,404	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Lodi Borough	1,446	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)

NJ-Lodi Borough	1,416	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.01%	(0.00)
NJ-Long Hill Township	1,886	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Long Hill Township	1,886	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Long Hill Township	1,646	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Long Hill Township	1,646	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-Lumberton Township	2,438	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Lumberton Township	2,438	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.01%	(0.01)
NJ-Lumberton Township	2,452	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Lumberton Township	2,452	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-Lyndhurst Township	4,560	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.03%	(0.03)
NJ-Lyndhurst Township	4,560	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.03%	(0.00)
NJ-Lyndhurst Township	4,950	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.03%	(0.01)
NJ-Lyndhurst Township	4,962	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.03%	(0.01)
NJ-Mahwah Township	332	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.00%	(0.00)
NJ-Mahwah Township	329	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.00%	(0.00)
NJ-Mahwah Township	332	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.00%	(0.00)
NJ-Mahwah Township	348	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.00%	(0.00)
NJ-Maple Shade Township	18,844	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.11%	(0.11)
NJ-Maple Shade Township	18,844	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.11%	(0.01)
NJ-Maple Shade Township	11,053	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.06%	0.01
NJ-Maple Shade Township	11,053	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.06%	(0.04)
NJ-Maywood Borough	26,229	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.15%	(0.15)
NJ-Maywood Borough	24,275	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.14%	(0.02)
NJ-Maywood Borough	26,229	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.15%	(0.02)
NJ-Maywood Borough	24,187	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.14%	(0.02)
NJ-Medford Township	7,093	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.04%	(0.01)
NJ-Medford Township	7,093	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4		(107.93)	0.04%	(0.04)
NJ-Medford Township	7,172	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4		3.55	0.04%	0.00
NJ-Medford Township	7,172	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4		(88.45)	0.04%	(0.04)
NJ-Middlesex Borough	3,482	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.02%	(0.02)
NJ-Middlesex Borough	3,664	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.02%	(0.00)
NJ-Middlesex Borough	3,664	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.02%	(0.02)
NJ-Middlesex Borough	3,482	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.02%	(0.00)
NJ-Milltown Borough	1,454	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Milltown Borough	1,454	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Milltown Borough	1,516	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.01%	0.00
NJ-Milltown Borough	1,516	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-Montgomery Township	9,569	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.05%	(0.05)
NJ-Montgomery Township	9,569	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.05%	(0.01)
NJ-Montgomery Township	9,737	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.05%	0.00
NJ-Montgomery Township	9,737	10/1/2022	12/31/2022	8/9/2022	46.00	-143.3	12.23	(85.04)	0.05%	(0.05)
NJ-Moorestown Township	47,694	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.27%	(0.27)
NJ-Moorestown Township	47,694	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.27%	(0.03)
NJ-Moorestown Township	48,972	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.27%	0.02
NJ-Moorestown Township	48,972	10/1/2022	12/31/2022	8/9/2022	46.00	-143.3	12.23	(85.04)	0.27%	(0.23)
NJ-Morris Township	2,142	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Morris Township	2,229	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Morris Township	2,142	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Morris Township	2,238	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.01%	(0.00)
NJ-Mount Holly Township	287	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.00%	(0.00)
NJ-Mount Holly Township	287	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.00%	(0.00)
NJ-Mount Holly Township	293	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.00%	(0.00)
NJ-Mount Holly Township	300	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.00%	(0.00)
NJ-Mount Laurel Township	3,472	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.02%	(0.00)
NJ-Mount Laurel Township	3,472	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.02%	(0.02)

NJ-Mount Laurel Township	3,606	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.02%	0.00
NJ-Mount Laurel Township	3,606	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.02%	(0.02)
NJ-Mountainside Borough	1,803	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.01%	(0.00)
NJ-Mountainside Borough	1,803	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.01%	(0.01)
NJ-Mountainside Borough	8	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.00%	(0.00)
NJ-Mountainside Borough	1,866	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.01%	0.00
NJ-Mountainside Borough	1,862	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.01%	(0.01)
NJ-New Brunswick City	19,247	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.11%	(0.01)
NJ-New Brunswick City	19,625	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.11%	(0.11)
NJ-New Brunswick City	19,291	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.11%	(0.00)
NJ-New Brunswick City	19,322	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.11%	(0.02)
NJ-New Milford Borough	31,823	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.18%	(0.02)
NJ-New Milford Borough	31,823	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.18%	(0.18)
NJ-New Milford Borough	32,991	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.18%	(0.03)
NJ-New Milford Borough	33,270	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.19%	(0.03)
NJ-Newark City	167,309	1/1/2022	3/31/2022	1/28/2022	45.00	-61.3		(16.30)	0.94%	(0.15)
NJ-Newark City	167,309	4/1/2022	6/30/2022	3/28/2022	45.50	-93.3		(47.85)	0.94%	(0.45)
NJ-Newark City	152,047	7/1/2022	9/30/2022	10/21/2022	46.00	21.4		67.36	0.85%	0.57
NJ-Newark City	157,589	10/1/2022	12/31/2022	10/21/2022	46.00	-70.6		(24.64)	0.88%	(0.22)
NJ-North Bergen Township	139,840	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.78%	(0.09)
NJ-North Bergen Township	139,840	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.78%	(0.80)
NJ-North Bergen Township	-	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.00%	-
NJ-North Bergen Township	1,343	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.01%	(0.01)
NJ-North Brunswick Township	77,461	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.43%	(0.01)
NJ-North Brunswick Township	77,461	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.43%	(0.41)
NJ-North Brunswick Township	38,451	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.22%	(0.01)
NJ-North Brunswick Township	38,451	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.22%	(0.21)
NJ-Nutley Township	12,767	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.07%	(0.00)
NJ-Nutley Township	12,767	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.07%	(0.07)
NJ-Nutley Township	12,900	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.07%	0.02
NJ-Nutley Township	12,900	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.07%	(0.05)
NJ-Oakland Borough	46,050	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.26%	(0.01)
NJ-Oakland Borough	58,572	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.33%	(0.12)
NJ-Oakland Borough	57,863	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.32%	(0.05)
NJ-Oakland Borough	46,050	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.26%	(0.25)
NJ-Oradell Borough	44,726	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.25%	(0.04)
NJ-Oradell Borough	41,582	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.23%	(0.01)
NJ-Oradell Borough	46,158	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.26%	(0.06)
NJ-Oradell Borough	41,582	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.23%	(0.22)
NJ-Paramus Borough	14,304	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.08%	(0.01)
NJ-Paramus Borough	14,991	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.08%	(0.00)
NJ-Paramus Borough	14,493	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.08%	(0.02)
NJ-Paramus Borough	14,991	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.08%	(0.08)
NJ-Parsippany-Troy Hills Township	4,740	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.03%	(0.00)
NJ-Parsippany-Troy Hills Township	4,356	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-Parsippany-Troy Hills Township	4,729	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.03%	(0.01)
NJ-Parsippany-Troy Hills Township	4,356	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.02%	(0.02)
NJ-Passaic City	10,966	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.06%	(0.01)
NJ-Passaic City	10,126	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.06%	(0.00)
NJ-Passaic City	10,621	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.06%	(0.01)
NJ-Passaic City	10,126	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.06%	(0.05)
NJ-Paterson City	97,821	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.55%	(0.03)
NJ-Paterson City	1,762	10/1/2022	12/31/2022	7/11/2022	46.00	-172.6	12.23	(114.35)	0.01%	(0.01)
NJ-Paterson City	1,762	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.01%	(0.00)
NJ-Paterson City	3,591	4/1/2022	6/30/2022	7/18/2022	45.50	18.6	12.23	76.31	0.02%	0.02
NJ-Paterson City	100,841	7/1/2022	9/30/2022	9/26/2022	46.00	-3.4	12.23	54.80	0.56%	0.31

NJ-Paterson City	97,821	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.55%	(0.52)
NJ-Paterson City	101,699	10/1/2022	12/31/2022	11/7/2022	46.00	-53.4	12.23	4.82	0.57%	0.03
NJ-Paterson City	-	1/1/2022	3/31/2022	8/1/2022	45.00	123.4	12.23	180.62	0.00%	-
NJ-Paulsboro Borough	8,506	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.05%	(0.00)
NJ-Paulsboro Borough	8,506	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.05%	(0.05)
NJ-Pemberton Township	361	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.00%	(0.00)
NJ-Pemberton Township	361	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.00%	(0.00)
NJ-Pemberton Township	391	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.00%	0.00
NJ-Pemberton Township	391	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.00%	(0.00)
NJ-Pennsauken Township	55,642	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.31%	(0.02)
NJ-Pennsauken Township	55,642	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.70)	0.31%	(0.30)
NJ-Pennsauken Township	58,253	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.33%	0.05
NJ-Pennsauken Township	58,253	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.33%	(0.25)
NJ-Perth Amboy City	6,358	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3	12.23	(11.07)	0.04%	(0.00)
NJ-Perth Amboy City	6,358	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3	12.23	(101.57)	0.04%	(0.04)
NJ-Perth Amboy City	6,341	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.04%	0.00
NJ-Perth Amboy City	6,341	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.04%	(0.03)
NJ-Piscataway Township	31,367	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.18%	(0.03)
NJ-Piscataway Township	31,367	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4		(107.92)	0.18%	(0.19)
NJ-Piscataway Township	36,500	7/1/2022	9/30/2022	8/2/2022	46.00	-58.7		(12.68)	0.20%	(0.03)
NJ-Piscataway Township	36,500	10/1/2022	12/31/2022	8/2/2022	46.00	-150.7		(104.68)	0.20%	(0.21)
NJ-Plainfield City	32,194	1/1/2022	3/31/2022	2/8/2022	45.00	-50.4	12.23	6.83	0.18%	0.01
NJ-Plainfield City	157	1/1/2022	3/31/2022	3/14/2022	45.00	-16.5	12.23	40.70	0.00%	0.00
NJ-Plainfield City	32,351	4/1/2022	6/30/2022	3/14/2022	45.50	-107.5	12.23	(49.80)	0.18%	(0.09)
NJ-Plainfield City	32,922	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.18%	0.04
NJ-Plainfield City	32,919	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.18%	(0.13)
NJ-Princeton	990	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Princeton	10,977	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.06%	(0.00)
NJ-Princeton	10,977	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.06%	(0.06)
NJ-Princeton	10,913	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.06%	(0.02)
NJ-Princeton	10,913	7/1/2022	9/30/2022	9/26/2022	46.00	-3.4	12.23	54.80	0.06%	0.03
NJ-Rahway City	4,517	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.03%	(0.00)
NJ-Rahway City	4,517	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.03%	(0.02)
NJ-Rahway City	4,608	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.03%	0.01
NJ-Rahway City	4,608	10/1/2022	12/31/2022	8/26/2022	46.00	-126.6	12.23	(68.40)	0.03%	(0.02)
NJ-Ridgefield Borough	75,103	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.42%	(0.02)
NJ-Ridgefield Borough	73,874	7/1/2022	9/30/2022	1/27/2022	46.00	-245.6	12.23	(187.37)	0.41%	(0.78)
NJ-Ridgefield Borough	44,599	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.25%	(0.09)
NJ-Ridgefield Borough	811	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.00%	(0.00)
NJ-Ridgefield Borough	75,103	4/1/2022	6/30/2022	3/28/2022	45.50	-93.3	12.23	(35.62)	0.42%	(0.15)
NJ-Ridgewood Village	6,965	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.04%	(0.01)
NJ-Ridgewood Village	6,965	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.04%	(0.00)
NJ-Ridgewood Village	6,965	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.04%	(0.04)
NJ-Ridgewood Village	7,222	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.04%	(0.01)
NJ-Ringwood Borough	5,602	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.03%	(0.00)
NJ-Ringwood Borough	5,602	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.03%	(0.03)
NJ-Ringwood Borough	5,755	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.03%	0.00
NJ-Ringwood Borough	5,753	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.03%	(0.03)
NJ-Riverside Township	724	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.00%	(0.00)
NJ-Riverside Township	11,818	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.07%	(0.02)
NJ-Riverside Township	10,575	4/1/2022	6/30/2022	6/2/2022	45.50	-27.3	12.23	30.43	0.06%	0.02
NJ-Riverside Township	11,662	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.07%	(0.01)
NJ-Roseland Borough	65,753	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.37%	(0.06)
NJ-Roseland Borough	63,333	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.35%	(0.02)
NJ-Roseland Borough	63,333	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.35%	(0.34)
NJ-Roseland Borough	64,433	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.36%	(0.05)

NJ-Roselle Borough	3,828	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.02%	(0.00)
NJ-Roselle Borough	3,844	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5	12.23	(14.32)	0.02%	(0.00)
NJ-Roselle Borough	3,791	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.02%	(0.00)
NJ-Roselle Borough	3,791	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Runnemede Borough	2,825	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-Runnemede Borough	2,825	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.02%	(0.02)
NJ-Runnemede Borough	2,962	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.02%	0.00
NJ-Runnemede Borough	2,962	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.02%	(0.02)
NJ-Saddle Brook Township	9,960	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.06%	(0.00)
NJ-Saddle Brook Township	9,960	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.06%	(0.05)
NJ-Saddle Brook Township	8,654	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.05%	(0.02)
NJ-Saddle Brook Township	8,655	7/1/2022	9/30/2022	9/26/2022	46.00	-3.4	12.23	54.80	0.05%	0.03
NJ-Sayreville Borough	15,269	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.09%	(0.02)
NJ-Sayreville Borough	15,269	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4		(107.92)	0.09%	(0.09)
NJ-Sayreville Borough	15,686	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4		(27.41)	0.09%	(0.02)
NJ-Sayreville Borough	15,531	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5		(26.55)	0.09%	(0.02)
NJ-Scotch Plains Township	13,452	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.08%	(0.00)
NJ-Scotch Plains Township	13,452	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.08%	(0.07)
NJ-Scotch Plains Township	13,497	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.08%	0.00
NJ-Scotch Plains Township	13,497	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.08%	(0.07)
NJ-Secaucus Town	82,253	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.46%	(0.02)
NJ-Secaucus Town	82,253	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.46%	(0.44)
NJ-Secaucus Town	81,948	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6	12.23	0.60	0.46%	0.00
NJ-Secaucus Town	81,948	10/1/2022	12/31/2022	8/3/2022	46.00	-149.6	12.23	(91.40)	0.46%	(0.42)
NJ-Somerville Borough	12,286	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.07%	(0.00)
NJ-Somerville Borough	12,286	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.07%	(0.07)
NJ-Somerville Borough	12,262	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.07%	0.00
NJ-Somerville Borough	12,262	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.07%	(0.06)
NJ-South Brunswick Township	72,531	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.41%	(0.06)
NJ-South Brunswick Township	75,753	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.42%	(0.02)
NJ-South Brunswick Township	75,753	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.42%	(0.41)
NJ-South Brunswick Township	80,229	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.45%	(0.10)
NJ-South Hackensack Township	2,153	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-South Hackensack Township	2,153	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.01%	(0.01)
NJ-South Hackensack Township	1,627	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.01%	(0.00)
NJ-South Hackensack Township	1,597	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.01%	(0.00)
NJ-South Orange Village Township	3,350	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-South Orange Village Township	3,350	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.02%	(0.02)
NJ-South Orange Village Township	3,587	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.02%	(0.00)
NJ-South Orange Village Township	3,597	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.02%	(0.01)
NJ-South Orange Village Township	673	7/1/2022	9/30/2022	8/26/2022	46.00	-34.6	12.23	23.60	0.00%	0.00
NJ-South Plainfield Borough	496	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.00%	(0.00)
NJ-South Plainfield Borough	496	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.00%	(0.00)
NJ-South Plainfield Borough	508	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.00%	(0.00)
NJ-South Plainfield Borough	531	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.00%	(0.00)
NJ-Southampton Township	1,256	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.01%	(0.00)
NJ-Southampton Township	1,215	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.01%	(0.00)
NJ-Southampton Township	1,215	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.01%	(0.01)
NJ-Southampton Township	1,282	10/1/2022	12/31/2022	10/24/2022	46.00	-67.4	12.23	(9.15)	0.01%	(0.00)
NJ-Springfield Township	65,794	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.37%	(0.06)
NJ-Springfield Township	44,563	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.25%	(0.01)
NJ-Springfield Township	44,563	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.25%	(0.24)
NJ-Springfield Township	59,037	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.33%	(0.07)
NJ-Summit City	20,515	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.11%	(0.02)
NJ-Summit City	21,585	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.12%	(0.01)

NJ-Summit City	21,585	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.12%	(0.12)
NJ-Summit City	21,975	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.12%	(0.03)
NJ-Teaneck Township	4,055	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.02%	(0.00)
NJ-Teaneck Township	3,936	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5	12.23	(14.32)	0.02%	(0.00)
NJ-Teaneck Township	4,042	1/1/2022	3/31/2022	1/13/2022	45.00	-76.3	12.23	(19.10)	0.02%	(0.00)
NJ-Teaneck Township	4,042	4/1/2022	6/30/2022	1/13/2022	45.50	-167.3	12.23	(109.60)	0.02%	(0.02)
NJ-Totowa Borough	77,400	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.43%	(0.02)
NJ-Totowa Borough	77,400	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.43%	(0.41)
NJ-Totowa Borough	81,239	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.46%	0.07
NJ-Totowa Borough	81,239	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.46%	(0.35)
NJ-Trenton City	29,400	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.16%	(0.00)
NJ-Trenton City	27,388	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.15%	(0.02)
NJ-Trenton City	29,400	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.16%	(0.01)
NJ-Trenton City	29,400	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.16%	(0.16)
NJ-Union Township	33,675	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.19%	(0.01)
NJ-Union Township	33,675	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.19%	(0.18)
NJ-Union Township	35,694	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.20%	0.01
NJ-Union Township	35,001	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.20%	(0.17)
NJ-Union Township	848	10/1/2022	12/31/2022	12/13/2022	46.00	-17.5	12.23	40.73	0.00%	0.00
NJ-Union Township	848	10/1/2022	12/31/2022	12/14/2022	46.00	-16.5	12.23	41.72	0.00%	0.00
NJ-Waldwick Borough	37,612	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.21%	(0.01)
NJ-Waldwick Borough	37,612	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.21%	(0.20)
NJ-Waldwick Borough	39,335	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.22%	(0.05)
NJ-Waldwick Borough	38,797	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.22%	(0.08)
NJ-Wayne Township	7,020	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.04%	(0.00)
NJ-Wayne Township	7,020	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.04%	(0.04)
NJ-Wayne Township	7,035	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.04%	0.00
NJ-Wayne Township	7,035	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.04%	(0.03)
NJ-West Caldwell Township	9,209	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.05%	(0.01)
NJ-West Caldwell Township	9,106	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.05%	(0.00)
NJ-West Caldwell Township	9,106	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.05%	(0.05)
NJ-West Caldwell Township	9,278	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.05%	(0.01)
NJ-West Deptford Township	16,451	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.09%	(0.00)
NJ-West Deptford Township	16,451	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.09%	(0.09)
NJ-West Deptford Township	16,566	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.09%	0.01
NJ-West Deptford Township	16,566	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.09%	(0.08)
NJ-West Milford Township	49	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.00%	(0.00)
NJ-West Milford Township	49	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.00%	(0.00)
NJ-West Milford Township	50	7/1/2022	9/30/2022	7/11/2022	46.00	-80.6	12.23	(22.35)	0.00%	(0.00)
NJ-West Milford Township	51	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.00%	(0.00)
NJ-West New York Town	9,131	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.05%	(0.00)
NJ-West New York Town	9,131	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.05%	(0.05)
NJ-West New York Town	9,304	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.05%	0.00
NJ-West New York Town	9,304	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.05%	(0.04)
NJ-West Orange Township	76,875	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.43%	(0.02)
NJ-West Orange Township	76,875	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.43%	(0.41)
NJ-West Orange Township	81,396	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.18)	0.46%	(0.07)
NJ-West Orange Township	78,217	10/1/2022	12/31/2022	10/19/2022	46.00	-72.5	12.23	(14.32)	0.44%	(0.06)
NJ-West Windsor Township	9,508	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.05%	(0.00)
NJ-West Windsor Township	9,508	10/1/2022	12/31/2022	8/1/2022	46.00	-151.6	12.23	(93.38)	0.05%	(0.05)
NJ-West Windsor Township	9,351	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.05%	(0.00)
NJ-West Windsor Township	9,351	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.05%	(0.05)
NJ-Westampton Township	927	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Westampton Township	927	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.01%	(0.00)
NJ-Westampton Township	999	7/1/2022	9/30/2022	8/9/2022	46.00	-51.3	12.23	6.96	0.01%	0.00
NJ-Westampton Township	999	10/1/2022	12/31/2022	8/10/2022	46.00	-142.7	12.23	(84.47)	0.01%	(0.00)

NJ-Westfield Town	9,928	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.06%	(0.01)
NJ-Westfield Town	9,947	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.06%	(0.00)
NJ-Westfield Town	9,947	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.06%	(0.05)
NJ-Westfield Town	9,910	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.06%	(0.01)
NJ-Westwood Borough	2,098	10/1/2022	12/31/2022	10/18/2022	46.00	-73.5	12.23	(15.23)	0.01%	(0.00)
NJ-Westwood Borough	1,967	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.01%	(0.00)
NJ-Westwood Borough	1,967	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.01%	(0.01)
NJ-Westwood Borough	2,177	7/1/2022	9/30/2022	7/18/2022	46.00	-73.4	12.23	(15.19)	0.01%	(0.00)
NJ-Willingboro Township	2,197	7/1/2022	9/30/2022	8/3/2022	46.00	-57.6		(11.63)	0.01%	(0.00)
NJ-Willingboro Township	2,206	1/1/2022	3/31/2022	1/21/2022	45.00	-68.3		(23.30)	0.01%	(0.00)
NJ-Willingboro Township	2,206	4/1/2022	6/30/2022	1/21/2022	45.50	-159.3		(113.80)	0.01%	(0.01)
NJ-Willingboro Township	2,199	10/1/2022	12/31/2022	9/28/2022	46.00	-93.5		(47.51)	0.01%	(0.01)
NJ-Winslow Township	22,565	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.13%	(0.01)
NJ-Winslow Township	22,565	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.13%	(0.12)
NJ-Winslow Township	23,086	7/1/2022	9/30/2022	8/18/2022	46.00	-42.4	12.23	15.78	0.13%	0.02
NJ-Winslow Township	23,086	10/1/2022	12/31/2022	8/18/2022	46.00	-134.4	12.23	(76.22)	0.13%	(0.10)
								-		
NJ-Woodbridge Township	92,312	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6		(17.60)	0.52%	(0.09)
NJ-Woodbridge Township	84,973	7/1/2022	9/30/2022	8/2/2022	46.00	-58.7		(12.68)	0.48%	(0.06)
NJ-Woodbridge Township	84,973	10/1/2022	12/31/2022	8/2/2022	46.00	-150.7		(104.68)	0.48%	(0.50)
NJ-Woodbridge Township	92,312	4/1/2022	6/30/2022	3/23/2022	45.50	-98.6		(53.11)	0.52%	(0.27)
								-		
NJ-Woodbury City	3,167	7/1/2022	9/30/2022	8/1/2022	46.00	-59.6	12.23	(1.38)	0.02%	(0.00)
NJ-Woodbury City	3,025	1/1/2022	3/31/2022	1/27/2022	45.00	-62.6	12.23	(5.37)	0.02%	(0.00)
NJ-Woodbury City	3,025	4/1/2022	6/30/2022	1/27/2022	45.50	-153.4	12.23	(95.69)	0.02%	(0.02)
NJ-Woodbury City	3,044	10/1/2022	12/31/2022	9/26/2022	46.00	-95.3	12.23	(37.11)	0.02%	(0.01)
	$ 17,848,322									(39.09)

Newark City Tax

Weekly Payroll (A)	Pay Period Beginning (B)	Pay Period End (C)	Paid On (D)	Net Pay (E)	Midpoint of Pay Period (F)	Payment Lead Time (G)	Total Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	$ 6,738	45.00	29.00	74.00	1.59%	1.18
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	6,737	45.00	29.00	74.00	1.59%	1.18
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,025	45.00	29.00	74.00	1.66%	1.23
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	6,935	45.00	29.00	74.00	1.64%	1.21
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,249	45.00	29.00	74.00	1.71%	1.27
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,033	45.00	29.00	74.00	1.66%	1.23
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	6,846	45.00	29.00	74.00	1.62%	1.20
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,054	45.00	29.00	74.00	1.66%	1.23
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	6,984	45.00	29.00	74.00	1.65%	1.22
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,176	45.00	29.00	74.00	1.69%	1.25
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,326	45.00	29.00	74.00	1.73%	1.28
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	7,578	45.00	29.00	74.00	1.79%	1.32
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	8,958	45.00	29.00	74.00	2.11%	1.56
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,413	45.50	29.00	74.50	1.99%	1.48
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,309	45.50	29.00	74.50	1.96%	1.46
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,076	45.50	29.00	74.50	1.91%	1.42
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	7,845	45.50	29.00	74.50	1.85%	1.38
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,029	45.50	29.00	74.50	1.90%	1.41
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	7,791	45.50	29.00	74.50	1.84%	1.37
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,095	45.50	29.00	74.50	1.91%	1.42
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,231	45.50	29.00	74.50	1.94%	1.45
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,560	45.50	29.00	74.50	2.02%	1.51
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,679	45.50	29.00	74.50	2.05%	1.53
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,428	45.50	29.00	74.50	1.99%	1.48
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,327	45.50	29.00	74.50	1.97%	1.46
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	8,242	45.50	29.00	74.50	1.95%	1.45
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,798	46.00	31.00	77.00	2.08%	1.60
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,662	46.00	31.00	77.00	2.04%	1.57
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,861	46.00	31.00	77.00	2.09%	1.61
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,705	46.00	31.00	77.00	2.05%	1.58
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,941	46.00	31.00	77.00	2.11%	1.62
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,449	46.00	31.00	77.00	1.99%	1.54
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,949	46.00	31.00	77.00	2.11%	1.63
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,788	46.00	31.00	77.00	2.07%	1.60
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,972	46.00	31.00	77.00	2.12%	1.63
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,766	46.00	31.00	77.00	2.07%	1.59
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,752	46.00	31.00	77.00	2.07%	1.59
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,948	46.00	31.00	77.00	2.11%	1.63
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	8,769	46.00	31.00	77.00	2.07%	1.59
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,454	46.00	31.00	77.00	2.00%	1.54
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,498	46.00	31.00	77.00	2.01%	1.54
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	9,045	46.00	31.00	77.00	2.13%	1.64
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,455	46.00	31.00	77.00	2.00%	1.54
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,351	46.00	31.00	77.00	1.97%	1.52
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,282	46.00	31.00	77.00	1.95%	1.51
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,494	46.00	31.00	77.00	2.00%	1.54
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,446	46.00	31.00	77.00	1.99%	1.53
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,061	46.00	31.00	77.00	1.90%	1.46
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,178	46.00	31.00	77.00	1.93%	1.49
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,331	46.00	31.00	77.00	1.97%	1.51
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,073	46.00	31.00	77.00	1.91%	1.47
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	8,012	46.00	31.00	77.00	1.89%	1.46
				$ 423,702					75.71

Bi-Weekly Payroll	Pay Period Beginning	Pay Period End	Paid On	Net Pay	Midpoint of Pay Period	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	$ 27,773	45.00	29.00	74.00	3.18%	2.35
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	27,457	45.00	29.00	74.00	3.14%	2.33
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	27,773	45.00	29.00	74.00	3.18%	2.35
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	37,957	45.00	29.00	74.00	4.35%	3.22
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	181,703	45.00	29.00	74.00	20.80%	15.39
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	27,776	45.00	29.00	74.00	3.18%	2.35
Newark City Tax	1/1/2022	3/31/2022	4/29/2022	28,221	45.00	29.00	74.00	3.23%	2.39
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	28,884	45.50	29.00	74.50	3.31%	2.46
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	28,426	45.50	29.00	74.50	3.25%	2.42
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	28,439	45.50	29.00	74.50	3.26%	2.43
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	6,615	45.50	29.00	74.50	0.76%	0.56
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	27,850	45.50	29.00	74.50	3.19%	2.38
Newark City Tax	4/1/2022	6/30/2022	7/29/2022	27,818	45.50	29.00	74.50	3.18%	2.37
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	28,597	46.00	31.00	77.00	3.27%	2.52
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	28,301	46.00	31.00	77.00	3.24%	2.49
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	29,138	46.00	31.00	77.00	3.34%	2.57
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	28,375	46.00	31.00	77.00	3.25%	2.50
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	28,934	46.00	31.00	77.00	3.31%	2.55
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	27,965	46.00	31.00	77.00	3.20%	2.47
Newark City Tax	7/1/2022	9/30/2022	10/31/2022	27,988	46.00	31.00	77.00	3.20%	2.47
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	28,118	46.00	31.00	77.00	3.22%	2.48
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	28,311	46.00	31.00	77.00	3.24%	2.50
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	27,806	46.00	31.00	77.00	3.18%	2.45
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	27,695	46.00	31.00	77.00	3.17%	2.44
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	28,006	46.00	31.00	77.00	3.21%	2.47
Newark City Tax	10/1/2022	12/31/2022	1/31/2023	27,558	46.00	31.00	77.00	3.15%	2.43
				$ 873,483					75.34

	Amount	Expense Lead	Weighting	Weighted Lead
Weekly	423,702.09	75.71	32.7%	24.73
Bi-Weekly	873,482.68	75.34	67.3%	50.73
Weighted Lead for Weekly and Bi-Weekly Payroll	$ 1,297,184.77			75.46 days

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
INCOME TAXES

SUMMARY

Federal Income Tax	37.88	days
State (CBT) Tax	(47.25)	days

Federal Income Tax (A)	Period Beginning (B)	Period Ending (C)	Due Date (D)	Weighting Factor or % of Payment Due (E)	Service Lead (F)	Payment Lead Time (G)	Total Lead (H)	Weighted Lead (I)
Federal Income Tax	1/1/2022	3/31/2022	4/15/2022	25.00%	45.00	15.00	60.00	15.00
Federal Income Tax	4/1/2022	6/30/2022	6/15/2022	25.00%	45.50	(15.00)	30.50	7.63
Federal Income Tax	7/1/2022	9/30/2022	9/15/2022	25.00%	46.00	(15.00)	31.00	7.75
Federal Income Tax	10/1/2022	12/31/2022	12/15/2022	25.00%	46.00	(16.00)	30.00	7.50
								37.88

Payments dates reflect statutory deadlines

Current State CBT (A)	Period Beginning (B)	Period Ending (C)	Due Date (D)	Weighting Factor or % of Payment Due (E)	Service Lead (F)	Payment Lead Time (G)	Total Lead (H)	Weighted Lead (I)
State CBT	1/1/2022	12/31/2022	4/15/2022	25.00%	182.50	(260.00)	(77.50)	(19.38)
State CBT	1/1/2022	12/31/2022	5/15/2022	50.00%	182.50	(230.00)	(47.50)	(23.75)
State CBT	1/1/2022	12/31/2022	6/15/2022	25.00%	182.50	(199.00)	(16.50)	(4.13)
								(47.25)

Payments dates reflect statutory deadlines

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
LONG-TERM INTEREST EXPENSE

Weighted Lead 91.75 days

(A)	Paid Date (B)	Amount (C)	Period Beginning (D)	Period Ending (E)	Midpoint of Service Period (F)	Weighting Factor (G)	Weighted Lead Time (H)
Mortgage Bond Series 8.000%	6/1/2022	$ 298,516	12/1/2021	6/1/2022	91.50	0.07%	0.06
Mortgage Bond Series 8.000%	12/1/2022	298,516	6/1/2022	12/1/2022	92.00	0.07%	0.07
Mortgage Bond Series 5.000%	1/1/2022	188,445	7/1/2021	1/1/2022	92.50	0.04%	0.04
Mortgage Bond Series 5.000%	7/1/2022	188,445	1/1/2022	7/1/2022	91.00	0.04%	0.04
MTN Series D 5.250%	1/1/2022	6,562,500	7/1/2021	1/1/2022	92.50	1.56%	1.44
MTN Series D 5.250%	7/1/2022	6,562,500	1/1/2022	7/1/2022	91.00	1.56%	1.42
MTN Series D 5.700%	6/1/2022	7,125,000	12/1/2021	6/1/2022	91.50	1.69%	1.55
MTN Series D 5.700%	12/1/2022	7,125,000	6/1/2022	12/1/2022	92.00	1.69%	1.56
MTN Series E 5.800% Due 2037	5/1/2022	10,150,000	11/1/2021	5/1/2022	91.00	2.41%	2.19
MTN Series E 5.800% Due 2037	11/1/2022	10,150,000	5/1/2022	11/1/2022	92.50	2.41%	2.23
MTN Series G 5.375% Due 2039	5/1/2022	6,718,750	11/1/2021	5/1/2022	91.00	1.60%	1.45
MTN Series G 5.375% Due 2039	11/1/2022	6,718,750	5/1/2022	11/1/2022	92.50	1.60%	1.48
MTN Series G 5.5% Due 2040	3/1/2022	8,250,000	9/1/2021	3/1/2022	91.00	1.96%	1.78
MTN Series G 5.5% Due 2040	9/1/2022	8,250,000	3/1/2022	9/1/2022	92.50	1.96%	1.81
MTN Series H 3.95% Due 2042	5/1/2022	8,887,500	11/1/2021	5/1/2022	91.00	2.11%	1.92
MTN Series H 3.95% Due 2042	11/1/2022	8,887,500	5/1/2022	11/1/2022	92.50	2.11%	1.95
MTN Series H 3.65% Due 2042	3/1/2022	6,387,500	9/1/2021	3/1/2022	91.00	1.52%	1.38
MTN Series H 3.65% Due 2042	9/1/2022	6,387,500	3/1/2022	9/1/2022	92.50	1.52%	1.40
MTN Series H 3.80% Due 2043	1/1/2022	7,600,000	7/1/2021	1/1/2022	92.50	1.80%	1.67
MTN Series H 3.80% Due 2043	7/1/2022	7,600,000	1/1/2022	7/1/2022	91.00	1.80%	1.64
MTN Series I 2.375% Due 2023	5/15/2022	5,937,500	11/15/2021	5/15/2022	91.00	1.41%	1.28
MTN Series I 2.375% Due 2023	11/15/2022	5,937,500	5/15/2022	11/15/2022	92.50	1.41%	1.30
MTN Series I 3.750% Due 2024	3/15/2022	4,687,500	9/15/2021	3/15/2022	91.00	1.11%	1.01
MTN Series I 3.750% Due 2024	9/15/2022	4,687,500	3/15/2022	9/15/2022	92.50	1.11%	1.03
MTN Series I 4.000% Due 2044	6/1/2022	5,000,000	12/1/2021	6/1/2022	91.50	1.19%	1.09
MTN Series I 4.000% Due 2044	12/1/2022	5,000,000	6/1/2022	12/1/2022	92.00	1.19%	1.09
MTN Series J 3.150% Due 2024	2/15/2022	3,937,500	8/15/2021	2/15/2022	92.50	0.93%	0.86
MTN Series J 3.150% Due 2024	8/15/2022	3,937,500	2/15/2022	8/15/2022	91.00	0.93%	0.85
MTN Series J 3.050% Due 2024	5/15/2022	3,812,500	11/15/2021	5/15/2022	91.00	0.91%	0.82
MTN Series J 3.050% Due 2024	11/15/2022	3,812,500	5/15/2022	11/15/2022	92.50	0.91%	0.84
MTN Series K 3.000% Due 2025	5/15/2022	5,250,000	11/15/2021	5/15/2022	91.00	1.25%	1.13
MTN Series K 3.000% Due 2025	11/15/2022	5,250,000	5/15/2022	11/15/2022	92.50	1.25%	1.15
MTN Series K 4.050% Due 2045	5/1/2022	5,062,500	11/1/2021	5/1/2022	91.00	1.20%	1.09
MTN Series K 4.050% Due 2045	11/1/2022	5,062,500	5/1/2022	11/1/2022	92.50	1.20%	1.11
MTN Series K 4.150% Due 2045	5/1/2022	5,187,500	11/1/2021	5/1/2022	91.00	1.23%	1.12
MTN Series K 4.150% Due 2045	11/1/2022	5,187,500	5/1/2022	11/1/2022	92.50	1.23%	1.14

(A)	Paid Date (B)	Amount (C)	Period Beginning (D)	Period Ending (E)	Midpoint of Service Period (F)	Weighting Factor (G)	Weighted Lead Time (H)
MTN Series K 3.80% Due 2046	3/1/2022	10,450,000	9/1/2021	3/1/2022	91.00	2.48%	2.26
MTN Series K 3.80% Due 2046	9/1/2022	10,450,000	3/1/2022	9/1/2022	92.50	2.48%	2.30
MTN Series L 2.25% Due 2026	3/15/2022	4,781,250	9/15/2021	3/15/2022	91.00	1.14%	1.03
MTN Series L 2.25% Due 2026	9/15/2022	4,781,250	3/15/2022	9/15/2022	92.50	1.14%	1.05
MTN Series L 3.00% Due 2027	5/15/2022	6,375,000	11/15/2021	5/15/2022	91.00	1.51%	1.38
MTN Series L 3.00% Due 2027	11/15/2022	6,375,000	5/15/2022	11/15/2022	92.50	1.51%	1.40
MTN Series L 3.60% Due 2047	6/1/2022	6,300,000	12/1/2021	6/1/2022	91.50	1.50%	1.37
MTN Series L 3.60% Due 2047	12/1/2022	6,300,000	6/1/2022	12/1/2022	92.00	1.50%	1.38
MTN Series M 3.70% Due 2028	5/1/2022	6,937,500	11/1/2021	5/1/2022	91.00	1.65%	1.50
MTN Series M 3.70% Due 2028	11/1/2022	6,937,500	5/1/2022	11/1/2022	92.50	1.65%	1.52
MTN Series M 4.05% Due 2048	5/1/2022	6,581,250	11/1/2021	5/1/2022	91.00	1.56%	1.42
MTN Series M 4.05% Due 2048	11/1/2022	6,581,250	5/1/2022	11/1/2022	92.50	1.56%	1.45
MTN Series M 3.25% Due 2023	3/1/2022	5,281,250	9/1/2021	3/1/2022	91.00	1.25%	1.14
MTN Series M 3.25% Due 2023	9/1/2022	5,281,250	3/1/2022	9/1/2022	92.50	1.25%	1.16
MTN Series M 3.65% Due 2028	3/1/2022	5,931,250	9/1/2021	3/1/2022	91.00	1.41%	1.28
MTN Series M 3.65% Due 2028	9/1/2022	5,931,250	3/1/2022	9/1/2022	92.50	1.41%	1.30
MTN Series M 3.20% Due 2029	5/15/2022	6,000,000	11/15/2021	5/15/2022	91.00	1.42%	1.30
MTN Series M 3.20% Due 2029	11/15/2022	6,000,000	5/15/2022	11/15/2022	92.50	1.42%	1.32
MTN Series M 3.85% Due 2049	5/1/2022	7,218,750	11/1/2021	5/1/2022	91.00	1.71%	1.56
MTN Series M 3.85% Due 2049	11/1/2022	7,218,750	5/1/2022	11/1/2022	92.50	1.71%	1.59
MTN Series M 3.20% Due 2049	2/1/2022	6,400,000	8/1/2021	2/1/2022	92.50	1.52%	1.41
MTN Series M 3.20% Due 2049	8/1/2022	6,400,000	2/1/2022	8/1/2022	91.00	1.52%	1.38
MTN Series N 2.45% Due 2030	1/15/2022	3,675,000	7/15/2021	1/15/2022	92.50	0.87%	0.81
MTN Series N 2.45% Due 2030	7/15/2022	3,675,000	1/15/2022	7/15/2022	91.00	0.87%	0.79
MTN Series N 3.15% Due 2050	1/1/2022	4,725,000	7/1/2021	1/1/2022	92.50	1.12%	1.04
MTN Series N 3.15% Due 2050	7/1/2022	4,725,000	1/1/2022	7/1/2022	91.00	1.12%	1.02
MTN Series N 2.70% Due 2050	5/1/2022	5,062,500	11/1/2021	5/1/2022	91.00	1.20%	1.09
MTN Series N 2.70% Due 2050	11/1/2022	5,062,500	5/1/2022	11/1/2022	92.50	1.20%	1.11
MTN Series N 2.05% Due 2050	2/1/2022	3,843,750	8/1/2021	2/1/2022	92.50	0.91%	0.84
MTN Series N 2.05% Due 2050	8/1/2022	3,843,750	2/1/2022	8/1/2022	91.00	0.91%	0.83
MTN Series N 0.95% Due 2026	3/15/2022	2,137,500	9/15/2021	3/15/2022	91.00	0.51%	0.46
MTN Series N 0.95% Due 2026	9/15/2022	2,137,500	3/15/2022	9/15/2022	92.50	0.51%	0.47
MTN Series N 3.00% Due 2051	3/1/2022	6,750,000	9/1/2021	3/1/2022	91.00	1.60%	1.46
MTN Series N 3.00% Due 2051	9/1/2022	6,750,000	3/1/2022	9/1/2022	92.50	1.60%	1.48
MTN Series N 1.90% Due 2031	2/15/2022	4,037,500	8/15/2021	2/15/2022	92.50	0.96%	0.89
MTN Series N 1.90% Due 2031	8/15/2022	4,037,500	2/15/2022	8/15/2022	91.00	0.96%	0.87
MTN Series P 3.10% Due 2032	3/15/2022	6,243,056	9/15/2021	3/15/2022	91.00	1.48%	1.35
MTN Series P 3.10% Due 2032	9/15/2022	6,243,056	3/15/2022	9/15/2022	92.50	1.48%	1.37
MTN Series P 4.90% Due 2032	6/15/2022	789,444	12/15/2021	6/15/2022	91.50	0.19%	0.17
MTN Series P 4.90% Due 2032	12/15/2022	789,444	6/15/2022	12/15/2022	92.00	0.19%	0.17
		$ 421,126,422					91.75

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
AFFILIATE TRANSACTIONS

Service Company Expense 35.91 days

Service Company Expense (A)	Service Start Date (B)	Service End Date (C)	Payment Date (D)	Payment Amount (E)	Service Lead Time (F)	Processing Lead Time (G)	Total Unweighted Lead Time (H)	Weighting Factor (I)	Weighted Lead Time (J)
January 2022	1/1/2022	1/31/2022	2/22/2022	$ 57,498,531.99	15.50	22.00	37.50	6.31%	2.37
February 2022	2/1/2022	2/28/2022	3/21/2022	74,154,326	14.00	21.00	35.00	8.14%	2.85
March 2022	3/1/2022	3/31/2022	4/22/2022	84,726,172	15.50	22.00	37.50	9.30%	3.49
April 2022	4/1/2022	4/30/2022	5/20/2022	73,406,453	15.00	20.00	35.00	8.05%	2.82
May 2022	5/1/2022	5/31/2022	6/21/2022	77,842,122	15.50	21.00	36.50	8.54%	3.12
June 2022	6/1/2022	6/30/2022	7/20/2022	78,541,347	15.00	20.00	35.00	8.62%	3.02
July 2022	7/1/2022	7/31/2022	8/22/2022	69,662,855	15.50	22.00	37.50	7.64%	2.87
August 2022	8/1/2022	8/31/2022	9/20/2022	70,782,167	15.50	20.00	35.50	7.77%	2.76
September 2022	9/1/2022	9/30/2022	10/20/2022	84,651,485	15.00	20.00	35.00	9.29%	3.25
October 2022	10/1/2022	10/31/2022	11/21/2022	66,900,459	15.50	21.00	36.50	7.34%	2.68
November 2022	11/1/2022	11/30/2022	12/20/2022	77,597,208	15.00	20.00	35.00	8.51%	2.98
December 2022	12/1/2022	12/31/2022	1/20/2023	95,630,055	15.50	20.00	35.50	10.49%	3.72
				$ 911,393,180.57					35.91

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
TAXES OTHER THAN INCOME TAXES

New Jersey Energy Sales Tax (48.71) days

New Jersey Energy Sales Tax (A)	Amount Paid (B)	Period Beginning (C)	Period End (D)	Payment Date (E)	Service Lead (F)	Payment Lead Time (G)	Total Lead (H)	Weighting Factor (I)	Weighted Lead (J)
January 2022	$ 43,469,335	1/1/2022	1/31/2022	2/20/2022	15.50	20.00	35.50	10%	3.55
February 2022	46,496,553	2/1/2022	2/28/2022	3/20/2022	14.00	20.00	34.00	11%	3.64
March 2022	39,566,998	3/1/2022	3/31/2022	4/20/2022	15.50	20.00	35.50	9%	3.23
April 2022	31,558,904	4/1/2022	4/30/2022	5/20/2022	15.00	20.00	35.00	7%	2.54
May 2022	26,809,289	5/1/2022	5/31/2022	6/20/2022	15.50	20.00	35.50	6%	2.19
June 2022	30,955,748	6/1/2022	6/30/2022	7/20/2022	15.00	20.00	35.00	7%	2.49
July 2022	37,947,357	7/1/2022	7/31/2022	5/20/2022	15.50	(72.00)	(56.50)	9%	(4.93)
August 2022	39,722,520	8/1/2022	8/31/2022	5/20/2022	15.50	(103.00)	(87.50)	9%	(8.00)
September 2022	35,014,205	9/1/2022	9/30/2022	5/20/2022	15.00	(133.00)	(118.00)	8%	(9.50)
October 2022	26,061,356	10/1/2022	10/31/2022	5/20/2022	15.50	(164.00)	(148.50)	6%	(8.90)
November 2022	30,618,975	11/1/2022	11/30/2022	5/20/2022	15.00	(194.00)	(179.00)	7%	(12.61)
December 2022	46,500,491	12/1/2022	12/31/2022	5/20/2022	15.50	(225.00)	(209.50)	11%	(22.41)
	$ 434,721,731								(48.71)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
LEAD LAG STUDY - Electric and Gas
ACCOUNT PAYABLE FLOAT

Account Payable Float 12.23 days

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466871	134664	$ 32,170	8/16/2022	8/19/2022	3	0.008%	0.0003
4000466872	134664	35,900	8/16/2022	8/19/2022	3	0.009%	0.0003
4000466873	134664	39,243	8/16/2022	8/19/2022	3	0.010%	0.0003
4000466874	134664	42,189	8/16/2022	8/19/2022	3	0.011%	0.0003
4000466875	134664	56,162	8/16/2022	8/19/2022	3	0.015%	0.0004
4000466876	134664	57,659	8/16/2022	8/19/2022	3	0.015%	0.0005
4000466877	134664	82,187	8/16/2022	8/19/2022	3	0.022%	0.0007
4000466825	30475	84,211	8/15/2022	8/19/2022	4	0.022%	0.0009
4000466826	30475	53,442	8/15/2022	8/19/2022	4	0.014%	0.0006
4000466827	30475	58,033	8/15/2022	8/19/2022	4	0.015%	0.0006
4000460750	26745	78,001	2/3/2022	2/8/2022	5	0.021%	0.0010
4000461322	116332	2,983	2/23/2022	2/28/2022	5	0.001%	0.0000
4000464414	126711	7,686	6/2/2022	6/7/2022	5	0.002%	0.0001
4000465503	134664	46,306	7/6/2022	7/11/2022	5	0.012%	0.0006
4000465504	134664	48,493	7/6/2022	7/11/2022	5	0.013%	0.0006
4000465505	134664	49,318	7/6/2022	7/11/2022	5	0.013%	0.0007
4000465506	134664	53,738	7/6/2022	7/11/2022	5	0.014%	0.0007
4000465507	134664	55,690	7/6/2022	7/11/2022	5	0.015%	0.0007
4000465508	134664	58,874	7/6/2022	7/11/2022	5	0.016%	0.0008
4000465509	134664	67,443	7/6/2022	7/11/2022	5	0.018%	0.0009
4000465510	134664	41,780	7/6/2022	7/11/2022	5	0.011%	0.0006
4000465511	134664	43,283	7/6/2022	7/11/2022	5	0.011%	0.0006
4000465512	134664	44,689	7/6/2022	7/11/2022	5	0.012%	0.0006
4000466948	112215	2,990	8/18/2022	8/23/2022	5	0.001%	0.0000
4000460041	30257	7,526	1/19/2022	1/25/2022	6	0.002%	0.0001
4000460046	33956	4,208	1/19/2022	1/25/2022	6	0.001%	0.0001
4000460047	34064	1,723	1/19/2022	1/25/2022	6	0.000%	0.0000
4000460049	34658	2,000	1/19/2022	1/25/2022	6	0.001%	0.0000
4000460019	134664	8,683	1/19/2022	1/25/2022	6	0.002%	0.0001
4000460020	141101	22,974	1/19/2022	1/25/2022	6	0.006%	0.0004
4000460028	144624	17,173	1/19/2022	1/25/2022	6	0.005%	0.0003
4000460080	144773	625	1/20/2022	1/26/2022	6	0.000%	0.0000
4000460284	143011	5,800	1/26/2022	2/1/2022	6	0.002%	0.0001
4000460438	33956	6,057	1/27/2022	2/2/2022	6	0.002%	0.0001
4000460439	34064	125	1/27/2022	2/2/2022	6	0.000%	0.0000
4000460442	34558	23,000	1/27/2022	2/2/2022	6	0.006%	0.0004
4000460331	142942	26,330	1/27/2022	2/2/2022	6	0.007%	0.0004
4000460332	143111	1,700	1/27/2022	2/2/2022	6	0.000%	0.0000
4000460333	143312	64,783	1/27/2022	2/2/2022	6	0.017%	0.0010
4000460334	143477	8,559	1/27/2022	2/2/2022	6	0.002%	0.0001
4000460336	143637	3,750	1/27/2022	2/2/2022	6	0.001%	0.0001
4000460500	33075	41,582	1/28/2022	2/3/2022	6	0.011%	0.0007
4000460505	33081	8,506	1/28/2022	2/3/2022	6	0.002%	0.0001
4000460683	116051	4,043	2/2/2022	2/8/2022	6	0.001%	0.0001
4000460699	143577	7,808	2/2/2022	2/8/2022	6	0.002%	0.0001
4000460704	144510	2,000	2/2/2022	2/8/2022	6	0.001%	0.0000
4000460740	11305	3,450	2/3/2022	2/9/2022	6	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460748	26642	11,951	2/3/2022	2/9/2022	6	0.003%	0.0002
4000460761	126775	5,169	2/3/2022	2/9/2022	6	0.001%	0.0001
4000460732	118807	55	2/3/2022	2/9/2022	6	0.000%	0.0000
4000460733	126775	1,128	2/3/2022	2/9/2022	6	0.000%	0.0000
4000460734	126775	36,000	2/3/2022	2/9/2022	6	0.009%	0.0006
4000460907	24383	470	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460911	27636	3,250	2/9/2022	2/15/2022	6	0.001%	0.0001
4000460916	32356	1,633	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460918	34064	341	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460923	126775	634	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460889	116332	64,626	2/9/2022	2/15/2022	6	0.017%	0.0010
4000460890	116384	78	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460896	142942	13,852	2/9/2022	2/15/2022	6	0.004%	0.0002
4000460898	144773	625	2/9/2022	2/15/2022	6	0.000%	0.0000
4000460957	24383	880	2/10/2022	2/16/2022	6	0.000%	0.0000
4000460969	30475	59,056	2/10/2022	2/16/2022	6	0.016%	0.0009
4000460972	34064	163	2/10/2022	2/16/2022	6	0.000%	0.0000
4000460973	34341	6,300	2/10/2022	2/16/2022	6	0.002%	0.0001
4000460974	34391	332,837	2/10/2022	2/16/2022	6	0.088%	0.0053
4000460975	34558	25,000	2/10/2022	2/16/2022	6	0.007%	0.0004
4000460976	34658	320	2/10/2022	2/16/2022	6	0.000%	0.0000
4000460932	4909	4,592	2/10/2022	2/16/2022	6	0.001%	0.0001
4000460939	104496	38	2/10/2022	2/16/2022	6	0.000%	0.0000
4000460940	116384	630	2/10/2022	2/16/2022	6	0.000%	0.0000
4000460944	134862	157,671	2/10/2022	2/16/2022	6	0.042%	0.0025
4000460945	140752	3,703	2/10/2022	2/16/2022	6	0.001%	0.0001
4000460950	143577	9,760	2/10/2022	2/16/2022	6	0.003%	0.0002
4000461118	116384	606	2/16/2022	2/22/2022	6	0.000%	0.0000
4000461173	130315	39	2/17/2022	2/23/2022	6	0.000%	0.0000
4000461323	116384	30	2/23/2022	3/1/2022	6	0.000%	0.0000
4000461324	118807	1,149	2/23/2022	3/1/2022	6	0.000%	0.0000
4000461327	132094	100	2/23/2022	3/1/2022	6	0.000%	0.0000
4000461337	143588	1,656	2/23/2022	3/1/2022	6	0.000%	0.0000
4000461379	141101	33,710	2/24/2022	3/2/2022	6	0.009%	0.0005
4000461383	143659	40,702	2/24/2022	3/2/2022	6	0.011%	0.0006
4000461384	143659	3,762	2/24/2022	3/2/2022	6	0.001%	0.0001
4000461386	143940	8,430	2/24/2022	3/2/2022	6	0.002%	0.0001
4000461519	116971	3,000	3/1/2022	3/7/2022	6	0.001%	0.0000
4000461788	18267	11,196	3/10/2022	3/16/2022	6	0.003%	0.0002
4000461795	27013	22,793	3/10/2022	3/16/2022	6	0.006%	0.0004
4000461800	30475	52,369	3/10/2022	3/16/2022	6	0.014%	0.0008
4000461801	30475	67,237	3/10/2022	3/16/2022	6	0.018%	0.0011
4000461804	34341	6,600	3/10/2022	3/16/2022	6	0.002%	0.0001
4000461767	27094	74,816	3/10/2022	3/16/2022	6	0.020%	0.0012
4000461768	105195	3,678	3/10/2022	3/16/2022	6	0.001%	0.0001
4000461769	116384	624	3/10/2022	3/16/2022	6	0.000%	0.0000
4000461772	126640	1,627	3/10/2022	3/16/2022	6	0.000%	0.0000
4000461774	138862	92	3/10/2022	3/16/2022	6	0.000%	0.0000
4000461779	143577	10,644	3/10/2022	3/16/2022	6	0.003%	0.0002
4000461783	144948	11,046	3/10/2022	3/16/2022	6	0.003%	0.0002
4000461942	10384	2,500	3/16/2022	3/22/2022	6	0.001%	0.0000
4000461958	126775	46,698	3/16/2022	3/22/2022	6	0.012%	0.0007
4000461930	116384	53	3/16/2022	3/22/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461934	142613	6,706	3/16/2022	3/22/2022	6	0.002%	0.0001
4000461936	143477	17,572	3/16/2022	3/22/2022	6	0.005%	0.0003
4000461938	144173	16,363	3/16/2022	3/22/2022	6	0.004%	0.0003
4000461991	26659	873	3/17/2022	3/23/2022	6	0.000%	0.0000
4000461996	33770	42,864	3/17/2022	3/23/2022	6	0.011%	0.0007
4000461997	34064	1,430	3/17/2022	3/23/2022	6	0.000%	0.0000
4000461998	34341	9,900	3/17/2022	3/23/2022	6	0.003%	0.0002
4000461967	111669	331	3/17/2022	3/23/2022	6	0.000%	0.0000
4000461975	135488	8,730	3/17/2022	3/23/2022	6	0.002%	0.0001
4000461978	141101	21,834	3/17/2022	3/23/2022	6	0.006%	0.0003
4000461981	143312	48,162	3/17/2022	3/23/2022	6	0.013%	0.0008
4000461982	143338	73,800	3/17/2022	3/23/2022	6	0.019%	0.0012
4000461984	143577	9,593	3/17/2022	3/23/2022	6	0.003%	0.0002
4000461985	143940	1,500	3/17/2022	3/23/2022	6	0.000%	0.0000
4000462161	30257	80,486	3/23/2022	3/29/2022	6	0.021%	0.0013
4000462143	106840	112	3/23/2022	3/29/2022	6	0.000%	0.0000
4000462145	116384	75	3/23/2022	3/29/2022	6	0.000%	0.0000
4000462147	122334	5,000	3/23/2022	3/29/2022	6	0.001%	0.0001
4000462148	130315	156	3/23/2022	3/29/2022	6	0.000%	0.0000
4000462186	18267	11,237	3/24/2022	3/30/2022	6	0.003%	0.0002
4000462187	24825	2,882	3/24/2022	3/30/2022	6	0.001%	0.0000
4000462194	105195	1,369	3/24/2022	3/30/2022	6	0.000%	0.0000
4000462172	116384	15	3/24/2022	3/30/2022	6	0.000%	0.0000
4000462178	135488	100,806	3/24/2022	3/30/2022	6	0.027%	0.0016
4000462180	143577	10,644	3/24/2022	3/30/2022	6	0.003%	0.0002
4000462181	143659	7,302	3/24/2022	3/30/2022	6	0.002%	0.0001
4000462391	28474	2,043	3/30/2022	4/5/2022	6	0.001%	0.0000
4000462329	104752	12,700	3/30/2022	4/5/2022	6	0.003%	0.0002
4000462354	135488	22,944	3/30/2022	4/5/2022	6	0.006%	0.0004
4000462366	143465	1,000	3/30/2022	4/5/2022	6	0.000%	0.0000
4000462373	144984	1,500	3/30/2022	4/5/2022	6	0.000%	0.0000
4000462438	24385	3,329	3/31/2022	4/6/2022	6	0.001%	0.0001
4000462456	30475	1,652	3/31/2022	4/6/2022	6	0.000%	0.0000
4000462461	33956	2,838	3/31/2022	4/6/2022	6	0.001%	0.0000
4000462406	4765	54,454	3/31/2022	4/6/2022	6	0.014%	0.0009
4000462426	143588	9,637	3/31/2022	4/6/2022	6	0.003%	0.0002
4000462427	143920	73	3/31/2022	4/6/2022	6	0.000%	0.0000
4000462632	9001	29,156	4/6/2022	4/12/2022	6	0.008%	0.0005
4000462637	26338	827	4/6/2022	4/12/2022	6	0.000%	0.0000
4000462619	105195	1,582	4/6/2022	4/12/2022	6	0.000%	0.0000
4000462621	116384	634	4/6/2022	4/12/2022	6	0.000%	0.0000
4000462625	135488	2,760	4/6/2022	4/12/2022	6	0.001%	0.0000
4000462629	143577	6,405	4/6/2022	4/12/2022	6	0.002%	0.0001
4000462676	24113	1,814	4/7/2022	4/13/2022	6	0.000%	0.0000
4000462648	27094	20,638	4/7/2022	4/13/2022	6	0.005%	0.0003
4000462654	118807	825	4/7/2022	4/13/2022	6	0.000%	0.0000
4000462659	138862	62	4/7/2022	4/13/2022	6	0.000%	0.0000
4000462668	144567	1,778	4/7/2022	4/13/2022	6	0.000%	0.0000
4000462852	18267	3,920	4/13/2022	4/19/2022	6	0.001%	0.0001
4000462855	30475	47,533	4/13/2022	4/19/2022	6	0.013%	0.0008
4000462858	33956	9,165	4/13/2022	4/19/2022	6	0.002%	0.0001
4000462803	27094	5,486	4/13/2022	4/19/2022	6	0.001%	0.0001
4000462813	116384	1,160	4/13/2022	4/19/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462816	119733	1,000	4/13/2022	4/19/2022	6	0.000%	0.0000
4000462828	132849	935	4/13/2022	4/19/2022	6	0.000%	0.0000
4000462833	138862	63	4/13/2022	4/19/2022	6	0.000%	0.0000
4000462838	143633	500	4/13/2022	4/19/2022	6	0.000%	0.0000
4000462913	30228	267,490	4/14/2022	4/20/2022	6	0.071%	0.0042
4000462925	34341	16,900	4/14/2022	4/20/2022	6	0.004%	0.0003
4000462872	116332	43,229	4/14/2022	4/20/2022	6	0.011%	0.0007
4000462875	135488	1,912	4/14/2022	4/20/2022	6	0.001%	0.0000
4000462893	144955	19,743	4/14/2022	4/20/2022	6	0.005%	0.0003
4000463017	11305	1,878	4/20/2022	4/26/2022	6	0.000%	0.0000
4000463018	18267	2,423	4/20/2022	4/26/2022	6	0.001%	0.0000
4000462995	115761	56	4/20/2022	4/26/2022	6	0.000%	0.0000
4000462996	116384	383	4/20/2022	4/26/2022	6	0.000%	0.0000
4000462999	118807	383	4/20/2022	4/26/2022	6	0.000%	0.0000
4000463049	11305	1,898	4/21/2022	4/27/2022	6	0.001%	0.0000
4000463052	24385	17,461	4/21/2022	4/27/2022	6	0.005%	0.0003
4000463057	26356	1,313	4/21/2022	4/27/2022	6	0.000%	0.0000
4000463058	26361	2,584	4/21/2022	4/27/2022	6	0.001%	0.0000
4000463059	26363	3,522	4/21/2022	4/27/2022	6	0.001%	0.0001
4000463063	26639	26,528	4/21/2022	4/27/2022	6	0.007%	0.0004
4000463064	26642	6,352	4/21/2022	4/27/2022	6	0.002%	0.0001
4000463067	26659	61,088	4/21/2022	4/27/2022	6	0.016%	0.0010
4000463072	34064	138	4/21/2022	4/27/2022	6	0.000%	0.0000
4000463075	126775	1,584	4/21/2022	4/27/2022	6	0.000%	0.0000
4000463033	112215	17,896	4/21/2022	4/27/2022	6	0.005%	0.0003
4000463043	143659	5,629	4/21/2022	4/27/2022	6	0.001%	0.0001
4000463044	143920	13	4/21/2022	4/27/2022	6	0.000%	0.0000
4000463235	24385	12,701	4/27/2022	5/3/2022	6	0.003%	0.0002
4000463249	30257	67,960	4/27/2022	5/3/2022	6	0.018%	0.0011
4000463252	34064	147	4/27/2022	5/3/2022	6	0.000%	0.0000
4000463212	32842	1,614	4/27/2022	5/3/2022	6	0.000%	0.0000
4000463217	112215	6,508	4/27/2022	5/3/2022	6	0.002%	0.0001
4000463221	135488	1,164	4/27/2022	5/3/2022	6	0.000%	0.0000
4000463223	138862	46	4/27/2022	5/3/2022	6	0.000%	0.0000
4000463304	26207	2,225	4/28/2022	5/4/2022	6	0.001%	0.0000
4000463308	26356	797	4/28/2022	5/4/2022	6	0.000%	0.0000
4000463310	26639	15,660	4/28/2022	5/4/2022	6	0.004%	0.0002
4000463319	33956	4,692	4/28/2022	5/4/2022	6	0.001%	0.0001
4000463261	4765	8,000	4/28/2022	5/4/2022	6	0.002%	0.0001
4000463263	15871	1,883	4/28/2022	5/4/2022	6	0.000%	0.0000
4000463265	34888	2,305	4/28/2022	5/4/2022	6	0.001%	0.0000
4000463270	104154	352	4/28/2022	5/4/2022	6	0.000%	0.0000
4000463273	116332	6,593	4/28/2022	5/4/2022	6	0.002%	0.0001
4000463276	132094	1,023	4/28/2022	5/4/2022	6	0.000%	0.0000
4000463278	139713	77,190	4/28/2022	5/4/2022	6	0.020%	0.0012
4000463280	143182	25,000	4/28/2022	5/4/2022	6	0.007%	0.0004
4000463282	143463	2,750	4/28/2022	5/4/2022	6	0.001%	0.0000
4000463285	144949	285	4/28/2022	5/4/2022	6	0.000%	0.0000
4000463286	144955	1,924	4/28/2022	5/4/2022	6	0.001%	0.0000
4000463287	144982	44,202	4/28/2022	5/4/2022	6	0.012%	0.0007
4000463458	107191	708	5/3/2022	5/9/2022	6	0.000%	0.0000
4000463533	18267	17,996	5/4/2022	5/10/2022	6	0.005%	0.0003
4000463534	18518	850	5/4/2022	5/10/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463517	27094	7,946	5/4/2022	5/10/2022	6	0.002%	0.0001
4000463519	116332	333,066	5/4/2022	5/10/2022	6	0.088%	0.0053
4000463520	118807	1,949	5/4/2022	5/10/2022	6	0.001%	0.0000
4000463522	126775	1,148	5/4/2022	5/10/2022	6	0.000%	0.0000
4000463528	143920	35	5/4/2022	5/10/2022	6	0.000%	0.0000
4000463572	18267	1,902	5/5/2022	5/11/2022	6	0.001%	0.0000
4000463555	105195	13,473	5/5/2022	5/11/2022	6	0.004%	0.0002
4000463556	108149	91	5/5/2022	5/11/2022	6	0.000%	0.0000
4000463558	116384	147	5/5/2022	5/11/2022	6	0.000%	0.0000
4000463559	118807	233	5/5/2022	5/11/2022	6	0.000%	0.0000
4000463561	135488	36,500	5/5/2022	5/11/2022	6	0.010%	0.0006
4000463564	143436	836	5/5/2022	5/11/2022	6	0.000%	0.0000
4000463565	143577	9,871	5/5/2022	5/11/2022	6	0.003%	0.0002
4000463569	144949	715	5/5/2022	5/11/2022	6	0.000%	0.0000
4000463645	141861	3,200	5/10/2022	5/16/2022	6	0.001%	0.0001
4000463722	26667	439	5/11/2022	5/17/2022	6	0.000%	0.0000
4000463727	34064	363	5/11/2022	5/17/2022	6	0.000%	0.0000
4000463730	124943	1,995	5/11/2022	5/17/2022	6	0.001%	0.0000
4000463692	104261	1,459	5/11/2022	5/17/2022	6	0.000%	0.0000
4000463694	118807	2,190	5/11/2022	5/17/2022	6	0.001%	0.0000
4000463696	125742	18,191	5/11/2022	5/17/2022	6	0.005%	0.0003
4000463699	134862	15,973	5/11/2022	5/17/2022	6	0.004%	0.0003
4000463702	142942	1,409	5/11/2022	5/17/2022	6	0.000%	0.0000
4000463703	143577	10,865	5/11/2022	5/17/2022	6	0.003%	0.0002
4000463741	105195	7,604	5/12/2022	5/18/2022	6	0.002%	0.0001
4000463948	14060	1,145	5/18/2022	5/24/2022	6	0.000%	0.0000
4000463949	18267	6,539	5/18/2022	5/24/2022	6	0.002%	0.0001
4000463969	34064	148	5/18/2022	5/24/2022	6	0.000%	0.0000
4000463927	27094	37,952	5/18/2022	5/24/2022	6	0.010%	0.0006
4000463933	106840	40	5/18/2022	5/24/2022	6	0.000%	0.0000
4000463934	112215	17,896	5/18/2022	5/24/2022	6	0.005%	0.0003
4000463935	112215	5,647	5/18/2022	5/24/2022	6	0.001%	0.0001
4000463936	116332	30,962	5/18/2022	5/24/2022	6	0.008%	0.0005
4000463937	116384	179	5/18/2022	5/24/2022	6	0.000%	0.0000
4000464007	28474	2,404	5/19/2022	5/25/2022	6	0.001%	0.0000
4000464011	34064	125	5/19/2022	5/25/2022	6	0.000%	0.0000
4000463982	100335	3,100	5/19/2022	5/25/2022	6	0.001%	0.0000
4000463985	116332	102,955	5/19/2022	5/25/2022	6	0.027%	0.0016
4000463992	143920	5	5/19/2022	5/25/2022	6	0.000%	0.0000
4000464211	18267	10,369	5/26/2022	6/1/2022	6	0.003%	0.0002
4000464214	25083	3,024	5/26/2022	6/1/2022	6	0.001%	0.0000
4000464228	30475	71,931	5/26/2022	6/1/2022	6	0.019%	0.0011
4000464229	30475	48,740	5/26/2022	6/1/2022	6	0.013%	0.0008
4000464232	32896	897	5/26/2022	6/1/2022	6	0.000%	0.0000
4000464190	135488	22,944	5/26/2022	6/1/2022	6	0.006%	0.0004
4000464191	138862	103	5/26/2022	6/1/2022	6	0.000%	0.0000
4000464393	10384	800	6/1/2022	6/7/2022	6	0.000%	0.0000
4000464401	25173	14,080	6/1/2022	6/7/2022	6	0.004%	0.0002
4000464402	26338	2,837	6/1/2022	6/7/2022	6	0.001%	0.0000
4000464375	32842	1,978	6/1/2022	6/7/2022	6	0.001%	0.0000
4000464377	105195	5,377	6/1/2022	6/7/2022	6	0.001%	0.0001
4000464379	116384	26	6/1/2022	6/7/2022	6	0.000%	0.0000
4000464383	144567	275	6/1/2022	6/7/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464384	144567	468	6/1/2022	6/7/2022	6	0.000%	0.0000
4000464389	145093	1,905	6/1/2022	6/7/2022	6	0.001%	0.0000
4000464390	145128	265	6/1/2022	6/7/2022	6	0.000%	0.0000
4000464487	142298	992	6/3/2022	6/9/2022	6	0.000%	0.0000
4000464640	34064	728	6/8/2022	6/14/2022	6	0.000%	0.0000
4000464613	32842	46	6/8/2022	6/14/2022	6	0.000%	0.0000
4000464615	103392	99	6/8/2022	6/14/2022	6	0.000%	0.0000
4000464628	143312	10,180	6/8/2022	6/14/2022	6	0.003%	0.0002
4000464632	144567	4,758	6/8/2022	6/14/2022	6	0.001%	0.0001
4000464634	145093	2,020	6/8/2022	6/14/2022	6	0.001%	0.0000
4000464650	116384	58	6/9/2022	6/15/2022	6	0.000%	0.0000
4000464655	143340	8,128	6/9/2022	6/15/2022	6	0.002%	0.0001
4000464656	143577	9,755	6/9/2022	6/15/2022	6	0.003%	0.0002
4000464663	144982	17,656	6/9/2022	6/15/2022	6	0.005%	0.0003
4000464872	134862	1,847	6/16/2022	6/22/2022	6	0.000%	0.0000
4000465008	144969	248	6/21/2022	6/27/2022	6	0.000%	0.0000
4000465051	34064	197	6/22/2022	6/28/2022	6	0.000%	0.0000
4000465053	105195	9,638	6/22/2022	6/28/2022	6	0.003%	0.0002
4000465023	105195	1,184	6/22/2022	6/28/2022	6	0.000%	0.0000
4000465024	116384	248	6/22/2022	6/28/2022	6	0.000%	0.0000
4000465029	143659	14,559	6/22/2022	6/28/2022	6	0.004%	0.0002
4000465030	143920	10	6/22/2022	6/28/2022	6	0.000%	0.0000
4000465031	144530	49,455	6/22/2022	6/28/2022	6	0.013%	0.0008
4000465032	144567	1,980	6/22/2022	6/28/2022	6	0.001%	0.0000
4000465087	11305	9,152	6/23/2022	6/29/2022	6	0.002%	0.0001
4000465094	26356	3,874	6/23/2022	6/29/2022	6	0.001%	0.0001
4000465098	28474	915	6/23/2022	6/29/2022	6	0.000%	0.0000
4000465058	4765	13,500	6/23/2022	6/29/2022	6	0.004%	0.0002
4000465064	103291	213,779	6/23/2022	6/29/2022	6	0.056%	0.0034
4000465068	118807	1,763	6/23/2022	6/29/2022	6	0.000%	0.0000
4000465074	137204	12,924	6/23/2022	6/29/2022	6	0.003%	0.0002
4000465079	143463	110,387	6/23/2022	6/29/2022	6	0.029%	0.0017
4000465080	143577	8,045	6/23/2022	6/29/2022	6	0.002%	0.0001
4000465358	13534	9,917	6/30/2022	7/6/2022	6	0.003%	0.0002
4000465363	24281	4,344	6/30/2022	7/6/2022	6	0.001%	0.0001
4000465312	132094	3,245	6/30/2022	7/6/2022	6	0.001%	0.0001
4000465315	135488	28,500	6/30/2022	7/6/2022	6	0.008%	0.0005
4000465334	143312	52,046	6/30/2022	7/6/2022	6	0.014%	0.0008
4000465347	144510	2,000	6/30/2022	7/6/2022	6	0.001%	0.0000
4000465348	144573	4,000	6/30/2022	7/6/2022	6	0.001%	0.0001
4000465474	125742	282	7/5/2022	7/11/2022	6	0.000%	0.0000
4000465521	24281	2,320	7/6/2022	7/12/2022	6	0.001%	0.0000
4000465525	34064	251,355	7/6/2022	7/12/2022	6	0.066%	0.0040
4000465495	4765	25,219	7/6/2022	7/12/2022	6	0.007%	0.0004
4000465497	103392	971	7/6/2022	7/12/2022	6	0.000%	0.0000
4000465499	116384	158	7/6/2022	7/12/2022	6	0.000%	0.0000
4000465500	118807	692	7/6/2022	7/12/2022	6	0.000%	0.0000
4000465515	141101	114,221	7/6/2022	7/12/2022	6	0.030%	0.0018
4000465552	24383	943	7/7/2022	7/13/2022	6	0.000%	0.0000
4000465558	33956	450	7/7/2022	7/13/2022	6	0.000%	0.0000
4000465559	34064	197	7/7/2022	7/13/2022	6	0.000%	0.0000
4000465539	116384	56	7/7/2022	7/13/2022	6	0.000%	0.0000
4000465540	125742	10,068	7/7/2022	7/13/2022	6	0.003%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465541	135488	14,340	7/7/2022	7/13/2022	6	0.004%	0.0002
4000465546	143577	3,904	7/7/2022	7/13/2022	6	0.001%	0.0001
4000465547	144816	5,258	7/7/2022	7/13/2022	6	0.001%	0.0001
4000465548	145137	850	7/7/2022	7/13/2022	6	0.000%	0.0000
4000465720	141114	6,314	7/12/2022	7/18/2022	6	0.002%	0.0001
4000465765	30475	7,053	7/13/2022	7/19/2022	6	0.002%	0.0001
4000465769	34341	7,700	7/13/2022	7/19/2022	6	0.002%	0.0001
4000465774	134272	11,882	7/13/2022	7/19/2022	6	0.003%	0.0002
4000465738	32842	1,699	7/13/2022	7/19/2022	6	0.000%	0.0000
4000465741	102637	168	7/13/2022	7/19/2022	6	0.000%	0.0000
4000465743	105195	6,736	7/13/2022	7/19/2022	6	0.002%	0.0001
4000465745	116384	415	7/13/2022	7/19/2022	6	0.000%	0.0000
4000465746	118807	142	7/13/2022	7/19/2022	6	0.000%	0.0000
4000465753	143577	6,154	7/13/2022	7/19/2022	6	0.002%	0.0001
4000465755	144530	15,992	7/13/2022	7/19/2022	6	0.004%	0.0003
4000465756	144567	10,533	7/13/2022	7/19/2022	6	0.003%	0.0002
4000465794	18267	6,710	7/14/2022	7/20/2022	6	0.002%	0.0001
4000465796	25083	5,775	7/14/2022	7/20/2022	6	0.002%	0.0001
4000465801	26667	1,026	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465808	34064	27	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465778	112215	6,508	7/14/2022	7/20/2022	6	0.002%	0.0001
4000465779	116384	589	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465780	118807	1,136	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465783	135488	97	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465785	138862	47	7/14/2022	7/20/2022	6	0.000%	0.0000
4000465790	144567	6,115	7/14/2022	7/20/2022	6	0.002%	0.0001
4000465791	144567	13,604	7/14/2022	7/20/2022	6	0.004%	0.0002
4000465792	144816	2,111	7/14/2022	7/20/2022	6	0.001%	0.0000
4000465898	142635	21,769	7/19/2022	7/25/2022	6	0.006%	0.0003
4000465979	34064	395	7/20/2022	7/26/2022	6	0.000%	0.0000
4000465946	116051	2,308	7/20/2022	7/26/2022	6	0.001%	0.0000
4000465951	132094	100	7/20/2022	7/26/2022	6	0.000%	0.0000
4000465952	141101	38,648	7/20/2022	7/26/2022	6	0.010%	0.0006
4000465956	143312	29,725	7/20/2022	7/26/2022	6	0.008%	0.0005
4000465959	143606	871	7/20/2022	7/26/2022	6	0.000%	0.0000
4000465963	144567	15,220	7/20/2022	7/26/2022	6	0.004%	0.0002
4000466019	33956	450	7/21/2022	7/27/2022	6	0.000%	0.0000
4000465996	142942	5,358	7/21/2022	7/27/2022	6	0.001%	0.0001
4000466002	144816	1,255	7/21/2022	7/27/2022	6	0.000%	0.0000
4000466003	144949	199	7/21/2022	7/27/2022	6	0.000%	0.0000
4000466170	116384	56	7/27/2022	8/2/2022	6	0.000%	0.0000
4000466177	143011	4,415	7/27/2022	8/2/2022	6	0.001%	0.0001
4000466449	112215	480	8/3/2022	8/9/2022	6	0.000%	0.0000
4000466450	116384	111	8/3/2022	8/9/2022	6	0.000%	0.0000
4000466461	143694	800	8/3/2022	8/9/2022	6	0.000%	0.0000
4000466658	129031	2,701	8/10/2022	8/16/2022	6	0.001%	0.0000
4000466672	143637	3,750	8/10/2022	8/16/2022	6	0.001%	0.0001
4000466906	112215	3,432	8/17/2022	8/23/2022	6	0.001%	0.0001
4000466913	141101	35,086	8/17/2022	8/23/2022	6	0.009%	0.0006
4000467050	33036	24,089	8/19/2022	8/25/2022	6	0.006%	0.0004
4000467052	33049	7,243	8/19/2022	8/25/2022	6	0.002%	0.0001
4000467054	33068	5,364	8/19/2022	8/25/2022	6	0.001%	0.0001
4000467120	116384	18	8/24/2022	8/30/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467159	108092	1,489	8/25/2022	8/31/2022	6	0.000%	0.0000
4000467162	112215	3,786	8/25/2022	8/31/2022	6	0.001%	0.0001
4000467163	112215	8,390	8/25/2022	8/31/2022	6	0.002%	0.0001
4000467164	116384	818	8/25/2022	8/31/2022	6	0.000%	0.0000
4000467166	125742	4,200	8/25/2022	8/31/2022	6	0.001%	0.0001
4000467171	142942	912	8/25/2022	8/31/2022	6	0.000%	0.0000
4000467174	144097	937,954	8/25/2022	8/31/2022	6	0.247%	0.0148
4000467404	112215	2,580	9/1/2022	9/7/2022	6	0.001%	0.0000
4000467412	143011	12,509	9/1/2022	9/7/2022	6	0.003%	0.0002
4000467584	34341	7,700	9/7/2022	9/13/2022	6	0.002%	0.0001
4000467570	116384	485	9/7/2022	9/13/2022	6	0.000%	0.0000
4000467572	125742	1,926	9/7/2022	9/13/2022	6	0.001%	0.0000
4000467573	138494	125	9/7/2022	9/13/2022	6	0.000%	0.0000
4000467594	116384	4	9/8/2022	9/14/2022	6	0.000%	0.0000
4000467696	143072	1,547	9/13/2022	9/19/2022	6	0.000%	0.0000
4000467730	129859	76,650	9/14/2022	9/20/2022	6	0.020%	0.0012
4000467734	141101	25,515	9/14/2022	9/20/2022	6	0.007%	0.0004
4000467737	143485	139,758	9/14/2022	9/20/2022	6	0.037%	0.0022
4000467792	112215	189	9/15/2022	9/21/2022	6	0.000%	0.0000
4000467805	142587	419	9/15/2022	9/21/2022	6	0.000%	0.0000
4000467809	144912	230,000	9/15/2022	9/21/2022	6	0.061%	0.0036
4000467968	143694	642	9/21/2022	9/27/2022	6	0.000%	0.0000
4000468022	34341	6,600	9/22/2022	9/28/2022	6	0.002%	0.0001
4000468001	142942	960	9/22/2022	9/28/2022	6	0.000%	0.0000
4000468006	144760	769	9/22/2022	9/28/2022	6	0.000%	0.0000
4000468216	116384	16	9/28/2022	10/4/2022	6	0.000%	0.0000
4000468270	116384	57	9/29/2022	10/5/2022	6	0.000%	0.0000
4000468277	143011	2,833	9/29/2022	10/5/2022	6	0.001%	0.0000
4000468279	143577	7,635	9/29/2022	10/5/2022	6	0.002%	0.0001
4000468672	133795	11,499	10/11/2022	10/17/2022	6	0.003%	0.0002
4000468691	116384	341	10/12/2022	10/18/2022	6	0.000%	0.0000
4000468712	143485	139,545	10/12/2022	10/18/2022	6	0.037%	0.0022
4000468745	26996	10,800	10/13/2022	10/19/2022	6	0.003%	0.0002
4000468944	141101	42,136	10/19/2022	10/25/2022	6	0.011%	0.0007
4000469068	34341	6,600	10/20/2022	10/26/2022	6	0.002%	0.0001
4000469048	141858	2,560	10/20/2022	10/26/2022	6	0.001%	0.0000
4000469225	142942	1,086	10/26/2022	11/1/2022	6	0.000%	0.0000
4000469282	142613	23,035	10/27/2022	11/2/2022	6	0.006%	0.0004
4000469287	143577	7,318	10/27/2022	11/2/2022	6	0.002%	0.0001
4000469289	144949	54	10/27/2022	11/2/2022	6	0.000%	0.0000
4000469505	141822	8,480	11/2/2022	11/8/2022	6	0.002%	0.0001
4000469525	144982	431	11/2/2022	11/8/2022	6	0.000%	0.0000
4000469594	34112	4,162	11/3/2022	11/9/2022	6	0.001%	0.0001
4000469553	100577	195	11/3/2022	11/9/2022	6	0.000%	0.0000
4000469566	143072	21,174	11/3/2022	11/9/2022	6	0.006%	0.0003
4000469719	123388	231	11/9/2022	11/15/2022	6	0.000%	0.0000
4000469912	141101	38,362	11/16/2022	11/22/2022	6	0.010%	0.0006
4000469990	34341	6,600	11/17/2022	11/23/2022	6	0.002%	0.0001
4000470335	143785	14,151	11/30/2022	12/6/2022	6	0.004%	0.0002
4000470409	130634	17,219	12/1/2022	12/7/2022	6	0.005%	0.0003
4000470412	133414	226	12/1/2022	12/7/2022	6	0.000%	0.0000
4000470425	143694	13,096	12/1/2022	12/7/2022	6	0.003%	0.0002
4000470631	18267	815	12/7/2022	12/13/2022	6	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470640	26642	3,990	12/7/2022	12/13/2022	6	0.001%	0.0001
4000470645	105195	1,063	12/7/2022	12/13/2022	6	0.000%	0.0000
4000470613	133414	716	12/7/2022	12/13/2022	6	0.000%	0.0000
4000470621	142942	1,792	12/7/2022	12/13/2022	6	0.000%	0.0000
4000470668	144982	26,578	12/8/2022	12/14/2022	6	0.007%	0.0004
4000470914	34341	6,600	12/15/2022	12/21/2022	6	0.002%	0.0001
4000470878	36403	483	12/15/2022	12/21/2022	6	0.000%	0.0000
4000470893	141114	1,633	12/15/2022	12/21/2022	6	0.000%	0.0000
4000471308	112215	880	12/28/2022	1/3/2023	6	0.000%	0.0000
4000459589	33770	67,312	1/5/2022	1/12/2022	7	0.018%	0.0012
4000459593	112215	19,140	1/5/2022	1/12/2022	7	0.005%	0.0004
4000459608	33770	63,024	1/6/2022	1/13/2022	7	0.017%	0.0012
4000459617	112215	332	1/6/2022	1/13/2022	7	0.000%	0.0000
4000459618	116332	265,347	1/6/2022	1/13/2022	7	0.070%	0.0049
4000459787	10384	7,600	1/12/2022	1/19/2022	7	0.002%	0.0001
4000459791	24383	733	1/12/2022	1/19/2022	7	0.000%	0.0000
4000459801	34064	1,194	1/12/2022	1/19/2022	7	0.000%	0.0000
4000459802	34341	6,300	1/12/2022	1/19/2022	7	0.002%	0.0001
4000459785	144084	2,500	1/12/2022	1/19/2022	7	0.001%	0.0000
4000459985	11305	12,962	1/18/2022	1/25/2022	7	0.003%	0.0002
4000459993	24281	24,461	1/18/2022	1/25/2022	7	0.006%	0.0005
4000460001	30257	119,764	1/18/2022	1/25/2022	7	0.032%	0.0022
4000460006	34064	125	1/18/2022	1/25/2022	7	0.000%	0.0000
4000459964	118807	403	1/18/2022	1/25/2022	7	0.000%	0.0000
4000459965	134664	764	1/18/2022	1/25/2022	7	0.000%	0.0000
4000459966	134664	246,695	1/18/2022	1/25/2022	7	0.065%	0.0046
4000459968	141101	49,547	1/18/2022	1/25/2022	7	0.013%	0.0009
4000459971	143312	26,724	1/18/2022	1/25/2022	7	0.007%	0.0005
4000459972	143338	67,991	1/18/2022	1/25/2022	7	0.018%	0.0013
4000459973	143463	24,600	1/18/2022	1/25/2022	7	0.006%	0.0005
4000459976	144567	4,965	1/18/2022	1/25/2022	7	0.001%	0.0001
4000459977	144567	24,870	1/18/2022	1/25/2022	7	0.007%	0.0005
4000460038	25716	26,835	1/19/2022	1/26/2022	7	0.007%	0.0005
4000460039	27013	3,658	1/19/2022	1/26/2022	7	0.001%	0.0001
4000460043	32896	1,800	1/19/2022	1/26/2022	7	0.000%	0.0000
4000460015	15871	8,595	1/19/2022	1/26/2022	7	0.002%	0.0002
4000460082	18267	1,402	1/20/2022	1/27/2022	7	0.000%	0.0000
4000460087	27013	19,606	1/20/2022	1/27/2022	7	0.005%	0.0004
4000460096	33975	3,514	1/20/2022	1/27/2022	7	0.001%	0.0001
4000460098	34341	6,300	1/20/2022	1/27/2022	7	0.002%	0.0001
4000460099	105195	30,073	1/20/2022	1/27/2022	7	0.008%	0.0006
4000460064	105195	10,212	1/20/2022	1/27/2022	7	0.003%	0.0002
4000460066	112215	918	1/20/2022	1/27/2022	7	0.000%	0.0000
4000460077	144097	525,613	1/20/2022	1/27/2022	7	0.139%	0.0097
4000460078	144663	18,800	1/20/2022	1/27/2022	7	0.005%	0.0003
4000460079	144691	6,954	1/20/2022	1/27/2022	7	0.002%	0.0001
4000460129	138240	1,500	1/24/2022	1/31/2022	7	0.000%	0.0000
4000460272	124943	1,093	1/25/2022	2/1/2022	7	0.000%	0.0000
4000460230	102391	761,863	1/25/2022	2/1/2022	7	0.201%	0.0141
4000460240	134664	497	1/25/2022	2/1/2022	7	0.000%	0.0000
4000460241	140438	28,847	1/25/2022	2/1/2022	7	0.008%	0.0005
4000460293	18267	5,460	1/26/2022	2/2/2022	7	0.001%	0.0001
4000460303	34658	4,320	1/26/2022	2/2/2022	7	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460304	105195	1,161	1/26/2022	2/2/2022	7	0.000%	0.0000
4000460280	125742	22,500	1/26/2022	2/2/2022	7	0.006%	0.0004
4000460289	144663	76,800	1/26/2022	2/2/2022	7	0.020%	0.0014
4000460426	14060	10,627	1/27/2022	2/3/2022	7	0.003%	0.0002
4000460427	18267	8,165	1/27/2022	2/3/2022	7	0.002%	0.0002
4000460444	105195	1,512	1/27/2022	2/3/2022	7	0.000%	0.0000
4000460309	10055	54,284	1/27/2022	2/3/2022	7	0.014%	0.0010
4000460311	11857	78,045	1/27/2022	2/3/2022	7	0.021%	0.0014
4000460312	12081	2,458	1/27/2022	2/3/2022	7	0.001%	0.0000
4000460320	105195	13,758	1/27/2022	2/3/2022	7	0.004%	0.0003
4000460322	112215	16,055	1/27/2022	2/3/2022	7	0.004%	0.0003
4000460323	116332	168,909	1/27/2022	2/3/2022	7	0.045%	0.0031
4000460335	143584	49,517	1/27/2022	2/3/2022	7	0.013%	0.0009
4000460337	143991	21,863	1/27/2022	2/3/2022	7	0.006%	0.0004
4000460360	33075	41,582	1/27/2022	2/3/2022	7	0.011%	0.0008
4000460365	33081	8,506	1/27/2022	2/3/2022	7	0.002%	0.0002
4000460490	33016	55,106	1/28/2022	2/4/2022	7	0.015%	0.0010
4000460496	33070	17,355	1/28/2022	2/4/2022	7	0.005%	0.0003
4000460497	33071	170,948	1/28/2022	2/4/2022	7	0.045%	0.0032
4000460499	33073	2,349	1/28/2022	2/4/2022	7	0.001%	0.0000
4000460507	33083	55,642	1/28/2022	2/4/2022	7	0.015%	0.0010
4000460508	33084	1,307	1/28/2022	2/4/2022	7	0.000%	0.0000
4000460510	33090	11,693	1/28/2022	2/4/2022	7	0.003%	0.0002
4000460511	33092	10,977	1/28/2022	2/4/2022	7	0.003%	0.0002
4000460513	33094	4,517	1/28/2022	2/4/2022	7	0.001%	0.0001
4000460515	33096	8,776	1/28/2022	2/4/2022	7	0.002%	0.0002
4000460516	33098	37,084	1/28/2022	2/4/2022	7	0.010%	0.0007
4000460529	33116	3,350	1/28/2022	2/4/2022	7	0.001%	0.0001
4000460530	33117	49,063	1/28/2022	2/4/2022	7	0.013%	0.0009
4000460531	33119	5,779	1/28/2022	2/4/2022	7	0.002%	0.0001
4000460532	33120	44,563	1/28/2022	2/4/2022	7	0.012%	0.0008
4000460533	33121	2,449	1/28/2022	2/4/2022	7	0.001%	0.0000
4000460534	33122	21,585	1/28/2022	2/4/2022	7	0.006%	0.0004
4000460535	33123	778	1/28/2022	2/4/2022	7	0.000%	0.0000
4000460536	33125	3,027	1/28/2022	2/4/2022	7	0.001%	0.0001
4000460542	33131	40,775	1/28/2022	2/4/2022	7	0.011%	0.0008
4000460546	33135	7,535	1/28/2022	2/4/2022	7	0.002%	0.0001
4000460556	33146	10,049	1/28/2022	2/4/2022	7	0.003%	0.0002
4000460558	33148	1,967	1/28/2022	2/4/2022	7	0.001%	0.0000
4000460594	25173	1,815	1/31/2022	2/7/2022	7	0.000%	0.0000
4000460640	141822	8,319	2/1/2022	2/8/2022	7	0.002%	0.0002
4000460641	141831	11,647	2/1/2022	2/8/2022	7	0.003%	0.0002
4000460642	141873	22,938	2/1/2022	2/8/2022	7	0.006%	0.0004
4000460645	142162	11,000	2/1/2022	2/8/2022	7	0.003%	0.0002
4000460653	142942	86,144	2/1/2022	2/8/2022	7	0.023%	0.0016
4000460661	144567	2,800	2/1/2022	2/8/2022	7	0.001%	0.0001
4000460719	117331	3,300	2/2/2022	2/9/2022	7	0.001%	0.0001
4000460678	32842	10,000	2/2/2022	2/9/2022	7	0.003%	0.0002
4000460684	116384	356	2/2/2022	2/9/2022	7	0.000%	0.0000
4000460685	118807	1,731	2/2/2022	2/9/2022	7	0.000%	0.0000
4000460746	26363	1,377	2/3/2022	2/10/2022	7	0.000%	0.0000
4000460752	27552	9,100	2/3/2022	2/10/2022	7	0.002%	0.0002
4000460753	27636	26,000	2/3/2022	2/10/2022	7	0.007%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460755	28084	8,408	2/3/2022	2/10/2022	7	0.002%	0.0002
4000460756	28530	30,729	2/3/2022	2/10/2022	7	0.008%	0.0006
4000460760	124943	570	2/3/2022	2/10/2022	7	0.000%	0.0000
4000460816	124744	1,132	2/7/2022	2/14/2022	7	0.000%	0.0000
4000460821	141158	1,710	2/7/2022	2/14/2022	7	0.000%	0.0000
4000460854	32842	2,000	2/8/2022	2/15/2022	7	0.001%	0.0000
4000460857	116384	301	2/8/2022	2/15/2022	7	0.000%	0.0000
4000460859	124746	1,031	2/8/2022	2/15/2022	7	0.000%	0.0000
4000460864	129118	1,828	2/8/2022	2/15/2022	7	0.000%	0.0000
4000460867	133455	1,625	2/8/2022	2/15/2022	7	0.000%	0.0000
4000460901	10630	2,480	2/9/2022	2/16/2022	7	0.001%	0.0000
4000460908	25808	1,680	2/9/2022	2/16/2022	7	0.000%	0.0000
4000460909	26668	2,126	2/9/2022	2/16/2022	7	0.001%	0.0000
4000460915	30475	9,685	2/9/2022	2/16/2022	7	0.003%	0.0002
4000460921	34937	12,000	2/9/2022	2/16/2022	7	0.003%	0.0002
4000460886	15871	75	2/9/2022	2/16/2022	7	0.000%	0.0000
4000460887	103392	232	2/9/2022	2/16/2022	7	0.000%	0.0000
4000460892	141101	26,762	2/9/2022	2/16/2022	7	0.007%	0.0005
4000460959	25599	2,253	2/10/2022	2/17/2022	7	0.001%	0.0000
4000460964	26659	7,979	2/10/2022	2/17/2022	7	0.002%	0.0001
4000460965	27013	326	2/10/2022	2/17/2022	7	0.000%	0.0000
4000460967	28084	2,470	2/10/2022	2/17/2022	7	0.001%	0.0000
4000460970	33747	1,506	2/10/2022	2/17/2022	7	0.000%	0.0000
4000460938	104261	1,231	2/10/2022	2/17/2022	7	0.000%	0.0000
4000460979	103925	3,684	2/11/2022	2/18/2022	7	0.001%	0.0001
4000461155	34064	136	2/16/2022	2/23/2022	7	0.000%	0.0000
4000461156	105195	3,226	2/16/2022	2/23/2022	7	0.001%	0.0001
4000461104	31692	20,499	2/16/2022	2/23/2022	7	0.005%	0.0004
4000461110	107325	750	2/16/2022	2/23/2022	7	0.000%	0.0000
4000461125	132094	93,150	2/16/2022	2/23/2022	7	0.025%	0.0017
4000461137	143577	9,760	2/16/2022	2/23/2022	7	0.003%	0.0002
4000461141	116971	3,000	2/16/2022	2/23/2022	7	0.001%	0.0001
4000461186	14060	3,825	2/17/2022	2/24/2022	7	0.001%	0.0001
4000461187	18267	8,219	2/17/2022	2/24/2022	7	0.002%	0.0002
4000461190	24383	575	2/17/2022	2/24/2022	7	0.000%	0.0000
4000461202	32853	270	2/17/2022	2/24/2022	7	0.000%	0.0000
4000461204	34341	10,500	2/17/2022	2/24/2022	7	0.003%	0.0002
4000461166	28737	2,500	2/17/2022	2/24/2022	7	0.001%	0.0000
4000461168	101283	6,456	2/17/2022	2/24/2022	7	0.002%	0.0001
4000461170	116384	168	2/17/2022	2/24/2022	7	0.000%	0.0000
4000461306	28474	673	2/22/2022	3/1/2022	7	0.000%	0.0000
4000461311	105195	18,047	2/22/2022	3/1/2022	7	0.005%	0.0003
4000461272	116384	17	2/22/2022	3/1/2022	7	0.000%	0.0000
4000461273	118807	82	2/22/2022	3/1/2022	7	0.000%	0.0000
4000461277	126177	25,000	2/22/2022	3/1/2022	7	0.007%	0.0005
4000461282	131493	10,000	2/22/2022	3/1/2022	7	0.003%	0.0002
4000461283	132094	1,210	2/22/2022	3/1/2022	7	0.000%	0.0000
4000461285	138981	1,400	2/22/2022	3/1/2022	7	0.000%	0.0000
4000461289	143321	22,000	2/22/2022	3/1/2022	7	0.006%	0.0004
4000461293	144567	3,026	2/22/2022	3/1/2022	7	0.001%	0.0001
4000461341	11305	3,310	2/23/2022	3/2/2022	7	0.001%	0.0001
4000461349	26207	22,100	2/23/2022	3/2/2022	7	0.006%	0.0004
4000461363	30257	84,402	2/23/2022	3/2/2022	7	0.022%	0.0016

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461365	117331	100,800	2/23/2022	3/2/2022	7	0.027%	0.0019
4000461366	117331	101,850	2/23/2022	3/2/2022	7	0.027%	0.0019
4000461312	4765	3,590	2/23/2022	3/2/2022	7	0.001%	0.0001
4000461314	15871	709	2/23/2022	3/2/2022	7	0.000%	0.0000
4000461316	21678	207,432	2/23/2022	3/2/2022	7	0.055%	0.0038
4000461317	27094	10,879	2/23/2022	3/2/2022	7	0.003%	0.0002
4000461321	116051	125	2/23/2022	3/2/2022	7	0.000%	0.0000
4000461332	139733	566	2/23/2022	3/2/2022	7	0.000%	0.0000
4000461393	24765	107,592	2/24/2022	3/3/2022	7	0.028%	0.0020
4000461398	27013	5,225	2/24/2022	3/3/2022	7	0.001%	0.0001
4000461400	28484	4,800	2/24/2022	3/3/2022	7	0.001%	0.0001
4000461401	28530	15,912	2/24/2022	3/3/2022	7	0.004%	0.0003
4000461404	124943	713	2/24/2022	3/3/2022	7	0.000%	0.0000
4000461370	7529	17,790	2/24/2022	3/3/2022	7	0.005%	0.0003
4000461372	15871	561	2/24/2022	3/3/2022	7	0.000%	0.0000
4000461375	116384	190	2/24/2022	3/3/2022	7	0.000%	0.0000
4000461376	118807	31	2/24/2022	3/3/2022	7	0.000%	0.0000
4000461382	143577	11,527	2/24/2022	3/3/2022	7	0.003%	0.0002
4000461486	129204	1,732	2/28/2022	3/7/2022	7	0.000%	0.0000
4000461599	33956	6,938	3/2/2022	3/9/2022	7	0.002%	0.0001
4000461547	116384	130	3/2/2022	3/9/2022	7	0.000%	0.0000
4000461560	141370	13,250	3/2/2022	3/9/2022	7	0.003%	0.0002
4000461561	141822	8,319	3/2/2022	3/9/2022	7	0.002%	0.0002
4000461573	143312	58,417	3/2/2022	3/9/2022	7	0.015%	0.0011
4000461574	143364	12,300	3/2/2022	3/9/2022	7	0.003%	0.0002
4000461576	143463	29,520	3/2/2022	3/9/2022	7	0.008%	0.0005
4000461707	17293	17,500	3/8/2022	3/15/2022	7	0.005%	0.0003
4000461716	116384	781	3/8/2022	3/15/2022	7	0.000%	0.0000
4000461717	118807	428	3/8/2022	3/15/2022	7	0.000%	0.0000
4000461722	143920	3,501	3/8/2022	3/15/2022	7	0.001%	0.0001
4000461753	9121	400	3/9/2022	3/16/2022	7	0.000%	0.0000
4000461755	26659	2,077	3/9/2022	3/16/2022	7	0.001%	0.0000
4000461756	30475	74,194	3/9/2022	3/16/2022	7	0.020%	0.0014
4000461757	30475	94,810	3/9/2022	3/16/2022	7	0.025%	0.0018
4000461758	30475	102,522	3/9/2022	3/16/2022	7	0.027%	0.0019
4000461759	105195	780	3/9/2022	3/16/2022	7	0.000%	0.0000
4000461739	27094	3,667	3/9/2022	3/16/2022	7	0.001%	0.0001
4000461751	144173	16,363	3/9/2022	3/16/2022	7	0.004%	0.0003
4000461787	14463	59,222	3/10/2022	3/17/2022	7	0.016%	0.0011
4000461791	26604	895	3/10/2022	3/17/2022	7	0.000%	0.0000
4000461793	26659	4,613	3/10/2022	3/17/2022	7	0.001%	0.0001
4000461794	26679	5,313	3/10/2022	3/17/2022	7	0.001%	0.0001
4000461796	27482	990	3/10/2022	3/17/2022	7	0.000%	0.0000
4000461797	28084	4,180	3/10/2022	3/17/2022	7	0.001%	0.0001
4000461798	28530	20,327	3/10/2022	3/17/2022	7	0.005%	0.0004
4000461802	32808	3,410	3/10/2022	3/17/2022	7	0.001%	0.0001
4000461803	32853	450	3/10/2022	3/17/2022	7	0.000%	0.0000
4000461765	10384	9,200	3/10/2022	3/17/2022	7	0.002%	0.0002
4000461775	142635	45,680	3/10/2022	3/17/2022	7	0.012%	0.0008
4000461819	112215	2,784	3/11/2022	3/18/2022	7	0.001%	0.0001
4000461820	116332	153,749	3/11/2022	3/18/2022	7	0.041%	0.0028
4000461859	121853	2,510	3/14/2022	3/21/2022	7	0.001%	0.0000
4000461863	130164	1,727	3/14/2022	3/21/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461922	34064	236	3/15/2022	3/22/2022	7	0.000%	0.0000
4000461885	116384	164	3/15/2022	3/22/2022	7	0.000%	0.0000
4000461888	126775	552	3/15/2022	3/22/2022	7	0.000%	0.0000
4000461943	14060	900	3/16/2022	3/23/2022	7	0.000%	0.0000
4000461947	24383	3,923	3/16/2022	3/23/2022	7	0.001%	0.0001
4000461948	24999	2,120	3/16/2022	3/23/2022	7	0.001%	0.0000
4000461952	27068	7,524	3/16/2022	3/23/2022	7	0.002%	0.0001
4000461954	30475	201,526	3/16/2022	3/23/2022	7	0.053%	0.0037
4000461927	24765	2,850	3/16/2022	3/23/2022	7	0.001%	0.0001
4000461931	118807	407	3/16/2022	3/23/2022	7	0.000%	0.0000
4000461987	11474	4,175	3/17/2022	3/24/2022	7	0.001%	0.0001
4000461989	26588	420	3/17/2022	3/24/2022	7	0.000%	0.0000
4000461993	29919	5,575	3/17/2022	3/24/2022	7	0.001%	0.0001
4000461960	10384	11,000	3/17/2022	3/24/2022	7	0.003%	0.0002
4000461961	15871	3,080	3/17/2022	3/24/2022	7	0.001%	0.0001
4000461966	103867	7	3/17/2022	3/24/2022	7	0.000%	0.0000
4000461968	112215	5,440	3/17/2022	3/24/2022	7	0.001%	0.0001
4000461969	116051	500	3/17/2022	3/24/2022	7	0.000%	0.0000
4000461974	133414	3,134	3/17/2022	3/24/2022	7	0.001%	0.0001
4000461977	139733	1,188	3/17/2022	3/24/2022	7	0.000%	0.0000
4000462013	112215	3,432	3/18/2022	3/25/2022	7	0.001%	0.0001
4000462014	112215	3,344	3/18/2022	3/25/2022	7	0.001%	0.0001
4000462074	137204	4,294	3/21/2022	3/28/2022	7	0.001%	0.0001
4000462115	3970	1,670	3/22/2022	3/29/2022	7	0.000%	0.0000
4000462118	22227	1,521	3/22/2022	3/29/2022	7	0.000%	0.0000
4000462126	143659	18,800	3/22/2022	3/29/2022	7	0.005%	0.0003
4000462160	27068	11,742	3/23/2022	3/30/2022	7	0.003%	0.0002
4000462165	105195	6,231	3/23/2022	3/30/2022	7	0.002%	0.0001
4000462142	105195	1,510	3/23/2022	3/30/2022	7	0.000%	0.0000
4000462153	143637	3,750	3/23/2022	3/30/2022	7	0.001%	0.0001
4000462191	30475	35,133	3/24/2022	3/31/2022	7	0.009%	0.0006
4000462174	117392	4,180	3/24/2022	3/31/2022	7	0.001%	0.0001
4000462182	144097	804,556	3/24/2022	3/31/2022	7	0.212%	0.0149
4000462183	144567	540	3/24/2022	3/31/2022	7	0.000%	0.0000
4000462208	116332	150,847	3/25/2022	4/1/2022	7	0.040%	0.0028
4000462214	139713	171,470	3/25/2022	4/1/2022	7	0.045%	0.0032
4000462262	25173	4,180	3/28/2022	4/4/2022	7	0.001%	0.0001
4000462307	26356	3,165	3/29/2022	4/5/2022	7	0.001%	0.0001
4000462310	26604	655	3/29/2022	4/5/2022	7	0.000%	0.0000
4000462284	25623	3,179	3/29/2022	4/5/2022	7	0.001%	0.0001
4000462285	27094	6,180	3/29/2022	4/5/2022	7	0.002%	0.0001
4000462286	32842	1,588	3/29/2022	4/5/2022	7	0.000%	0.0000
4000462288	116051	2,682	3/29/2022	4/5/2022	7	0.001%	0.0000
4000462289	116384	75	3/29/2022	4/5/2022	7	0.000%	0.0000
4000462290	118807	2,292	3/29/2022	4/5/2022	7	0.001%	0.0000
4000462293	132094	137	3/29/2022	4/5/2022	7	0.000%	0.0000
4000462382	24383	380	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462394	30475	35,492	3/30/2022	4/6/2022	7	0.009%	0.0007
4000462395	30475	17,259	3/30/2022	4/6/2022	7	0.005%	0.0003
4000462396	30475	20,927	3/30/2022	4/6/2022	7	0.006%	0.0004
4000462397	30475	22,397	3/30/2022	4/6/2022	7	0.006%	0.0004
4000462399	33354	371,744	3/30/2022	4/6/2022	7	0.098%	0.0069
4000462400	34064	618	3/30/2022	4/6/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462402	34658	3,200	3/30/2022	4/6/2022	7	0.001%	0.0001
4000462403	34937	12,000	3/30/2022	4/6/2022	7	0.003%	0.0002
4000462404	117331	55,450	3/30/2022	4/6/2022	7	0.015%	0.0010
4000462322	15871	1,178	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462323	24765	127,008	3/30/2022	4/6/2022	7	0.033%	0.0023
4000462330	107593	2,500	3/30/2022	4/6/2022	7	0.001%	0.0000
4000462331	108420	5,000	3/30/2022	4/6/2022	7	0.001%	0.0001
4000462332	109715	25,000	3/30/2022	4/6/2022	7	0.007%	0.0005
4000462333	112103	36,138	3/30/2022	4/6/2022	7	0.010%	0.0007
4000462334	112103	442,492	3/30/2022	4/6/2022	7	0.117%	0.0082
4000462335	112215	1,290	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462336	115761	45	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462341	118807	303	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462351	133414	20,621	3/30/2022	4/6/2022	7	0.005%	0.0004
4000462358	141995	1,000	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462362	143312	18,605	3/30/2022	4/6/2022	7	0.005%	0.0003
4000462363	143340	64,688	3/30/2022	4/6/2022	7	0.017%	0.0012
4000462365	143463	218,429	3/30/2022	4/6/2022	7	0.058%	0.0040
4000462368	143606	58,940	3/30/2022	4/6/2022	7	0.016%	0.0011
4000462371	144460	1,000	3/30/2022	4/6/2022	7	0.000%	0.0000
4000462434	11260	1,857	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462437	11577	3,833	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462440	25659	973	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462441	25708	6,347	3/31/2022	4/7/2022	7	0.002%	0.0001
4000462447	26604	655	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462448	26642	4,560	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462449	26679	1,750	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462451	27636	3,300	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462454	28084	26,695	3/31/2022	4/7/2022	7	0.007%	0.0005
4000462459	32875	3,000	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462460	33238	525	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462409	26958	3,199	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462417	129387	39,003	3/31/2022	4/7/2022	7	0.010%	0.0007
4000462418	129859	356,330	3/31/2022	4/7/2022	7	0.094%	0.0066
4000462420	139713	38,595	3/31/2022	4/7/2022	7	0.010%	0.0007
4000462421	140752	775	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462424	143436	836	3/31/2022	4/7/2022	7	0.000%	0.0000
4000462428	144097	2,846,858	3/31/2022	4/7/2022	7	0.751%	0.0526
4000462430	144546	4,900	3/31/2022	4/7/2022	7	0.001%	0.0001
4000462431	144567	2,163	3/31/2022	4/7/2022	7	0.001%	0.0000
4000462481	103291	27,926	4/1/2022	4/8/2022	7	0.007%	0.0005
4000462568	142787	10,258	4/4/2022	4/11/2022	7	0.003%	0.0002
4000462614	18267	1,773	4/5/2022	4/12/2022	7	0.000%	0.0000
4000462601	116384	174	4/5/2022	4/12/2022	7	0.000%	0.0000
4000462603	125742	2,241	4/5/2022	4/12/2022	7	0.001%	0.0000
4000462607	142607	2,500	4/5/2022	4/12/2022	7	0.001%	0.0000
4000462611	144773	625	4/5/2022	4/12/2022	7	0.000%	0.0000
4000462638	26655	1,488	4/6/2022	4/13/2022	7	0.000%	0.0000
4000462617	15871	1,121	4/6/2022	4/13/2022	7	0.000%	0.0000
4000462622	118807	30	4/6/2022	4/13/2022	7	0.000%	0.0000
4000462678	25708	3,231	4/7/2022	4/14/2022	7	0.001%	0.0001
4000462679	26604	975	4/7/2022	4/14/2022	7	0.000%	0.0000
4000462680	27962	2,679	4/7/2022	4/14/2022	7	0.001%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462681	28530	20,737	4/7/2022	4/14/2022	7	0.005%	0.0004
4000462649	103392	358	4/7/2022	4/14/2022	7	0.000%	0.0000
4000462650	112215	2,865	4/7/2022	4/14/2022	7	0.001%	0.0001
4000462652	116850	1,195	4/7/2022	4/14/2022	7	0.000%	0.0000
4000462660	139713	38,595	4/7/2022	4/14/2022	7	0.010%	0.0007
4000462663	143340	723	4/7/2022	4/14/2022	7	0.000%	0.0000
4000462665	143753	125,632	4/7/2022	4/14/2022	7	0.033%	0.0023
4000462670	144955	781	4/7/2022	4/14/2022	7	0.000%	0.0000
4000462779	133795	11,499	4/11/2022	4/18/2022	7	0.003%	0.0002
4000462750	107191	2,086	4/11/2022	4/18/2022	7	0.001%	0.0000
4000462800	129435	289,823	4/12/2022	4/19/2022	7	0.076%	0.0054
4000462783	104195	43	4/12/2022	4/19/2022	7	0.000%	0.0000
4000462784	116384	78	4/12/2022	4/19/2022	7	0.000%	0.0000
4000462790	144567	16,596	4/12/2022	4/19/2022	7	0.004%	0.0003
4000462804	103620	245	4/13/2022	4/20/2022	7	0.000%	0.0000
4000462808	108180	2,000	4/13/2022	4/20/2022	7	0.001%	0.0000
4000462810	109075	2,500	4/13/2022	4/20/2022	7	0.001%	0.0000
4000462821	125742	1,746	4/13/2022	4/20/2022	7	0.000%	0.0000
4000462822	125814	31	4/13/2022	4/20/2022	7	0.000%	0.0000
4000462829	133086	500	4/13/2022	4/20/2022	7	0.000%	0.0000
4000462830	135488	138	4/13/2022	4/20/2022	7	0.000%	0.0000
4000462839	143741	3,750	4/13/2022	4/20/2022	7	0.001%	0.0001
4000462844	144955	4,363	4/13/2022	4/20/2022	7	0.001%	0.0001
4000462898	14060	900	4/14/2022	4/21/2022	7	0.000%	0.0000
4000462923	33956	822	4/14/2022	4/21/2022	7	0.000%	0.0000
4000462924	34064	831	4/14/2022	4/21/2022	7	0.000%	0.0000
4000462929	117331	15,094	4/14/2022	4/21/2022	7	0.004%	0.0003
4000462873	125742	55,707	4/14/2022	4/21/2022	7	0.015%	0.0010
4000462874	126476	891,681	4/14/2022	4/21/2022	7	0.235%	0.0165
4000462876	139713	77,190	4/14/2022	4/21/2022	7	0.020%	0.0014
4000462880	143477	8,162	4/14/2022	4/21/2022	7	0.002%	0.0002
4000462881	143577	14,067	4/14/2022	4/21/2022	7	0.004%	0.0003
4000462882	143659	4,876	4/14/2022	4/21/2022	7	0.001%	0.0001
4000462883	143867	7,323	4/14/2022	4/21/2022	7	0.002%	0.0001
4000462884	143920	110	4/14/2022	4/21/2022	7	0.000%	0.0000
4000462887	144097	208,750	4/14/2022	4/21/2022	7	0.055%	0.0039
4000462889	144567	15,781	4/14/2022	4/21/2022	7	0.004%	0.0003
4000462890	144567	24,056	4/14/2022	4/21/2022	7	0.006%	0.0004
4000462891	144567	14,838	4/14/2022	4/21/2022	7	0.004%	0.0003
4000462942	135057	1,678	4/18/2022	4/25/2022	7	0.000%	0.0000
4000462978	10384	900	4/19/2022	4/26/2022	7	0.000%	0.0000
4000462988	105195	13,486	4/19/2022	4/26/2022	7	0.004%	0.0002
4000462990	126775	582	4/19/2022	4/26/2022	7	0.000%	0.0000
4000462965	10384	6,000	4/19/2022	4/26/2022	7	0.002%	0.0001
4000462971	118807	1,135	4/19/2022	4/26/2022	7	0.000%	0.0000
4000462972	120845	50,000	4/19/2022	4/26/2022	7	0.013%	0.0009
4000462973	125742	1,711	4/19/2022	4/26/2022	7	0.000%	0.0000
4000462974	132094	4,666	4/19/2022	4/26/2022	7	0.001%	0.0001
4000463021	27013	14,738	4/20/2022	4/27/2022	7	0.004%	0.0003
4000463024	34064	246	4/20/2022	4/27/2022	7	0.000%	0.0000
4000462992	24765	5,739	4/20/2022	4/27/2022	7	0.002%	0.0001
4000462994	100342	15,000	4/20/2022	4/27/2022	7	0.004%	0.0003
4000462997	116902	1,050	4/20/2022	4/27/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463000	125742	11,351	4/20/2022	4/27/2022	7	0.003%	0.0002
4000463002	126568	100	4/20/2022	4/27/2022	7	0.000%	0.0000
4000463006	143463	23,370	4/20/2022	4/27/2022	7	0.006%	0.0004
4000463007	143577	10,533	4/20/2022	4/27/2022	7	0.003%	0.0002
4000463008	143584	98,658	4/20/2022	4/27/2022	7	0.026%	0.0018
4000463009	143659	8,518	4/20/2022	4/27/2022	7	0.002%	0.0002
4000463050	14949	8,809	4/21/2022	4/28/2022	7	0.002%	0.0002
4000463051	24259	2,248	4/21/2022	4/28/2022	7	0.001%	0.0000
4000463053	25708	2,056	4/21/2022	4/28/2022	7	0.001%	0.0000
4000463054	26297	667	4/21/2022	4/28/2022	7	0.000%	0.0000
4000463073	34658	2,000	4/21/2022	4/28/2022	7	0.001%	0.0000
4000463031	103008	790	4/21/2022	4/28/2022	7	0.000%	0.0000
4000463032	108289	64	4/21/2022	4/28/2022	7	0.000%	0.0000
4000463034	115651	25,000	4/21/2022	4/28/2022	7	0.007%	0.0005
4000463035	119251	7,275	4/21/2022	4/28/2022	7	0.002%	0.0001
4000463038	139733	258	4/21/2022	4/28/2022	7	0.000%	0.0000
4000463039	142700	7,010	4/21/2022	4/28/2022	7	0.002%	0.0001
4000463042	143340	695	4/21/2022	4/28/2022	7	0.000%	0.0000
4000463150	108092	64,080	4/25/2022	5/2/2022	7	0.017%	0.0012
4000463203	117331	39,550	4/26/2022	5/3/2022	7	0.010%	0.0007
4000463205	126775	9,173	4/26/2022	5/3/2022	7	0.002%	0.0002
4000463183	116384	185	4/26/2022	5/3/2022	7	0.000%	0.0000
4000463184	118807	722	4/26/2022	5/3/2022	7	0.000%	0.0000
4000463185	125742	12,267	4/26/2022	5/3/2022	7	0.003%	0.0002
4000463189	144097	813,485	4/26/2022	5/3/2022	7	0.215%	0.0150
4000463233	11474	475	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463234	18267	5,779	4/27/2022	5/4/2022	7	0.002%	0.0001
4000463239	26213	414	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463240	26363	1,068	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463241	26604	2,845	4/27/2022	5/4/2022	7	0.001%	0.0001
4000463242	26639	11,475	4/27/2022	5/4/2022	7	0.003%	0.0002
4000463244	26659	21,007	4/27/2022	5/4/2022	7	0.006%	0.0004
4000463250	30475	49,894	4/27/2022	5/4/2022	7	0.013%	0.0009
4000463253	34531	7,394	4/27/2022	5/4/2022	7	0.002%	0.0001
4000463256	117331	55,000	4/27/2022	5/4/2022	7	0.015%	0.0010
4000463257	117331	56,150	4/27/2022	5/4/2022	7	0.015%	0.0010
4000463210	15871	490	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463214	100203	2,975	4/27/2022	5/4/2022	7	0.001%	0.0001
4000463215	109457	10,000	4/27/2022	5/4/2022	7	0.003%	0.0002
4000463219	133414	131	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463222	138494	1,150	4/27/2022	5/4/2022	7	0.000%	0.0000
4000463292	11577	1,575	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463295	14949	31,565	4/28/2022	5/5/2022	7	0.008%	0.0006
4000463296	17342	6,750	4/28/2022	5/5/2022	7	0.002%	0.0001
4000463299	24259	3,148	4/28/2022	5/5/2022	7	0.001%	0.0001
4000463301	25659	17,238	4/28/2022	5/5/2022	7	0.005%	0.0003
4000463305	26213	1,104	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463307	26338	1,012	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463309	26604	7,340	4/28/2022	5/5/2022	7	0.002%	0.0001
4000463311	26642	2,738	4/28/2022	5/5/2022	7	0.001%	0.0001
4000463313	26659	1,184	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463314	26679	8,813	4/28/2022	5/5/2022	7	0.002%	0.0002
4000463318	29469	2,185	4/28/2022	5/5/2022	7	0.001%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463321	117331	31,663	4/28/2022	5/5/2022	7	0.008%	0.0006
4000463264	26958	2,019	4/28/2022	5/5/2022	7	0.001%	0.0000
4000463266	100103	198	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463268	103913	311	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463271	111669	18	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463272	112215	191	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463274	125349	1,500	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463277	138494	6,545	4/28/2022	5/5/2022	7	0.002%	0.0001
4000463281	143270	373	4/28/2022	5/5/2022	7	0.000%	0.0000
4000463288	145092	2,095	4/28/2022	5/5/2022	7	0.001%	0.0000
4000463416	125742	9,805	5/2/2022	5/9/2022	7	0.003%	0.0002
4000463420	138494	88	5/2/2022	5/9/2022	7	0.000%	0.0000
4000463515	126775	1,240	5/3/2022	5/10/2022	7	0.000%	0.0000
4000463454	8556	483	5/3/2022	5/10/2022	7	0.000%	0.0000
4000463459	116332	287,098	5/3/2022	5/10/2022	7	0.076%	0.0053
4000463461	118807	359	5/3/2022	5/10/2022	7	0.000%	0.0000
4000463464	129031	504	5/3/2022	5/10/2022	7	0.000%	0.0000
4000463468	134906	3,900	5/3/2022	5/10/2022	7	0.001%	0.0001
4000463471	139982	9,422	5/3/2022	5/10/2022	7	0.002%	0.0002
4000463475	141822	8,319	5/3/2022	5/10/2022	7	0.002%	0.0002
4000463479	142162	11,000	5/3/2022	5/10/2022	7	0.003%	0.0002
4000463494	144510	2,000	5/3/2022	5/10/2022	7	0.001%	0.0000
4000463498	144972	8,655	5/3/2022	5/10/2022	7	0.002%	0.0002
4000463500	144996	2,500	5/3/2022	5/10/2022	7	0.001%	0.0000
4000463451	26996	7,500	5/3/2022	5/10/2022	7	0.002%	0.0001
4000463536	25173	4,400	5/4/2022	5/11/2022	7	0.001%	0.0001
4000463538	27013	922	5/4/2022	5/11/2022	7	0.000%	0.0000
4000463539	30475	14,179	5/4/2022	5/11/2022	7	0.004%	0.0003
4000463542	117331	116,100	5/4/2022	5/11/2022	7	0.031%	0.0021
4000463518	106674	26,456	5/4/2022	5/11/2022	7	0.007%	0.0005
4000463526	143588	15,003	5/4/2022	5/11/2022	7	0.004%	0.0003
4000463527	143741	3,950	5/4/2022	5/11/2022	7	0.001%	0.0001
4000463573	25131	760	5/5/2022	5/12/2022	7	0.000%	0.0000
4000463574	34341	6,600	5/5/2022	5/12/2022	7	0.002%	0.0001
4000463547	15871	2,220	5/5/2022	5/12/2022	7	0.001%	0.0000
4000463548	26604	5,165	5/5/2022	5/12/2022	7	0.001%	0.0001
4000463551	103008	12	5/5/2022	5/12/2022	7	0.000%	0.0000
4000463554	104154	88	5/5/2022	5/12/2022	7	0.000%	0.0000
4000463557	108289	129	5/5/2022	5/12/2022	7	0.000%	0.0000
4000463562	142700	6,060	5/5/2022	5/12/2022	7	0.002%	0.0001
4000463570	144955	14,000	5/5/2022	5/12/2022	7	0.004%	0.0003
4000463545	127614	5,615	5/5/2022	5/12/2022	7	0.001%	0.0001
4000463546	127614	7,160	5/5/2022	5/12/2022	7	0.002%	0.0001
4000463667	14949	12,297	5/10/2022	5/17/2022	7	0.003%	0.0002
4000463668	17342	7,088	5/10/2022	5/17/2022	7	0.002%	0.0001
4000463672	26356	2,096	5/10/2022	5/17/2022	7	0.001%	0.0000
4000463653	116384	457	5/10/2022	5/17/2022	7	0.000%	0.0000
4000463654	118807	2,305	5/10/2022	5/17/2022	7	0.001%	0.0000
4000463661	143659	3,160	5/10/2022	5/17/2022	7	0.001%	0.0001
4000463663	144530	10,245	5/10/2022	5/17/2022	7	0.003%	0.0002
4000463711	11305	667	5/11/2022	5/18/2022	7	0.000%	0.0000
4000463716	25131	665	5/11/2022	5/18/2022	7	0.000%	0.0000
4000463720	26639	27,068	5/11/2022	5/18/2022	7	0.007%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463688	26168	7,887	5/11/2022	5/18/2022	7	0.002%	0.0001
4000463691	103867	7	5/11/2022	5/18/2022	7	0.000%	0.0000
4000463695	123915	2,860	5/11/2022	5/18/2022	7	0.001%	0.0001
4000463706	144955	779	5/11/2022	5/18/2022	7	0.000%	0.0000
4000463707	144982	811	5/11/2022	5/18/2022	7	0.000%	0.0000
4000463754	133795	11,499	5/12/2022	5/19/2022	7	0.003%	0.0002
4000463740	26604	6,445	5/12/2022	5/19/2022	7	0.002%	0.0001
4000463911	116384	5	5/17/2022	5/24/2022	7	0.000%	0.0000
4000463913	132202	5,131	5/17/2022	5/24/2022	7	0.001%	0.0001
4000463955	26016	1,461	5/18/2022	5/25/2022	7	0.000%	0.0000
4000463956	26213	1,012	5/18/2022	5/25/2022	7	0.000%	0.0000
4000463960	27013	1,276	5/18/2022	5/25/2022	7	0.000%	0.0000
4000463961	28084	25,745	5/18/2022	5/25/2022	7	0.007%	0.0005
4000463925	4765	17,000	5/18/2022	5/25/2022	7	0.004%	0.0003
4000463928	34888	116	5/18/2022	5/25/2022	7	0.000%	0.0000
4000463938	121825	23,998	5/18/2022	5/25/2022	7	0.006%	0.0004
4000463939	125742	4,064	5/18/2022	5/25/2022	7	0.001%	0.0001
4000463940	132507	5,900	5/18/2022	5/25/2022	7	0.002%	0.0001
4000464000	17342	2,430	5/19/2022	5/26/2022	7	0.001%	0.0000
4000464008	30475	38,814	5/19/2022	5/26/2022	7	0.010%	0.0007
4000464009	30475	32,673	5/19/2022	5/26/2022	7	0.009%	0.0006
4000463980	27094	2,649	5/19/2022	5/26/2022	7	0.001%	0.0000
4000463986	121825	5,250	5/19/2022	5/26/2022	7	0.001%	0.0001
4000463987	125742	6,340	5/19/2022	5/26/2022	7	0.002%	0.0001
4000463988	135488	34,500	5/19/2022	5/26/2022	7	0.009%	0.0006
4000463991	143340	129,960	5/19/2022	5/26/2022	7	0.034%	0.0024
4000463994	144178	12,100	5/19/2022	5/26/2022	7	0.003%	0.0002
4000464023	116332	8,809	5/20/2022	5/27/2022	7	0.002%	0.0002
4000464100	112215	500	5/24/2022	5/31/2022	7	0.000%	0.0000
4000464175	30475	54,131	5/25/2022	6/1/2022	7	0.014%	0.0010
4000464179	105195	1,209	5/25/2022	6/1/2022	7	0.000%	0.0000
4000464141	107191	114	5/25/2022	6/1/2022	7	0.000%	0.0000
4000464143	116332	12,256	5/25/2022	6/1/2022	7	0.003%	0.0002
4000464146	134862	668,392	5/25/2022	6/1/2022	7	0.176%	0.0123
4000464149	141101	35,432	5/25/2022	6/1/2022	7	0.009%	0.0007
4000464154	144270	9,908	5/25/2022	6/1/2022	7	0.003%	0.0002
4000464210	11305	299	5/26/2022	6/2/2022	7	0.000%	0.0000
4000464212	18275	10,140	5/26/2022	6/2/2022	7	0.003%	0.0002
4000464215	25599	2,927	5/26/2022	6/2/2022	7	0.001%	0.0001
4000464220	27013	9,447	5/26/2022	6/2/2022	7	0.002%	0.0002
4000464221	27704	1,950	5/26/2022	6/2/2022	7	0.001%	0.0000
4000464223	28474	2,314	5/26/2022	6/2/2022	7	0.001%	0.0000
4000464226	29469	2,070	5/26/2022	6/2/2022	7	0.001%	0.0000
4000464234	124943	2,043	5/26/2022	6/2/2022	7	0.001%	0.0000
4000464183	27094	2,649	5/26/2022	6/2/2022	7	0.001%	0.0000
4000464187	118807	429	5/26/2022	6/2/2022	7	0.000%	0.0000
4000464188	125742	22,470	5/26/2022	6/2/2022	7	0.006%	0.0004
4000464192	139713	253,839	5/26/2022	6/2/2022	7	0.067%	0.0047
4000464199	143659	1,417	5/26/2022	6/2/2022	7	0.000%	0.0000
4000464203	144791	2,800	5/26/2022	6/2/2022	7	0.001%	0.0001
4000464205	145034	196,779	5/26/2022	6/2/2022	7	0.052%	0.0036
4000464346	24385	12,602	5/31/2022	6/7/2022	7	0.003%	0.0002
4000464367	34064	251,566	5/31/2022	6/7/2022	7	0.066%	0.0046

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464313	32842	1,834	5/31/2022	6/7/2022	7	0.000%	0.0000
4000464316	105195	14,319	5/31/2022	6/7/2022	7	0.004%	0.0003
4000464322	116384	245	5/31/2022	6/7/2022	7	0.000%	0.0000
4000464323	118807	238	5/31/2022	6/7/2022	7	0.000%	0.0000
4000464325	119733	2,500	5/31/2022	6/7/2022	7	0.001%	0.0000
4000464329	132094	100	5/31/2022	6/7/2022	7	0.000%	0.0000
4000464334	143011	10,265	5/31/2022	6/7/2022	7	0.003%	0.0002
4000464335	143463	27,300	5/31/2022	6/7/2022	7	0.007%	0.0005
4000464336	143741	550	5/31/2022	6/7/2022	7	0.000%	0.0000
4000464337	144097	4,312,600	5/31/2022	6/7/2022	7	1.137%	0.0796
4000464391	1908	11,040	6/1/2022	6/8/2022	7	0.003%	0.0002
4000464398	24383	628	6/1/2022	6/8/2022	7	0.000%	0.0000
4000464403	26356	1,516	6/1/2022	6/8/2022	7	0.000%	0.0000
4000464404	26639	540	6/1/2022	6/8/2022	7	0.000%	0.0000
4000464407	26659	21,256	6/1/2022	6/8/2022	7	0.006%	0.0004
4000464410	30475	71	6/1/2022	6/8/2022	7	0.000%	0.0000
4000464374	15871	1,122	6/1/2022	6/8/2022	7	0.000%	0.0000
4000464380	134862	46,795	6/1/2022	6/8/2022	7	0.012%	0.0009
4000464387	144912	143,750	6/1/2022	6/8/2022	7	0.038%	0.0027
4000464440	141822	8,480	6/2/2022	6/9/2022	7	0.002%	0.0002
4000464508	142613	24,514	6/3/2022	6/10/2022	7	0.006%	0.0005
4000464547	112215	1,290	6/6/2022	6/13/2022	7	0.000%	0.0000
4000464579	32842	88	6/7/2022	6/14/2022	7	0.000%	0.0000
4000464581	116384	60	6/7/2022	6/14/2022	7	0.000%	0.0000
4000464584	143659	1,593	6/7/2022	6/14/2022	7	0.000%	0.0000
4000464585	144084	920	6/7/2022	6/14/2022	7	0.000%	0.0000
4000464587	144567	12,283	6/7/2022	6/14/2022	7	0.003%	0.0002
4000464637	27013	5,621	6/8/2022	6/15/2022	7	0.001%	0.0001
4000464612	15871	8,518	6/8/2022	6/15/2022	7	0.002%	0.0002
4000464614	36297	17,960	6/8/2022	6/15/2022	7	0.005%	0.0003
4000464617	104496	38	6/8/2022	6/15/2022	7	0.000%	0.0000
4000464619	116332	208,451	6/8/2022	6/15/2022	7	0.055%	0.0038
4000464624	134862	370,301	6/8/2022	6/15/2022	7	0.098%	0.0068
4000464631	144479	275,622	6/8/2022	6/15/2022	7	0.073%	0.0051
4000464671	33956	500	6/9/2022	6/16/2022	7	0.000%	0.0000
4000464672	34064	251	6/9/2022	6/16/2022	7	0.000%	0.0000
4000464649	112215	1,262	6/9/2022	6/16/2022	7	0.000%	0.0000
4000464653	135058	43,900	6/9/2022	6/16/2022	7	0.012%	0.0008
4000464657	143741	1,850	6/9/2022	6/16/2022	7	0.000%	0.0000
4000464658	144270	48,780	6/9/2022	6/16/2022	7	0.013%	0.0009
4000464662	144955	7,910	6/9/2022	6/16/2022	7	0.002%	0.0001
4000464710	143694	2,724	6/10/2022	6/17/2022	7	0.001%	0.0001
4000464799	142635	12,449	6/14/2022	6/21/2022	7	0.003%	0.0002
4000464850	26604	15,130	6/15/2022	6/22/2022	7	0.004%	0.0003
4000464860	34064	125	6/15/2022	6/22/2022	7	0.000%	0.0000
4000464861	34088	1,303	6/15/2022	6/22/2022	7	0.000%	0.0000
4000464862	34341	7,700	6/15/2022	6/22/2022	7	0.002%	0.0001
4000464818	3970	2,455	6/15/2022	6/22/2022	7	0.001%	0.0000
4000464819	15871	490	6/15/2022	6/22/2022	7	0.000%	0.0000
4000464829	118807	1,272	6/15/2022	6/22/2022	7	0.000%	0.0000
4000464835	141423	3,200	6/15/2022	6/22/2022	7	0.001%	0.0001
4000464838	143154	808	6/15/2022	6/22/2022	7	0.000%	0.0000
4000464839	144084	11,790	6/15/2022	6/22/2022	7	0.003%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464887	9001	140,962	6/16/2022	6/23/2022	7	0.037%	0.0026
4000464888	9121	4,600	6/16/2022	6/23/2022	7	0.001%	0.0001
4000464890	24259	5,846	6/16/2022	6/23/2022	7	0.002%	0.0001
4000464893	28084	15,153	6/16/2022	6/23/2022	7	0.004%	0.0003
4000464894	30475	4,265	6/16/2022	6/23/2022	7	0.001%	0.0001
4000464895	34348	2,520	6/16/2022	6/23/2022	7	0.001%	0.0000
4000464867	26471	33,645	6/16/2022	6/23/2022	7	0.009%	0.0006
4000464870	112215	730	6/16/2022	6/23/2022	7	0.000%	0.0000
4000464871	116384	5	6/16/2022	6/23/2022	7	0.000%	0.0000
4000464880	143189	1,562	6/16/2022	6/23/2022	7	0.000%	0.0000
4000464881	143477	2,527	6/16/2022	6/23/2022	7	0.001%	0.0000
4000464883	144270	93,096	6/16/2022	6/23/2022	7	0.025%	0.0017
4000465013	24281	6,104	6/21/2022	6/28/2022	7	0.002%	0.0001
4000465000	12081	1,436	6/21/2022	6/28/2022	7	0.000%	0.0000
4000465006	116384	67	6/21/2022	6/28/2022	7	0.000%	0.0000
4000465047	30257	107,401	6/22/2022	6/29/2022	7	0.028%	0.0020
4000465050	32875	4,500	6/22/2022	6/29/2022	7	0.001%	0.0001
4000465022	34888	575	6/22/2022	6/29/2022	7	0.000%	0.0000
4000465025	125742	7,343	6/22/2022	6/29/2022	7	0.002%	0.0001
4000465026	138494	10,200	6/22/2022	6/29/2022	7	0.003%	0.0002
4000465027	141101	20,635	6/22/2022	6/29/2022	7	0.005%	0.0004
4000465033	144760	769	6/22/2022	6/29/2022	7	0.000%	0.0000
4000465088	11372	1,957	6/23/2022	6/30/2022	7	0.001%	0.0000
4000465091	25599	7,168	6/23/2022	6/30/2022	7	0.002%	0.0001
4000465092	25905	3,300	6/23/2022	6/30/2022	7	0.001%	0.0001
4000465096	27013	3,060	6/23/2022	6/30/2022	7	0.001%	0.0001
4000465060	10384	4,600	6/23/2022	6/30/2022	7	0.001%	0.0001
4000465067	116384	812	6/23/2022	6/30/2022	7	0.000%	0.0000
4000465070	121825	13,499	6/23/2022	6/30/2022	7	0.004%	0.0002
4000465072	131305	23,300	6/23/2022	6/30/2022	7	0.006%	0.0004
4000465073	132743	1,734	6/23/2022	6/30/2022	7	0.000%	0.0000
4000465078	143340	104,423	6/23/2022	6/30/2022	7	0.028%	0.0019
4000465082	144097	1,260,600	6/23/2022	6/30/2022	7	0.332%	0.0233
4000465120	112215	12,498	6/24/2022	7/1/2022	7	0.003%	0.0002
4000465121	112215	20,353	6/24/2022	7/1/2022	7	0.005%	0.0004
4000465123	116332	82,823	6/24/2022	7/1/2022	7	0.022%	0.0015
4000465136	143694	480	6/24/2022	7/1/2022	7	0.000%	0.0000
4000465288	10384	800	6/29/2022	7/6/2022	7	0.000%	0.0000
4000465295	106699	5,994	6/29/2022	7/6/2022	7	0.002%	0.0001
4000465273	27476	841	6/29/2022	7/6/2022	7	0.000%	0.0000
4000465275	116332	23,518	6/29/2022	7/6/2022	7	0.006%	0.0004
4000465276	116384	130	6/29/2022	7/6/2022	7	0.000%	0.0000
4000465277	118807	623	6/29/2022	7/6/2022	7	0.000%	0.0000
4000465285	144912	201,250	6/29/2022	7/6/2022	7	0.053%	0.0037
4000465360	17342	11,543	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465361	18267	4,088	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465362	23681	4,233	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465365	26297	632	6/30/2022	7/7/2022	7	0.000%	0.0000
4000465368	26659	7,044	6/30/2022	7/7/2022	7	0.002%	0.0001
4000465373	34341	3,300	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465375	34658	2,500	6/30/2022	7/7/2022	7	0.001%	0.0000
4000465299	15871	6,498	6/30/2022	7/7/2022	7	0.002%	0.0001
4000465308	116332	675,745	6/30/2022	7/7/2022	7	0.178%	0.0125

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465313	133414	4,947	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465314	134906	3,900	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465316	136045	42,000	6/30/2022	7/7/2022	7	0.011%	0.0008
4000465318	139713	38,595	6/30/2022	7/7/2022	7	0.010%	0.0007
4000465321	141370	13,250	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465322	141822	8,480	6/30/2022	7/7/2022	7	0.002%	0.0002
4000465323	141826	9,333	6/30/2022	7/7/2022	7	0.002%	0.0002
4000465327	142162	11,000	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465328	142607	2,500	6/30/2022	7/7/2022	7	0.001%	0.0000
4000465333	143270	4,500	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465337	143463	11,954	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465339	143637	3,750	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465341	143929	22,666	6/30/2022	7/7/2022	7	0.006%	0.0004
4000465342	144015	10,000	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465345	144358	25,631	6/30/2022	7/7/2022	7	0.007%	0.0005
4000465346	144410	2,850	6/30/2022	7/7/2022	7	0.001%	0.0001
4000465349	144773	625	6/30/2022	7/7/2022	7	0.000%	0.0000
4000465351	144927	6,000	6/30/2022	7/7/2022	7	0.002%	0.0001
4000465353	144972	8,655	6/30/2022	7/7/2022	7	0.002%	0.0002
4000465355	145034	11,345	6/30/2022	7/7/2022	7	0.003%	0.0002
4000465470	103392	19	7/5/2022	7/12/2022	7	0.000%	0.0000
4000465473	116384	192	7/5/2022	7/12/2022	7	0.000%	0.0000
4000465475	130315	39	7/5/2022	7/12/2022	7	0.000%	0.0000
4000465482	145181	1,200	7/5/2022	7/12/2022	7	0.000%	0.0000
4000465522	26639	1,620	7/6/2022	7/13/2022	7	0.000%	0.0000
4000465494	4502	2,130	7/6/2022	7/13/2022	7	0.001%	0.0000
4000465513	134862	2,595,720	7/6/2022	7/13/2022	7	0.685%	0.0479
4000465549	10384	1,600	7/7/2022	7/14/2022	7	0.000%	0.0000
4000465551	18267	2,652	7/7/2022	7/14/2022	7	0.001%	0.0000
4000465556	26604	11,310	7/7/2022	7/14/2022	7	0.003%	0.0002
4000465533	27094	1,442	7/7/2022	7/14/2022	7	0.000%	0.0000
4000465536	103114	63	7/7/2022	7/14/2022	7	0.000%	0.0000
4000465537	112215	14,840	7/7/2022	7/14/2022	7	0.004%	0.0003
4000465543	139713	38,595	7/7/2022	7/14/2022	7	0.010%	0.0007
4000465545	143485	139,545	7/7/2022	7/14/2022	7	0.037%	0.0026
4000465660	133795	11,499	7/11/2022	7/18/2022	7	0.003%	0.0002
4000465639	141114	2,893	7/11/2022	7/18/2022	7	0.001%	0.0001
4000465644	144270	4,873	7/11/2022	7/18/2022	7	0.001%	0.0001
4000465718	135488	40,800	7/12/2022	7/19/2022	7	0.011%	0.0008
4000465723	143659	15,432	7/12/2022	7/19/2022	7	0.004%	0.0003
4000465763	27068	13,737	7/13/2022	7/20/2022	7	0.004%	0.0003
4000465770	34348	2,760	7/13/2022	7/20/2022	7	0.001%	0.0001
4000465773	130375	629	7/13/2022	7/20/2022	7	0.000%	0.0000
4000465735	13672	1,500	7/13/2022	7/20/2022	7	0.000%	0.0000
4000465737	15871	6,059	7/13/2022	7/20/2022	7	0.002%	0.0001
4000465744	112215	1,503	7/13/2022	7/20/2022	7	0.000%	0.0000
4000465747	121533	500	7/13/2022	7/20/2022	7	0.000%	0.0000
4000465752	143250	4,200	7/13/2022	7/20/2022	7	0.001%	0.0001
4000465757	144878	1,660	7/13/2022	7/20/2022	7	0.000%	0.0000
4000465798	26604	33,980	7/14/2022	7/21/2022	7	0.009%	0.0006
4000465799	26639	2,970	7/14/2022	7/21/2022	7	0.001%	0.0001
4000465800	26655	862	7/14/2022	7/21/2022	7	0.000%	0.0000
4000465802	26679	1,000	7/14/2022	7/21/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465805	32875	800	7/14/2022	7/21/2022	7	0.000%	0.0000
4000465810	106699	2,081	7/14/2022	7/21/2022	7	0.001%	0.0000
4000465811	117331	1,900	7/14/2022	7/21/2022	7	0.001%	0.0000
4000465777	104195	45	7/14/2022	7/21/2022	7	0.000%	0.0000
4000465784	138494	10,200	7/14/2022	7/21/2022	7	0.003%	0.0002
4000465879	144281	4,000	7/18/2022	7/25/2022	7	0.001%	0.0001
4000465912	26674	1,120	7/19/2022	7/26/2022	7	0.000%	0.0000
4000465901	143588	1,028	7/19/2022	7/26/2022	7	0.000%	0.0000
4000465971	26604	3,855	7/20/2022	7/27/2022	7	0.001%	0.0001
4000465974	28084	1,140	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465978	32875	600	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465981	117331	59,643	7/20/2022	7/27/2022	7	0.016%	0.0011
4000465945	112215	5,800	7/20/2022	7/27/2022	7	0.002%	0.0001
4000465947	116384	378	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465949	118807	1,301	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465954	142700	6,060	7/20/2022	7/27/2022	7	0.002%	0.0001
4000465955	142942	448	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465958	143577	5,734	7/20/2022	7/27/2022	7	0.002%	0.0001
4000465964	144949	55	7/20/2022	7/27/2022	7	0.000%	0.0000
4000465989	17667	138,100	7/21/2022	7/28/2022	7	0.036%	0.0025
4000465991	112215	14,818	7/21/2022	7/28/2022	7	0.004%	0.0003
4000465994	139713	154,380	7/21/2022	7/28/2022	7	0.041%	0.0029
4000465998	143659	27,004	7/21/2022	7/28/2022	7	0.007%	0.0005
4000466000	144468	2,400	7/21/2022	7/28/2022	7	0.001%	0.0000
4000466164	117331	10,679	7/26/2022	8/2/2022	7	0.003%	0.0002
4000466109	32842	1,630	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466110	103392	15	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466111	112215	500	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466112	116384	245	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466115	125742	150	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466123	141822	8,480	7/26/2022	8/2/2022	7	0.002%	0.0002
4000466130	143011	2,072	7/26/2022	8/2/2022	7	0.001%	0.0000
4000466135	143622	667	7/26/2022	8/2/2022	7	0.000%	0.0000
4000466136	143659	37,454	7/26/2022	8/2/2022	7	0.010%	0.0007
4000466143	144510	2,000	7/26/2022	8/2/2022	7	0.001%	0.0000
4000466146	144567	6,700	7/26/2022	8/2/2022	7	0.002%	0.0001
4000466187	18275	21,325	7/27/2022	8/3/2022	7	0.006%	0.0004
4000466168	103392	259	7/27/2022	8/3/2022	7	0.000%	0.0000
4000466179	143577	6,405	7/27/2022	8/3/2022	7	0.002%	0.0001
4000466180	144097	8,133,906	7/27/2022	8/3/2022	7	2.145%	0.1502
4000466183	144982	37,699	7/27/2022	8/3/2022	7	0.010%	0.0007
4000466235	26639	27,203	7/28/2022	8/4/2022	7	0.007%	0.0005
4000466249	34658	3,700	7/28/2022	8/4/2022	7	0.001%	0.0001
4000466211	26958	1,015	7/28/2022	8/4/2022	7	0.000%	0.0000
4000466213	111770	292	7/28/2022	8/4/2022	7	0.000%	0.0000
4000466214	118807	674	7/28/2022	8/4/2022	7	0.000%	0.0000
4000466219	135194	101,696	7/28/2022	8/4/2022	7	0.027%	0.0019
4000466222	142700	24,242	7/28/2022	8/4/2022	7	0.006%	0.0004
4000466224	143340	13,705	7/28/2022	8/4/2022	7	0.004%	0.0003
4000466200	127614	7,034	7/28/2022	8/4/2022	7	0.002%	0.0001
4000466276	135194	38,045	7/29/2022	8/5/2022	7	0.010%	0.0007
4000466358	144097	158,681	8/1/2022	8/8/2022	7	0.042%	0.0029
4000466359	144915	76,215	8/1/2022	8/8/2022	7	0.020%	0.0014

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466396	32934	6,366	8/1/2022	8/8/2022	7	0.002%	0.0001
4000466397	32940	112,481	8/1/2022	8/8/2022	7	0.030%	0.0021
4000466400	32988	1,834	8/1/2022	8/8/2022	7	0.000%	0.0000
4000466402	32998	24,487	8/1/2022	8/8/2022	7	0.006%	0.0005
4000466404	33012	435	8/1/2022	8/8/2022	7	0.000%	0.0000
4000466406	33018	91,877	8/1/2022	8/8/2022	7	0.024%	0.0017
4000466411	33048	7,328	8/1/2022	8/8/2022	7	0.002%	0.0001
4000466416	33121	4,951	8/1/2022	8/8/2022	7	0.001%	0.0001
4000466420	33144	54,463	8/1/2022	8/8/2022	7	0.014%	0.0010
4000466423	33153	25,563	8/1/2022	8/8/2022	7	0.007%	0.0005
4000466427	116384	8	8/2/2022	8/9/2022	7	0.000%	0.0000
4000466428	118807	2,602	8/2/2022	8/9/2022	7	0.001%	0.0000
4000466464	10384	1,100	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466446	104154	533	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466448	111669	18	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466451	118807	37	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466456	130315	40	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466457	138494	51	8/3/2022	8/10/2022	7	0.000%	0.0000
4000466535	112215	2,266	8/5/2022	8/12/2022	7	0.001%	0.0000
4000466582	112215	812	8/8/2022	8/15/2022	7	0.000%	0.0000
4000466585	142613	17,380	8/8/2022	8/15/2022	7	0.005%	0.0003
4000466637	11305	1,182	8/9/2022	8/16/2022	7	0.000%	0.0000
4000466617	24825	3,173	8/9/2022	8/16/2022	7	0.001%	0.0001
4000466622	116384	167	8/9/2022	8/16/2022	7	0.000%	0.0000
4000466623	118807	452	8/9/2022	8/16/2022	7	0.000%	0.0000
4000466624	125303	20,000	8/9/2022	8/16/2022	7	0.005%	0.0004
4000466634	144567	2,910	8/9/2022	8/16/2022	7	0.001%	0.0001
4000466689	34064	275	8/10/2022	8/17/2022	7	0.000%	0.0000
4000466693	117331	10,089	8/10/2022	8/17/2022	7	0.003%	0.0002
4000466642	4502	6,850	8/10/2022	8/17/2022	7	0.002%	0.0001
4000466651	112215	1,622	8/10/2022	8/17/2022	7	0.000%	0.0000
4000466665	138551	1,500	8/10/2022	8/17/2022	7	0.000%	0.0000
4000466669	142942	2,427	8/10/2022	8/17/2022	7	0.001%	0.0000
4000466706	33085	12,682	8/10/2022	8/17/2022	7	0.003%	0.0002
4000466709	33090	24,395	8/10/2022	8/17/2022	7	0.006%	0.0005
4000466711	33099	59,617	8/10/2022	8/17/2022	7	0.016%	0.0011
4000466779	107191	57	8/12/2022	8/19/2022	7	0.000%	0.0000
4000466830	125742	3,140	8/15/2022	8/22/2022	7	0.001%	0.0001
4000466892	28474	1,122	8/16/2022	8/23/2022	7	0.000%	0.0000
4000466896	117331	11,000	8/16/2022	8/23/2022	7	0.003%	0.0002
4000466860	27094	4,415	8/16/2022	8/23/2022	7	0.001%	0.0001
4000466866	116051	2,185	8/16/2022	8/23/2022	7	0.001%	0.0000
4000466882	144567	1,893	8/16/2022	8/23/2022	7	0.000%	0.0000
4000466920	14949	1,322	8/17/2022	8/24/2022	7	0.000%	0.0000
4000466923	24385	6,263	8/17/2022	8/24/2022	7	0.002%	0.0001
4000466926	26207	2,525	8/17/2022	8/24/2022	7	0.001%	0.0000
4000466936	33956	1,191	8/17/2022	8/24/2022	7	0.000%	0.0000
4000466938	105195	16,500	8/17/2022	8/24/2022	7	0.004%	0.0003
4000466901	27094	6,067	8/17/2022	8/24/2022	7	0.002%	0.0001
4000466902	34888	79	8/17/2022	8/24/2022	7	0.000%	0.0000
4000466908	118807	1,289	8/17/2022	8/24/2022	7	0.000%	0.0000
4000466964	24281	7,072	8/18/2022	8/25/2022	7	0.002%	0.0001
4000466965	26659	5,735	8/18/2022	8/25/2022	7	0.002%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466968	30475	41,911	8/18/2022	8/25/2022	7	0.011%	0.0008
4000466969	30475	51,968	8/18/2022	8/25/2022	7	0.014%	0.0010
4000466971	34064	10	8/18/2022	8/25/2022	7	0.000%	0.0000
4000466944	27094	25,364	8/18/2022	8/25/2022	7	0.007%	0.0005
4000466949	118807	654	8/18/2022	8/25/2022	7	0.000%	0.0000
4000466957	140752	55,459	8/18/2022	8/25/2022	7	0.015%	0.0010
4000466958	140752	42,109	8/18/2022	8/25/2022	7	0.011%	0.0008
4000466961	143659	50,361	8/18/2022	8/25/2022	7	0.013%	0.0009
4000466963	144567	1,669	8/18/2022	8/25/2022	7	0.000%	0.0000
4000467032	32929	29,866	8/19/2022	8/26/2022	7	0.008%	0.0006
4000467034	32944	51,499	8/19/2022	8/26/2022	7	0.014%	0.0010
4000467037	32953	40,982	8/19/2022	8/26/2022	7	0.011%	0.0008
4000467038	32962	11,539	8/19/2022	8/26/2022	7	0.003%	0.0002
4000467040	32987	8,995	8/19/2022	8/26/2022	7	0.002%	0.0002
4000467041	32996	57,946	8/19/2022	8/26/2022	7	0.015%	0.0011
4000467042	32997	42,432	8/19/2022	8/26/2022	7	0.011%	0.0008
4000467043	33002	6,560	8/19/2022	8/26/2022	7	0.002%	0.0001
4000467044	33003	13,715	8/19/2022	8/26/2022	7	0.004%	0.0003
4000467046	33011	18,553	8/19/2022	8/26/2022	7	0.005%	0.0003
4000467048	33024	146,685	8/19/2022	8/26/2022	7	0.039%	0.0027
4000467049	33028	174,934	8/19/2022	8/26/2022	7	0.046%	0.0032
4000467051	33038	4,904	8/19/2022	8/26/2022	7	0.001%	0.0001
4000467053	33060	6,422	8/19/2022	8/26/2022	7	0.002%	0.0001
4000467055	33083	116,506	8/19/2022	8/26/2022	7	0.031%	0.0022
4000467056	33112	368	8/19/2022	8/26/2022	7	0.000%	0.0000
4000467058	33150	68,188	8/19/2022	8/26/2022	7	0.018%	0.0013
4000467067	111120	279,455	8/22/2022	8/29/2022	7	0.074%	0.0052
4000467079	143072	314	8/22/2022	8/29/2022	7	0.000%	0.0000
4000467108	124943	665	8/23/2022	8/30/2022	7	0.000%	0.0000
4000467091	103392	84	8/23/2022	8/30/2022	7	0.000%	0.0000
4000467092	110291	11,241	8/23/2022	8/30/2022	7	0.003%	0.0002
4000467093	118807	115	8/23/2022	8/30/2022	7	0.000%	0.0000
4000467097	143584	12,180	8/23/2022	8/30/2022	7	0.003%	0.0002
4000467136	18267	5,402	8/24/2022	8/31/2022	7	0.001%	0.0001
4000467143	30475	55,038	8/24/2022	8/31/2022	7	0.015%	0.0010
4000467144	30475	30,185	8/24/2022	8/31/2022	7	0.008%	0.0006
4000467145	30475	36,153	8/24/2022	8/31/2022	7	0.010%	0.0007
4000467146	30475	39,025	8/24/2022	8/31/2022	7	0.010%	0.0007
4000467148	34064	1,246	8/24/2022	8/31/2022	7	0.000%	0.0000
4000467149	105195	24,076	8/24/2022	8/31/2022	7	0.006%	0.0004
4000467150	117331	7,284	8/24/2022	8/31/2022	7	0.002%	0.0001
4000467116	105195	2,039	8/24/2022	8/31/2022	7	0.001%	0.0000
4000467118	110291	16,076	8/24/2022	8/31/2022	7	0.004%	0.0003
4000467119	112215	12,498	8/24/2022	8/31/2022	7	0.003%	0.0002
4000467123	121825	83,992	8/24/2022	8/31/2022	7	0.022%	0.0016
4000467126	142942	1,871	8/24/2022	8/31/2022	7	0.000%	0.0000
4000467127	142942	4,263	8/24/2022	8/31/2022	7	0.001%	0.0001
4000467129	143111	1,000	8/24/2022	8/31/2022	7	0.000%	0.0000
4000467132	144982	1,411	8/24/2022	8/31/2022	7	0.000%	0.0000
4000467178	10384	1,850	8/25/2022	9/1/2022	7	0.000%	0.0000
4000467179	18267	5,665	8/25/2022	9/1/2022	7	0.001%	0.0001
4000467183	25599	4,036	8/25/2022	9/1/2022	7	0.001%	0.0001
4000467196	117331	58,286	8/25/2022	9/1/2022	7	0.015%	0.0011

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467197	117331	61,157	8/25/2022	9/1/2022	7	0.016%	0.0011
4000467154	26471	2,186	8/25/2022	9/1/2022	7	0.001%	0.0000
4000467158	105195	2,763	8/25/2022	9/1/2022	7	0.001%	0.0001
4000467161	111669	199	8/25/2022	9/1/2022	7	0.000%	0.0000
4000467165	118807	2,913	8/25/2022	9/1/2022	7	0.001%	0.0001
4000467167	132202	26,300	8/25/2022	9/1/2022	7	0.007%	0.0005
4000467168	132321	104	8/25/2022	9/1/2022	7	0.000%	0.0000
4000467173	143920	426	8/25/2022	9/1/2022	7	0.000%	0.0000
4000467175	145293	22,037	8/25/2022	9/1/2022	7	0.006%	0.0004
4000467210	112215	8,774	8/26/2022	9/2/2022	7	0.002%	0.0002
4000467256	33050	78,175	8/26/2022	9/2/2022	7	0.021%	0.0014
4000467295	112215	8,332	8/30/2022	9/6/2022	7	0.002%	0.0002
4000467371	18267	5,080	8/31/2022	9/7/2022	7	0.001%	0.0001
4000467388	34064	240,371	8/31/2022	9/7/2022	7	0.063%	0.0044
4000467389	34088	8,336	8/31/2022	9/7/2022	7	0.002%	0.0002
4000467336	4765	38,660	8/31/2022	9/7/2022	7	0.010%	0.0007
4000467342	105195	36,608	8/31/2022	9/7/2022	7	0.010%	0.0007
4000467346	110506	10,000	8/31/2022	9/7/2022	7	0.003%	0.0002
4000467348	116384	155	8/31/2022	9/7/2022	7	0.000%	0.0000
4000467357	134862	1,395,622	8/31/2022	9/7/2022	7	0.368%	0.0258
4000467362	143588	22,834	8/31/2022	9/7/2022	7	0.006%	0.0004
4000467367	144878	2,716	8/31/2022	9/7/2022	7	0.001%	0.0001
4000467394	4502	5,057	9/1/2022	9/8/2022	7	0.001%	0.0001
4000467398	24825	2,114	9/1/2022	9/8/2022	7	0.001%	0.0000
4000467399	28348	6,728	9/1/2022	9/8/2022	7	0.002%	0.0001
4000467406	116384	73	9/1/2022	9/8/2022	7	0.000%	0.0000
4000467407	118807	75	9/1/2022	9/8/2022	7	0.000%	0.0000
4000467408	125742	12,600	9/1/2022	9/8/2022	7	0.003%	0.0002
4000467415	143577	7,730	9/1/2022	9/8/2022	7	0.002%	0.0001
4000467416	143796	56,896	9/1/2022	9/8/2022	7	0.015%	0.0011
4000467559	26604	36,860	9/6/2022	9/13/2022	7	0.010%	0.0007
4000467543	107191	161	9/6/2022	9/13/2022	7	0.000%	0.0000
4000467544	116384	170	9/6/2022	9/13/2022	7	0.000%	0.0000
4000467546	121853	4,135,826	9/6/2022	9/13/2022	7	1.091%	0.0764
4000467551	143072	40	9/6/2022	9/13/2022	7	0.000%	0.0000
4000467553	145059	2,000	9/6/2022	9/13/2022	7	0.001%	0.0000
4000467587	117331	6,000	9/7/2022	9/14/2022	7	0.002%	0.0001
4000467576	143072	212	9/7/2022	9/14/2022	7	0.000%	0.0000
4000467614	24999	3,384	9/8/2022	9/15/2022	7	0.001%	0.0001
4000467590	15871	22,029	9/8/2022	9/15/2022	7	0.006%	0.0004
4000467593	110291	14,014	9/8/2022	9/15/2022	7	0.004%	0.0003
4000467595	125742	2,140	9/8/2022	9/15/2022	7	0.001%	0.0000
4000467596	135194	101,696	9/8/2022	9/15/2022	7	0.027%	0.0019
4000467597	138494	1,785	9/8/2022	9/15/2022	7	0.000%	0.0000
4000467601	143072	3,186	9/8/2022	9/15/2022	7	0.001%	0.0001
4000467607	144567	22,603	9/8/2022	9/15/2022	7	0.006%	0.0004
4000467672	112215	4,166	9/12/2022	9/19/2022	7	0.001%	0.0001
4000467673	121853	743,775	9/12/2022	9/19/2022	7	0.196%	0.0137
4000467681	144480	30,608	9/12/2022	9/19/2022	7	0.008%	0.0006
4000467704	24281	7,797	9/13/2022	9/20/2022	7	0.002%	0.0001
4000467709	34064	232	9/13/2022	9/20/2022	7	0.000%	0.0000
4000467690	12081	53	9/13/2022	9/20/2022	7	0.000%	0.0000
4000467694	116384	79	9/13/2022	9/20/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467698	143659	1,702	9/13/2022	9/20/2022	7	0.000%	0.0000
4000467720	27094	3,532	9/14/2022	9/21/2022	7	0.001%	0.0001
4000467723	110291	10,786	9/14/2022	9/21/2022	7	0.003%	0.0002
4000467736	143312	80,735	9/14/2022	9/21/2022	7	0.021%	0.0015
4000467825	33956	9,391	9/15/2022	9/22/2022	7	0.002%	0.0002
4000467827	34064	125	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467830	117331	48,755	9/15/2022	9/22/2022	7	0.013%	0.0009
4000467832	126775	7,657	9/15/2022	9/22/2022	7	0.002%	0.0001
4000467777	15871	616	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467785	104154	1,056	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467786	104496	37	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467788	106840	114	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467790	110291	17,703	9/15/2022	9/22/2022	7	0.005%	0.0003
4000467791	110291	11,656	9/15/2022	9/22/2022	7	0.003%	0.0002
4000467794	116384	451	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467795	118807	107	9/15/2022	9/22/2022	7	0.000%	0.0000
4000467800	138494	10,200	9/15/2022	9/22/2022	7	0.003%	0.0002
4000467806	142926	147,568	9/15/2022	9/22/2022	7	0.039%	0.0027
4000467808	144860	9,000	9/15/2022	9/22/2022	7	0.002%	0.0002
4000467811	116971	3,000	9/15/2022	9/22/2022	7	0.001%	0.0001
4000467843	112215	6,249	9/16/2022	9/23/2022	7	0.002%	0.0001
4000467932	11305	30,919	9/20/2022	9/27/2022	7	0.008%	0.0006
4000467938	24385	1,195	9/20/2022	9/27/2022	7	0.000%	0.0000
4000467924	141822	1,582	9/20/2022	9/27/2022	7	0.000%	0.0000
4000467980	34894	5,418	9/21/2022	9/28/2022	7	0.001%	0.0001
4000467951	4502	9,723	9/21/2022	9/28/2022	7	0.003%	0.0002
4000467953	32842	530	9/21/2022	9/28/2022	7	0.000%	0.0000
4000467957	112215	198	9/21/2022	9/28/2022	7	0.000%	0.0000
4000467958	113857	9	9/21/2022	9/28/2022	7	0.000%	0.0000
4000467962	133414	1,397	9/21/2022	9/28/2022	7	0.000%	0.0000
4000467966	142942	1,529	9/21/2022	9/28/2022	7	0.000%	0.0000
4000467970	144567	23,328	9/21/2022	9/28/2022	7	0.006%	0.0004
4000467948	109222	130,400	9/21/2022	9/28/2022	7	0.034%	0.0024
4000468015	28474	786	9/22/2022	9/29/2022	7	0.000%	0.0000
4000467990	110291	16,843	9/22/2022	9/29/2022	7	0.004%	0.0003
4000467991	112215	1,560	9/22/2022	9/29/2022	7	0.000%	0.0000
4000467999	139982	9,494	9/22/2022	9/29/2022	7	0.003%	0.0002
4000468002	143072	10,798	9/22/2022	9/29/2022	7	0.003%	0.0002
4000468003	143577	6,718	9/22/2022	9/29/2022	7	0.002%	0.0001
4000468113	144097	8,041,426	9/26/2022	10/3/2022	7	2.121%	0.1485
4000468150	11305	40,647	9/27/2022	10/4/2022	7	0.011%	0.0008
4000468152	24385	4,921	9/27/2022	10/4/2022	7	0.001%	0.0001
4000468154	25808	15,480	9/27/2022	10/4/2022	7	0.004%	0.0003
4000468130	4502	9,317	9/27/2022	10/4/2022	7	0.002%	0.0002
4000468136	116384	31	9/27/2022	10/4/2022	7	0.000%	0.0000
4000468140	125742	14,361	9/27/2022	10/4/2022	7	0.004%	0.0003
4000468141	130315	39	9/27/2022	10/4/2022	7	0.000%	0.0000
4000468143	143011	4,450	9/27/2022	10/4/2022	7	0.001%	0.0001
4000468144	143340	6,201	9/27/2022	10/4/2022	7	0.002%	0.0001
4000468244	11305	854	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468250	26659	997	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468251	26674	3,360	9/28/2022	10/5/2022	7	0.001%	0.0001
4000468256	33956	14,757	9/28/2022	10/5/2022	7	0.004%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468206	105049	3,500	9/28/2022	10/5/2022	7	0.001%	0.0001
4000468208	107191	1,125	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468209	107389	5,000	9/28/2022	10/5/2022	7	0.001%	0.0001
4000468210	108149	283	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468211	110291	7,949	9/28/2022	10/5/2022	7	0.002%	0.0001
4000468214	111770	292	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468215	115761	59	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468225	129859	181,350	9/28/2022	10/5/2022	7	0.048%	0.0033
4000468228	134986	5,000	9/28/2022	10/5/2022	7	0.001%	0.0001
4000468233	143796	38,570	9/28/2022	10/5/2022	7	0.010%	0.0007
4000468236	144949	55	9/28/2022	10/5/2022	7	0.000%	0.0000
4000468298	26642	540	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468299	27013	1,440	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468302	30257	5,856	9/29/2022	10/6/2022	7	0.002%	0.0001
4000468303	30475	72,464	9/29/2022	10/6/2022	7	0.019%	0.0013
4000468304	30475	82,886	9/29/2022	10/6/2022	7	0.022%	0.0015
4000468305	33956	1,197	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468264	26958	66	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468266	103392	356	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468268	110291	23,511	9/29/2022	10/6/2022	7	0.006%	0.0004
4000468274	126775	2,879	9/29/2022	10/6/2022	7	0.001%	0.0001
4000468278	143072	955	9/29/2022	10/6/2022	7	0.000%	0.0000
4000468280	143659	38,380	9/29/2022	10/6/2022	7	0.010%	0.0007
4000468281	144097	5,217,213	9/29/2022	10/6/2022	7	1.376%	0.0963
4000468283	144567	4,829	9/29/2022	10/6/2022	7	0.001%	0.0001
4000468471	113563	15,568	10/4/2022	10/11/2022	7	0.004%	0.0003
4000468472	116384	15	10/4/2022	10/11/2022	7	0.000%	0.0000
4000468474	135194	20,239	10/4/2022	10/11/2022	7	0.005%	0.0004
4000468519	24383	1,935	10/6/2022	10/13/2022	7	0.001%	0.0000
4000468506	103392	213	10/6/2022	10/13/2022	7	0.000%	0.0000
4000468507	110291	30,179	10/6/2022	10/13/2022	7	0.008%	0.0006
4000468508	112215	3,146	10/6/2022	10/13/2022	7	0.001%	0.0001
4000468509	116384	60	10/6/2022	10/13/2022	7	0.000%	0.0000
4000468515	143659	13,295	10/6/2022	10/13/2022	7	0.004%	0.0002
4000468516	144567	8,500	10/6/2022	10/13/2022	7	0.002%	0.0002
4000468648	24385	8,085	10/11/2022	10/18/2022	7	0.002%	0.0001
4000468653	26604	18,700	10/11/2022	10/18/2022	7	0.005%	0.0003
4000468656	26674	2,240	10/11/2022	10/18/2022	7	0.001%	0.0000
4000468622	103392	1,290	10/11/2022	10/18/2022	7	0.000%	0.0000
4000468636	144567	19,930	10/11/2022	10/18/2022	7	0.005%	0.0004
4000468724	24113	7,595	10/12/2022	10/19/2022	7	0.002%	0.0001
4000468676	20287	220	10/12/2022	10/19/2022	7	0.000%	0.0000
4000468677	27094	8,829	10/12/2022	10/19/2022	7	0.002%	0.0002
4000468679	32842	1,943	10/12/2022	10/19/2022	7	0.001%	0.0000
4000468698	125904	3,000	10/12/2022	10/19/2022	7	0.001%	0.0001
4000468701	132094	4,909	10/12/2022	10/19/2022	7	0.001%	0.0001
4000468707	138862	60	10/12/2022	10/19/2022	7	0.000%	0.0000
4000468714	144567	1,960	10/12/2022	10/19/2022	7	0.001%	0.0000
4000468715	144679	13,331	10/12/2022	10/19/2022	7	0.004%	0.0002
4000468812	143694	10,008	10/14/2022	10/21/2022	7	0.003%	0.0002
4000468868	143796	69,881	10/17/2022	10/24/2022	7	0.018%	0.0013
4000468924	18267	1,792	10/18/2022	10/25/2022	7	0.000%	0.0000
4000468925	24383	890	10/18/2022	10/25/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468933	34064	50,298	10/18/2022	10/25/2022	7	0.013%	0.0009
4000468898	28348	2,185	10/18/2022	10/25/2022	7	0.001%	0.0000
4000468909	116384	660	10/18/2022	10/25/2022	7	0.000%	0.0000
4000468916	141826	20,329	10/18/2022	10/25/2022	7	0.005%	0.0004
4000468918	143154	1,187	10/18/2022	10/25/2022	7	0.000%	0.0000
4000468955	25083	908	10/19/2022	10/26/2022	7	0.000%	0.0000
4000468968	34064	263	10/19/2022	10/26/2022	7	0.000%	0.0000
4000468970	117331	3,000	10/19/2022	10/26/2022	7	0.001%	0.0001
4000468939	110291	12,252	10/19/2022	10/26/2022	7	0.003%	0.0002
4000468940	116384	49	10/19/2022	10/26/2022	7	0.000%	0.0000
4000468942	118807	1,717	10/19/2022	10/26/2022	7	0.000%	0.0000
4000468977	32950	48,868	10/19/2022	10/26/2022	7	0.013%	0.0009
4000468982	32970	69,889	10/19/2022	10/26/2022	7	0.018%	0.0013
4000468983	32973	252	10/19/2022	10/26/2022	7	0.000%	0.0000
4000468985	32979	8,047	10/19/2022	10/26/2022	7	0.002%	0.0001
4000468995	33014	32,756	10/19/2022	10/26/2022	7	0.009%	0.0006
4000469001	33031	26,916	10/19/2022	10/26/2022	7	0.007%	0.0005
4000469004	33040	329	10/19/2022	10/26/2022	7	0.000%	0.0000
4000469005	33041	20,671	10/19/2022	10/26/2022	7	0.005%	0.0004
4000469014	33075	44,726	10/19/2022	10/26/2022	7	0.012%	0.0008
4000469028	33146	10,031	10/19/2022	10/26/2022	7	0.003%	0.0002
4000469056	14949	4,591	10/20/2022	10/27/2022	7	0.001%	0.0001
4000469057	16321	6,800	10/20/2022	10/27/2022	7	0.002%	0.0001
4000469067	34064	255	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469072	117331	9,900	10/20/2022	10/27/2022	7	0.003%	0.0002
4000469073	124943	1,093	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469034	20287	275	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469038	104154	90	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469040	108149	100	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469041	110291	13,332	10/20/2022	10/27/2022	7	0.004%	0.0002
4000469045	130315	39	10/20/2022	10/27/2022	7	0.000%	0.0000
4000469052	143577	7,417	10/20/2022	10/27/2022	7	0.002%	0.0001
4000469054	144097	2,455,236	10/20/2022	10/27/2022	7	0.648%	0.0453
4000469129	108054	60	10/24/2022	10/31/2022	7	0.000%	0.0000
4000469130	108054	300	10/24/2022	10/31/2022	7	0.000%	0.0000
4000469131	108054	60	10/24/2022	10/31/2022	7	0.000%	0.0000
4000469132	108054	300	10/24/2022	10/31/2022	7	0.000%	0.0000
4000469183	142942	9,069	10/25/2022	11/1/2022	7	0.002%	0.0002
4000469252	117331	5,450	10/26/2022	11/2/2022	7	0.001%	0.0001
4000469218	119733	2,000	10/26/2022	11/2/2022	7	0.001%	0.0000
4000469219	119839	10,000	10/26/2022	11/2/2022	7	0.003%	0.0002
4000469229	144567	8,308	10/26/2022	11/2/2022	7	0.002%	0.0002
4000469230	145093	4,008	10/26/2022	11/2/2022	7	0.001%	0.0001
4000469310	26674	1,680	10/27/2022	11/3/2022	7	0.000%	0.0000
4000469316	33956	645	10/27/2022	11/3/2022	7	0.000%	0.0000
4000469260	4502	50,864	10/27/2022	11/3/2022	7	0.013%	0.0009
4000469261	4502	10,434	10/27/2022	11/3/2022	7	0.003%	0.0002
4000469264	24383	4,800	10/27/2022	11/3/2022	7	0.001%	0.0001
4000469272	115761	48	10/27/2022	11/3/2022	7	0.000%	0.0000
4000469275	125951	52	10/27/2022	11/3/2022	7	0.000%	0.0000
4000469278	129859	21,391	10/27/2022	11/3/2022	7	0.006%	0.0004
4000469288	144567	1,988	10/27/2022	11/3/2022	7	0.001%	0.0000
4000469424	143072	43,153	10/31/2022	11/7/2022	7	0.011%	0.0008

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469484	33956	1,178	11/1/2022	11/8/2022	7	0.000%	0.0000
4000469456	4502	882	11/1/2022	11/8/2022	7	0.000%	0.0000
4000469457	4502	26,923	11/1/2022	11/8/2022	7	0.007%	0.0005
4000469458	24383	3,560	11/1/2022	11/8/2022	7	0.001%	0.0001
4000469466	143011	475	11/1/2022	11/8/2022	7	0.000%	0.0000
4000469467	143477	19,356	11/1/2022	11/8/2022	7	0.005%	0.0004
4000469545	117331	12,045	11/2/2022	11/9/2022	7	0.003%	0.0002
4000469488	3970	835	11/2/2022	11/9/2022	7	0.000%	0.0000
4000469490	27094	112,924	11/2/2022	11/9/2022	7	0.030%	0.0021
4000469491	103392	1,009	11/2/2022	11/9/2022	7	0.000%	0.0000
4000469495	118807	673	11/2/2022	11/9/2022	7	0.000%	0.0000
4000469504	141370	13,250	11/2/2022	11/9/2022	7	0.003%	0.0002
4000469508	142162	11,000	11/2/2022	11/9/2022	7	0.003%	0.0002
4000469510	142787	10,565	11/2/2022	11/9/2022	7	0.003%	0.0002
4000469518	144479	45,000	11/2/2022	11/9/2022	7	0.012%	0.0008
4000469520	144567	7,000	11/2/2022	11/9/2022	7	0.002%	0.0001
4000469522	144773	625	11/2/2022	11/9/2022	7	0.000%	0.0000
4000469588	27305	3,500	11/3/2022	11/10/2022	7	0.001%	0.0001
4000469593	33956	4,773	11/3/2022	11/10/2022	7	0.001%	0.0001
4000469552	28084	42,085	11/3/2022	11/10/2022	7	0.011%	0.0008
4000469555	110291	49,070	11/3/2022	11/10/2022	7	0.013%	0.0009
4000469556	110291	57,127	11/3/2022	11/10/2022	7	0.015%	0.0011
4000469558	118807	62	11/3/2022	11/10/2022	7	0.000%	0.0000
4000469559	132094	21,481	11/3/2022	11/10/2022	7	0.006%	0.0004
4000469564	142635	46,224	11/3/2022	11/10/2022	7	0.012%	0.0009
4000469568	143577	6,587	11/3/2022	11/10/2022	7	0.002%	0.0001
4000469689	104154	544	11/8/2022	11/15/2022	7	0.000%	0.0000
4000469691	116384	470	11/8/2022	11/15/2022	7	0.000%	0.0000
4000469695	143011	11,731	11/8/2022	11/15/2022	7	0.003%	0.0002
4000469698	144567	4,189	11/8/2022	11/15/2022	7	0.001%	0.0001
4000469700	145411	1,498	11/8/2022	11/15/2022	7	0.000%	0.0000
4000469750	24383	1,938	11/9/2022	11/16/2022	7	0.001%	0.0000
4000469755	26296	588	11/9/2022	11/16/2022	7	0.000%	0.0000
4000469756	26363	3,086	11/9/2022	11/16/2022	7	0.001%	0.0001
4000469767	34389	10,000	11/9/2022	11/16/2022	7	0.003%	0.0002
4000469710	20287	426	11/9/2022	11/16/2022	7	0.000%	0.0000
4000469712	34888	1,625	11/9/2022	11/16/2022	7	0.000%	0.0000
4000469713	100577	12	11/9/2022	11/16/2022	7	0.000%	0.0000
4000469727	142653	2,000	11/9/2022	11/16/2022	7	0.001%	0.0000
4000469730	142942	4,842	11/9/2022	11/16/2022	7	0.001%	0.0001
4000469731	143659	50,840	11/9/2022	11/16/2022	7	0.013%	0.0009
4000469732	143659	156,519	11/9/2022	11/16/2022	7	0.041%	0.0029
4000469733	143920	111	11/9/2022	11/16/2022	7	0.000%	0.0000
4000469842	112215	30,417	11/14/2022	11/21/2022	7	0.008%	0.0006
4000469851	143072	4,413	11/14/2022	11/21/2022	7	0.001%	0.0001
4000469855	144281	4,000	11/14/2022	11/21/2022	7	0.001%	0.0001
4000469897	28474	6,788	11/15/2022	11/22/2022	7	0.002%	0.0001
4000469899	33956	5,546	11/15/2022	11/22/2022	7	0.001%	0.0001
4000469901	126775	54,611	11/15/2022	11/22/2022	7	0.014%	0.0010
4000469870	4502	10,987	11/15/2022	11/22/2022	7	0.003%	0.0002
4000469876	105195	2,138	11/15/2022	11/22/2022	7	0.001%	0.0000
4000469877	107191	57	11/15/2022	11/22/2022	7	0.000%	0.0000
4000469878	118807	565	11/15/2022	11/22/2022	7	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469880	137204	9,441	11/15/2022	11/22/2022	7	0.002%	0.0002
4000469881	138862	158	11/15/2022	11/22/2022	7	0.000%	0.0000
4000469884	143577	3,435	11/15/2022	11/22/2022	7	0.001%	0.0001
4000469885	144567	2,660	11/15/2022	11/22/2022	7	0.001%	0.0000
4000469887	144794	11,200	11/15/2022	11/22/2022	7	0.003%	0.0002
4000469888	144860	6,000	11/15/2022	11/22/2022	7	0.002%	0.0001
4000469936	29919	8,925	11/16/2022	11/23/2022	7	0.002%	0.0002
4000469951	33956	2,020	11/16/2022	11/23/2022	7	0.001%	0.0000
4000469954	117331	3,000	11/16/2022	11/23/2022	7	0.001%	0.0001
4000469908	116384	54	11/16/2022	11/23/2022	7	0.000%	0.0000
4000469918	143485	140,012	11/16/2022	11/23/2022	7	0.037%	0.0026
4000470064	126371	430,000	11/21/2022	11/28/2022	7	0.113%	0.0079
4000470133	10630	9,680	11/22/2022	11/29/2022	7	0.003%	0.0002
4000470310	126775	6,386	11/29/2022	12/6/2022	7	0.002%	0.0001
4000470281	103392	252	11/29/2022	12/6/2022	7	0.000%	0.0000
4000470282	105195	1,208	11/29/2022	12/6/2022	7	0.000%	0.0000
4000470290	143463	61,280	11/29/2022	12/6/2022	7	0.016%	0.0011
4000470291	143463	232,683	11/29/2022	12/6/2022	7	0.061%	0.0043
4000470350	18267	23,118	11/30/2022	12/7/2022	7	0.006%	0.0004
4000470361	26588	27,360	11/30/2022	12/7/2022	7	0.007%	0.0005
4000470369	30257	983	11/30/2022	12/7/2022	7	0.000%	0.0000
4000470378	33956	3,475	11/30/2022	12/7/2022	7	0.001%	0.0001
4000470380	34064	498	11/30/2022	12/7/2022	7	0.000%	0.0000
4000470384	34937	12,000	11/30/2022	12/7/2022	7	0.003%	0.0002
4000470385	105195	25,509	11/30/2022	12/7/2022	7	0.007%	0.0005
4000470315	26588	4,390	11/30/2022	12/7/2022	7	0.001%	0.0001
4000470316	27094	2,649	11/30/2022	12/7/2022	7	0.001%	0.0000
4000470318	28348	920	11/30/2022	12/7/2022	7	0.000%	0.0000
4000470319	32842	1,663	11/30/2022	12/7/2022	7	0.000%	0.0000
4000470322	118807	3,378	11/30/2022	12/7/2022	7	0.001%	0.0001
4000470329	133414	6,125	11/30/2022	12/7/2022	7	0.002%	0.0001
4000470332	143312	105,515	11/30/2022	12/7/2022	7	0.028%	0.0019
4000470333	143606	423,628	11/30/2022	12/7/2022	7	0.112%	0.0078
4000470334	143637	3,750	11/30/2022	12/7/2022	7	0.001%	0.0001
4000470339	144567	4,918	11/30/2022	12/7/2022	7	0.001%	0.0001
4000470434	24383	1,360	12/1/2022	12/8/2022	7	0.000%	0.0000
4000470439	27982	600	12/1/2022	12/8/2022	7	0.000%	0.0000
4000470397	26958	10,512	12/1/2022	12/8/2022	7	0.003%	0.0002
4000470398	36403	483	12/1/2022	12/8/2022	7	0.000%	0.0000
4000470406	118807	98	12/1/2022	12/8/2022	7	0.000%	0.0000
4000470419	142732	160,000	12/1/2022	12/8/2022	7	0.042%	0.0030
4000470424	143584	663,091	12/1/2022	12/8/2022	7	0.175%	0.0122
4000470428	144878	2,716	12/1/2022	12/8/2022	7	0.001%	0.0001
4000470583	142942	16,033	12/6/2022	12/13/2022	7	0.004%	0.0003
4000470634	26297	7,951	12/7/2022	12/14/2022	7	0.002%	0.0001
4000470636	26363	3,895	12/7/2022	12/14/2022	7	0.001%	0.0001
4000470639	26639	2,430	12/7/2022	12/14/2022	7	0.001%	0.0000
4000470641	26655	6,618	12/7/2022	12/14/2022	7	0.002%	0.0001
4000470643	34064	146	12/7/2022	12/14/2022	7	0.000%	0.0000
4000470606	104496	35	12/7/2022	12/14/2022	7	0.000%	0.0000
4000470612	125742	2,244	12/7/2022	12/14/2022	7	0.001%	0.0000
4000470673	24281	7,382	12/8/2022	12/15/2022	7	0.002%	0.0001
4000470678	26643	3,328	12/8/2022	12/15/2022	7	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470688	124943	380	12/8/2022	12/15/2022	7	0.000%	0.0000
4000470655	107794	269	12/8/2022	12/15/2022	7	0.000%	0.0000
4000470661	141610	335,387	12/8/2022	12/15/2022	7	0.088%	0.0062
4000470667	144917	9,900	12/8/2022	12/15/2022	7	0.003%	0.0002
4000470757	143796	6,408	12/12/2022	12/19/2022	7	0.002%	0.0001
4000470760	144760	11,621	12/12/2022	12/19/2022	7	0.003%	0.0002
4000470786	25093	1,023	12/13/2022	12/20/2022	7	0.000%	0.0000
4000470842	14949	1,444	12/14/2022	12/21/2022	7	0.000%	0.0000
4000470850	25908	7,500	12/14/2022	12/21/2022	7	0.002%	0.0001
4000470856	26674	6,580	12/14/2022	12/21/2022	7	0.002%	0.0001
4000470864	34335	300	12/14/2022	12/21/2022	7	0.000%	0.0000
4000470818	105195	1,383	12/14/2022	12/21/2022	7	0.000%	0.0000
4000470819	107191	30	12/14/2022	12/21/2022	7	0.000%	0.0000
4000470830	142635	47,794	12/14/2022	12/21/2022	7	0.013%	0.0009
4000470832	143312	4,392	12/14/2022	12/21/2022	7	0.001%	0.0001
4000470874	15871	2,370	12/15/2022	12/22/2022	7	0.001%	0.0000
4000470879	104122	12,301	12/15/2022	12/22/2022	7	0.003%	0.0002
4000470880	104122	6,420	12/15/2022	12/22/2022	7	0.002%	0.0001
4000470887	129387	53,105	12/15/2022	12/22/2022	7	0.014%	0.0010
4000470889	138494	54,400	12/15/2022	12/22/2022	7	0.014%	0.0010
4000470892	141065	25,000	12/15/2022	12/22/2022	7	0.007%	0.0005
4000470896	143312	36,009	12/15/2022	12/22/2022	7	0.009%	0.0007
4000470901	145501	7,763	12/15/2022	12/22/2022	7	0.002%	0.0001
4000471119	112215	7,137	12/21/2022	12/28/2022	7	0.002%	0.0001
4000471319	24385	1,951	12/28/2022	1/4/2023	7	0.001%	0.0000
4000471330	33956	6,736	12/28/2022	1/4/2023	7	0.002%	0.0001
4000471331	34088	21,362	12/28/2022	1/4/2023	7	0.006%	0.0004
4000471335	105195	4,229	12/28/2022	1/4/2023	7	0.001%	0.0001
4000471300	7214	465,360	12/28/2022	1/4/2023	7	0.123%	0.0086
4000471313	143463	88,000	12/28/2022	1/4/2023	7	0.023%	0.0016
4000471314	144567	3,460	12/28/2022	1/4/2023	7	0.001%	0.0001
4000471315	144816	4,452	12/28/2022	1/4/2023	7	0.001%	0.0001
4000471386	25708	1,715	12/29/2022	1/5/2023	7	0.000%	0.0000
4000471398	26604	10,270	12/29/2022	1/5/2023	7	0.003%	0.0002
4000471339	4502	358	12/29/2022	1/5/2023	7	0.000%	0.0000
4000471341	7214	931,990	12/29/2022	1/5/2023	7	0.246%	0.0172
4000471350	110291	1,488	12/29/2022	1/5/2023	7	0.000%	0.0000
4000471355	133414	355	12/29/2022	1/5/2023	7	0.000%	0.0000
4000471362	144097	271,562	12/29/2022	1/5/2023	7	0.072%	0.0050
4000459554	18267	5,594	1/3/2022	1/11/2022	8	0.001%	0.0001
4000459556	25716	5,772	1/3/2022	1/11/2022	8	0.002%	0.0001
4000459562	105195	717	1/3/2022	1/11/2022	8	0.000%	0.0000
4000459542	32842	3,069	1/3/2022	1/11/2022	8	0.001%	0.0001
4000459545	105195	2,929	1/3/2022	1/11/2022	8	0.001%	0.0001
4000459548	131510	76,100	1/3/2022	1/11/2022	8	0.020%	0.0016
4000459553	143606	61,919	1/3/2022	1/11/2022	8	0.016%	0.0013
4000459583	14060	17,068	1/4/2022	1/12/2022	8	0.005%	0.0004
4000459573	15871	806	1/4/2022	1/12/2022	8	0.000%	0.0000
4000459574	22798	2,625	1/4/2022	1/12/2022	8	0.001%	0.0001
4000459579	140752	20,875	1/4/2022	1/12/2022	8	0.006%	0.0004
4000459580	141101	10,800	1/4/2022	1/12/2022	8	0.003%	0.0002
4000459604	30228	373,271	1/5/2022	1/13/2022	8	0.098%	0.0079
4000459590	4909	1,080	1/5/2022	1/13/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459591	7214	170,178	1/5/2022	1/13/2022	8	0.045%	0.0036
4000459600	143694	269	1/5/2022	1/13/2022	8	0.000%	0.0000
4000459601	144847	15,000	1/5/2022	1/13/2022	8	0.004%	0.0003
4000459644	18267	3,068	1/6/2022	1/14/2022	8	0.001%	0.0001
4000459650	33956	6,168	1/6/2022	1/14/2022	8	0.002%	0.0001
4000459651	34064	3,467	1/6/2022	1/14/2022	8	0.001%	0.0001
4000459656	105195	3,730	1/6/2022	1/14/2022	8	0.001%	0.0001
4000459613	104496	37	1/6/2022	1/14/2022	8	0.000%	0.0000
4000459615	105195	10,711	1/6/2022	1/14/2022	8	0.003%	0.0002
4000459616	111770	274	1/6/2022	1/14/2022	8	0.000%	0.0000
4000459623	132094	1,604	1/6/2022	1/14/2022	8	0.000%	0.0000
4000459632	143659	129,090	1/6/2022	1/14/2022	8	0.034%	0.0027
4000459633	143659	20,103	1/6/2022	1/14/2022	8	0.005%	0.0004
4000459640	144567	1,595	1/6/2022	1/14/2022	8	0.000%	0.0000
4000459736	34658	3,600	1/10/2022	1/18/2022	8	0.001%	0.0001
4000459769	34658	2,000	1/11/2022	1/19/2022	8	0.001%	0.0000
4000459743	34888	177	1/11/2022	1/19/2022	8	0.000%	0.0000
4000459753	144084	3,980	1/11/2022	1/19/2022	8	0.001%	0.0001
4000459790	24281	1,714	1/12/2022	1/20/2022	8	0.000%	0.0000
4000459792	24825	1,333	1/12/2022	1/20/2022	8	0.000%	0.0000
4000459793	25808	28,950	1/12/2022	1/20/2022	8	0.008%	0.0006
4000459797	27013	941	1/12/2022	1/20/2022	8	0.000%	0.0000
4000459800	33975	3,533	1/12/2022	1/20/2022	8	0.001%	0.0001
4000459804	117331	3,250	1/12/2022	1/20/2022	8	0.001%	0.0001
4000459807	126775	44,247	1/12/2022	1/20/2022	8	0.012%	0.0009
4000459776	15871	2,479	1/12/2022	1/20/2022	8	0.001%	0.0001
4000459780	140752	5,249	1/12/2022	1/20/2022	8	0.001%	0.0001
4000459982	1908	26,094	1/18/2022	1/26/2022	8	0.007%	0.0006
4000459994	24825	6,122	1/18/2022	1/26/2022	8	0.002%	0.0001
4000459995	25716	2,235	1/18/2022	1/26/2022	8	0.001%	0.0000
4000459997	26643	9,423	1/18/2022	1/26/2022	8	0.002%	0.0002
4000459998	27013	6,195	1/18/2022	1/26/2022	8	0.002%	0.0001
4000459999	28084	2,470	1/18/2022	1/26/2022	8	0.001%	0.0001
4000460010	117331	10,334	1/18/2022	1/26/2022	8	0.003%	0.0002
4000459957	15871	8,249	1/18/2022	1/26/2022	8	0.002%	0.0002
4000459959	24825	970	1/18/2022	1/26/2022	8	0.000%	0.0000
4000459967	135488	27,724	1/18/2022	1/26/2022	8	0.007%	0.0006
4000459975	144084	11,580	1/18/2022	1/26/2022	8	0.003%	0.0002
4000459978	144663	10,900	1/18/2022	1/26/2022	8	0.003%	0.0002
4000460032	11577	4,725	1/19/2022	1/27/2022	8	0.001%	0.0001
4000460035	24259	2,248	1/19/2022	1/27/2022	8	0.001%	0.0000
4000460037	24383	1,048	1/19/2022	1/27/2022	8	0.000%	0.0000
4000460044	33238	840	1/19/2022	1/27/2022	8	0.000%	0.0000
4000460048	34341	9,450	1/19/2022	1/27/2022	8	0.002%	0.0002
4000460027	144421	303,614	1/19/2022	1/27/2022	8	0.080%	0.0064
4000460085	25716	11,879	1/20/2022	1/28/2022	8	0.003%	0.0003
4000460093	30773	3,802	1/20/2022	1/28/2022	8	0.001%	0.0001
4000460097	34064	437	1/20/2022	1/28/2022	8	0.000%	0.0000
4000460055	10055	392	1/20/2022	1/28/2022	8	0.000%	0.0000
4000460056	15871	4,784	1/20/2022	1/28/2022	8	0.001%	0.0001
4000460060	100577	8,690	1/20/2022	1/28/2022	8	0.002%	0.0002
4000460068	125742	5,136	1/20/2022	1/28/2022	8	0.001%	0.0001
4000460069	126653	105,437	1/20/2022	1/28/2022	8	0.028%	0.0022

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460071	133414	1,904	1/20/2022	1/28/2022	8	0.001%	0.0000
4000460072	134664	3,413	1/20/2022	1/28/2022	8	0.001%	0.0001
4000460074	143111	1,600	1/20/2022	1/28/2022	8	0.000%	0.0000
4000460150	11305	11,461	1/24/2022	2/1/2022	8	0.003%	0.0002
4000460171	32976	5,749	1/24/2022	2/1/2022	8	0.002%	0.0001
4000460172	32979	15,300	1/24/2022	2/1/2022	8	0.004%	0.0003
4000460183	33014	64,511	1/24/2022	2/1/2022	8	0.017%	0.0014
4000460184	33015	12,536	1/24/2022	2/1/2022	8	0.003%	0.0003
4000460185	33017	12,837	1/24/2022	2/1/2022	8	0.003%	0.0003
4000460186	33018	90,479	1/24/2022	2/1/2022	8	0.024%	0.0019
4000460189	33026	1,384	1/24/2022	2/1/2022	8	0.000%	0.0000
4000460196	33036	21,895	1/24/2022	2/1/2022	8	0.006%	0.0005
4000460199	33040	663	1/24/2022	2/1/2022	8	0.000%	0.0000
4000460200	33041	27,489	1/24/2022	2/1/2022	8	0.007%	0.0006
4000460204	33048	6,964	1/24/2022	2/1/2022	8	0.002%	0.0001
4000460209	33054	32,918	1/24/2022	2/1/2022	8	0.009%	0.0007
4000460218	33064	63,646	1/24/2022	2/1/2022	8	0.017%	0.0013
4000460221	33085	12,716	1/24/2022	2/1/2022	8	0.003%	0.0003
4000460268	30773	1,961	1/25/2022	2/2/2022	8	0.001%	0.0000
4000460227	15871	5,011	1/25/2022	2/2/2022	8	0.001%	0.0001
4000460237	116384	15	1/25/2022	2/2/2022	8	0.000%	0.0000
4000460239	132094	100	1/25/2022	2/2/2022	8	0.000%	0.0000
4000460245	143577	7,808	1/25/2022	2/2/2022	8	0.002%	0.0002
4000460292	14060	19,526	1/26/2022	2/3/2022	8	0.005%	0.0004
4000460294	25131	4,655	1/26/2022	2/3/2022	8	0.001%	0.0001
4000460299	27013	3,766	1/26/2022	2/3/2022	8	0.001%	0.0001
4000460306	117331	35,500	1/26/2022	2/3/2022	8	0.009%	0.0007
4000460279	108289	271	1/26/2022	2/3/2022	8	0.000%	0.0000
4000460285	143340	25,500	1/26/2022	2/3/2022	8	0.007%	0.0005
4000460286	143588	10,670	1/26/2022	2/3/2022	8	0.003%	0.0002
4000460434	26659	78,813	1/27/2022	2/4/2022	8	0.021%	0.0017
4000460435	27013	27,783	1/27/2022	2/4/2022	8	0.007%	0.0006
4000460445	117331	3,000	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460313	15871	5,303	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460318	103008	614	1/27/2022	2/4/2022	8	0.000%	0.0000
4000460319	103392	48	1/27/2022	2/4/2022	8	0.000%	0.0000
4000460324	123915	750	1/27/2022	2/4/2022	8	0.000%	0.0000
4000460325	125742	5,136	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460327	133414	7,110	1/27/2022	2/4/2022	8	0.002%	0.0002
4000460329	139503	262,279	1/27/2022	2/4/2022	8	0.069%	0.0055
4000460338	144691	6,954	1/27/2022	2/4/2022	8	0.002%	0.0001
4000460348	33016	56,433	1/27/2022	2/4/2022	8	0.015%	0.0012
4000460356	33070	17,355	1/27/2022	2/4/2022	8	0.005%	0.0004
4000460357	33071	170,949	1/27/2022	2/4/2022	8	0.045%	0.0036
4000460359	33073	2,349	1/27/2022	2/4/2022	8	0.001%	0.0000
4000460367	33083	55,642	1/27/2022	2/4/2022	8	0.015%	0.0012
4000460368	33084	1,307	1/27/2022	2/4/2022	8	0.000%	0.0000
4000460370	33090	11,693	1/27/2022	2/4/2022	8	0.003%	0.0002
4000460371	33092	10,977	1/27/2022	2/4/2022	8	0.003%	0.0002
4000460373	33094	4,517	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460375	33096	8,776	1/27/2022	2/4/2022	8	0.002%	0.0002
4000460377	33098	37,084	1/27/2022	2/4/2022	8	0.010%	0.0008
4000460379	33101	724	1/27/2022	2/4/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460390	33116	3,350	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460391	33117	49,063	1/27/2022	2/4/2022	8	0.013%	0.0010
4000460392	33119	5,779	1/27/2022	2/4/2022	8	0.002%	0.0001
4000460393	33120	44,563	1/27/2022	2/4/2022	8	0.012%	0.0009
4000460394	33121	2,449	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460395	33122	21,585	1/27/2022	2/4/2022	8	0.006%	0.0005
4000460396	33123	778	1/27/2022	2/4/2022	8	0.000%	0.0000
4000460397	33125	3,027	1/27/2022	2/4/2022	8	0.001%	0.0001
4000460403	33131	40,775	1/27/2022	2/4/2022	8	0.011%	0.0009
4000460407	33135	7,535	1/27/2022	2/4/2022	8	0.002%	0.0002
4000460417	33146	10,049	1/27/2022	2/4/2022	8	0.003%	0.0002
4000460419	33148	1,967	1/27/2022	2/4/2022	8	0.001%	0.0000
4000460587	14949	12,519	1/31/2022	2/8/2022	8	0.003%	0.0003
4000460588	17342	1,620	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460593	25083	683	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460601	26338	1,071	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460607	26642	1,439	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460609	26659	61,319	1/31/2022	2/8/2022	8	0.016%	0.0013
4000460614	126775	9,541	1/31/2022	2/8/2022	8	0.003%	0.0002
4000460566	32842	3,244	1/31/2022	2/8/2022	8	0.001%	0.0001
4000460570	118807	125	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460573	132094	100	1/31/2022	2/8/2022	8	0.000%	0.0000
4000460579	143606	6,629	1/31/2022	2/8/2022	8	0.002%	0.0001
4000460582	144687	3,163	1/31/2022	2/8/2022	8	0.001%	0.0001
4000460673	33770	57,846	2/1/2022	2/9/2022	8	0.015%	0.0012
4000460622	100335	4,102	2/1/2022	2/9/2022	8	0.001%	0.0001
4000460625	116718	9,057	2/1/2022	2/9/2022	8	0.002%	0.0002
4000460626	116850	431	2/1/2022	2/9/2022	8	0.000%	0.0000
4000460631	134862	44,234	2/1/2022	2/9/2022	8	0.012%	0.0009
4000460632	134906	3,900	2/1/2022	2/9/2022	8	0.001%	0.0001
4000460636	139982	9,434	2/1/2022	2/9/2022	8	0.002%	0.0002
4000460647	142607	2,500	2/1/2022	2/9/2022	8	0.001%	0.0001
4000460648	142700	4,243	2/1/2022	2/9/2022	8	0.001%	0.0001
4000460649	142787	10,258	2/1/2022	2/9/2022	8	0.003%	0.0002
4000460655	143364	12,300	2/1/2022	2/9/2022	8	0.003%	0.0003
4000460657	143867	28,480	2/1/2022	2/9/2022	8	0.008%	0.0006
4000460659	144015	10,000	2/1/2022	2/9/2022	8	0.003%	0.0002
4000460660	144031	1,500	2/1/2022	2/9/2022	8	0.000%	0.0000
4000460708	25716	510	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460709	26213	736	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460711	28084	2,898	2/2/2022	2/10/2022	8	0.001%	0.0001
4000460713	30475	51,958	2/2/2022	2/10/2022	8	0.014%	0.0011
4000460714	30475	37,618	2/2/2022	2/10/2022	8	0.010%	0.0008
4000460715	30475	45,759	2/2/2022	2/10/2022	8	0.012%	0.0010
4000460716	32808	440	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460675	4765	3,000	2/2/2022	2/10/2022	8	0.001%	0.0001
4000460679	103392	294	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460682	112215	3,432	2/2/2022	2/10/2022	8	0.001%	0.0001
4000460686	125742	3,912	2/2/2022	2/10/2022	8	0.001%	0.0001
4000460697	143436	836	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460698	143477	4,424	2/2/2022	2/10/2022	8	0.001%	0.0001
4000460701	143944	1,272	2/2/2022	2/10/2022	8	0.000%	0.0000
4000460703	144483	168,262	2/2/2022	2/10/2022	8	0.044%	0.0036

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460743	11536	17,135	2/3/2022	2/11/2022	8	0.005%	0.0004
4000460751	27013	5,505	2/3/2022	2/11/2022	8	0.001%	0.0001
4000460762	135537	5,148	2/3/2022	2/11/2022	8	0.001%	0.0001
4000460728	103008	3,095	2/3/2022	2/11/2022	8	0.001%	0.0001
4000460729	103392	1,426	2/3/2022	2/11/2022	8	0.000%	0.0000
4000460730	104872	819	2/3/2022	2/11/2022	8	0.000%	0.0000
4000460721	101122	2,400	2/3/2022	2/11/2022	8	0.001%	0.0001
4000460723	126356	1,138	2/3/2022	2/11/2022	8	0.000%	0.0000
4000460833	17342	6,075	2/7/2022	2/15/2022	8	0.002%	0.0001
4000460835	24383	4,080	2/7/2022	2/15/2022	8	0.001%	0.0001
4000460836	24385	14,463	2/7/2022	2/15/2022	8	0.004%	0.0003
4000460841	26642	3,180	2/7/2022	2/15/2022	8	0.001%	0.0001
4000460843	26674	3,570	2/7/2022	2/15/2022	8	0.001%	0.0001
4000460844	27982	2,100	2/7/2022	2/15/2022	8	0.001%	0.0000
4000460846	32356	1,350	2/7/2022	2/15/2022	8	0.000%	0.0000
4000460849	34658	5,680	2/7/2022	2/15/2022	8	0.001%	0.0001
4000460814	116384	4	2/7/2022	2/15/2022	8	0.000%	0.0000
4000460818	126632	1,946	2/7/2022	2/15/2022	8	0.001%	0.0000
4000460877	17342	2,700	2/8/2022	2/16/2022	8	0.001%	0.0001
4000460855	104872	134	2/8/2022	2/16/2022	8	0.000%	0.0000
4000460856	111770	274	2/8/2022	2/16/2022	8	0.000%	0.0000
4000460861	124753	1,282	2/8/2022	2/16/2022	8	0.000%	0.0000
4000460866	129203	1,803	2/8/2022	2/16/2022	8	0.000%	0.0000
4000460869	134811	1,375	2/8/2022	2/16/2022	8	0.000%	0.0000
4000460902	11372	1,940	2/9/2022	2/17/2022	8	0.001%	0.0000
4000460913	28530	4,825	2/9/2022	2/17/2022	8	0.001%	0.0001
4000460914	29662	800	2/9/2022	2/17/2022	8	0.000%	0.0000
4000460893	141260	1,635	2/9/2022	2/17/2022	8	0.000%	0.0000
4000460897	144410	18,810	2/9/2022	2/17/2022	8	0.005%	0.0004
4000460954	11577	2,153	2/10/2022	2/18/2022	8	0.001%	0.0000
4000460961	26639	6,480	2/10/2022	2/18/2022	8	0.002%	0.0001
4000460962	26643	14,755	2/10/2022	2/18/2022	8	0.004%	0.0003
4000460934	15871	1,530	2/10/2022	2/18/2022	8	0.000%	0.0000
4000460936	102504	96	2/10/2022	2/18/2022	8	0.000%	0.0000
4000460937	103471	2,049	2/10/2022	2/18/2022	8	0.001%	0.0000
4000460948	143154	99,664	2/10/2022	2/18/2022	8	0.026%	0.0021
4000460949	143477	1,654	2/10/2022	2/18/2022	8	0.000%	0.0000
4000460929	127614	10,500	2/10/2022	2/18/2022	8	0.003%	0.0002
4000461096	32564	9,700	2/15/2022	2/23/2022	8	0.003%	0.0002
4000461097	105195	16,107	2/15/2022	2/23/2022	8	0.004%	0.0003
4000461081	27094	2,649	2/15/2022	2/23/2022	8	0.001%	0.0001
4000461082	32842	1,563	2/15/2022	2/23/2022	8	0.000%	0.0000
4000461083	101283	9,677	2/15/2022	2/23/2022	8	0.003%	0.0002
4000461086	115761	45	2/15/2022	2/23/2022	8	0.000%	0.0000
4000461088	118807	11	2/15/2022	2/23/2022	8	0.000%	0.0000
4000461089	133565	339,848	2/15/2022	2/23/2022	8	0.090%	0.0072
4000461090	142269	3,500	2/15/2022	2/23/2022	8	0.001%	0.0001
4000461092	144093	1,734	2/15/2022	2/23/2022	8	0.000%	0.0000
4000461093	116971	3,000	2/15/2022	2/23/2022	8	0.001%	0.0001
4000461151	27013	1,915	2/16/2022	2/24/2022	8	0.001%	0.0000
4000461152	28084	12,730	2/16/2022	2/24/2022	8	0.003%	0.0003
4000461153	28530	1,694	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461154	30475	25,896	2/16/2022	2/24/2022	8	0.007%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461158	117331	45,800	2/16/2022	2/24/2022	8	0.012%	0.0010
4000461103	13672	1,500	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461108	103392	26	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461113	109456	500	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461117	116051	300	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461121	126481	10,000	2/16/2022	2/24/2022	8	0.003%	0.0002
4000461134	142874	4,586	2/16/2022	2/24/2022	8	0.001%	0.0001
4000461136	143221	1,000	2/16/2022	2/24/2022	8	0.000%	0.0000
4000461192	25131	2,090	2/17/2022	2/25/2022	8	0.001%	0.0000
4000461198	30475	66,326	2/17/2022	2/25/2022	8	0.017%	0.0014
4000461199	30475	47,735	2/17/2022	2/25/2022	8	0.013%	0.0010
4000461200	30475	55,277	2/17/2022	2/25/2022	8	0.015%	0.0012
4000461164	24856	3,410	2/17/2022	2/25/2022	8	0.001%	0.0001
4000461175	133414	2,839	2/17/2022	2/25/2022	8	0.001%	0.0001
4000461181	143477	3,300	2/17/2022	2/25/2022	8	0.001%	0.0001
4000461295	11260	1,538	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461297	24251	9,000	2/22/2022	3/2/2022	8	0.002%	0.0002
4000461300	25659	590	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461301	26659	1,733	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461308	32853	495	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461309	32875	1,100	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461266	103392	316	2/22/2022	3/2/2022	8	0.000%	0.0000
4000461271	116051	3,009	2/22/2022	3/2/2022	8	0.001%	0.0001
4000461286	140752	5,537	2/22/2022	3/2/2022	8	0.001%	0.0001
4000461290	143342	10,000	2/22/2022	3/2/2022	8	0.003%	0.0002
4000461340	11304	20,625	2/23/2022	3/3/2022	8	0.005%	0.0004
4000461342	11372	1,764	2/23/2022	3/3/2022	8	0.000%	0.0000
4000461345	24825	4,850	2/23/2022	3/3/2022	8	0.001%	0.0001
4000461346	25599	6,690	2/23/2022	3/3/2022	8	0.002%	0.0001
4000461347	25708	2,652	2/23/2022	3/3/2022	8	0.001%	0.0001
4000461352	26338	871	2/23/2022	3/3/2022	8	0.000%	0.0000
4000461357	26655	3,623	2/23/2022	3/3/2022	8	0.001%	0.0001
4000461358	26659	70,623	2/23/2022	3/3/2022	8	0.019%	0.0015
4000461360	27013	14,085	2/23/2022	3/3/2022	8	0.004%	0.0003
4000461362	27803	52,920	2/23/2022	3/3/2022	8	0.014%	0.0011
4000461333	140752	1,769	2/23/2022	3/3/2022	8	0.000%	0.0000
4000461391	5673	720	2/24/2022	3/4/2022	8	0.000%	0.0000
4000461395	25131	1,283	2/24/2022	3/4/2022	8	0.000%	0.0000
4000461399	27962	945	2/24/2022	3/4/2022	8	0.000%	0.0000
4000461380	142635	15,567	2/24/2022	3/4/2022	8	0.004%	0.0003
4000461387	143941	2,100	2/24/2022	3/4/2022	8	0.001%	0.0000
4000461388	144097	831,720	2/24/2022	3/4/2022	8	0.219%	0.0175
4000461390	144794	11,000	2/24/2022	3/4/2022	8	0.003%	0.0002
4000461505	25708	30,578	2/28/2022	3/8/2022	8	0.008%	0.0006
4000461470	26674	1,120	2/28/2022	3/8/2022	8	0.000%	0.0000
4000461475	103392	66	2/28/2022	3/8/2022	8	0.000%	0.0000
4000461480	109523	15,000	2/28/2022	3/8/2022	8	0.004%	0.0003
4000461490	141091	1,017	2/28/2022	3/8/2022	8	0.000%	0.0000
4000461521	4502	6,730	3/1/2022	3/9/2022	8	0.002%	0.0001
4000461523	116384	8	3/1/2022	3/9/2022	8	0.000%	0.0000
4000461527	143433	3,069	3/1/2022	3/9/2022	8	0.001%	0.0001
4000461530	144791	5,200	3/1/2022	3/9/2022	8	0.001%	0.0001
4000461535	126711	7,686	3/2/2022	3/10/2022	8	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461549	117392	2,130	3/2/2022	3/10/2022	8	0.001%	0.0000
4000461554	133414	8,782	3/2/2022	3/10/2022	8	0.002%	0.0002
4000461556	136045	42,000	3/2/2022	3/10/2022	8	0.011%	0.0009
4000461586	144687	873	3/2/2022	3/10/2022	8	0.000%	0.0000
4000461703	10384	2,500	3/7/2022	3/15/2022	8	0.001%	0.0001
4000461706	126775	1,972	3/7/2022	3/15/2022	8	0.001%	0.0000
4000461677	17293	6,000	3/7/2022	3/15/2022	8	0.002%	0.0001
4000461685	113528	500	3/7/2022	3/15/2022	8	0.000%	0.0000
4000461688	116384	4	3/7/2022	3/15/2022	8	0.000%	0.0000
4000461691	118807	65	3/7/2022	3/15/2022	8	0.000%	0.0000
4000461692	132094	1,391	3/7/2022	3/15/2022	8	0.000%	0.0000
4000461728	26639	2,565	3/8/2022	3/16/2022	8	0.001%	0.0001
4000461708	26588	840	3/8/2022	3/16/2022	8	0.000%	0.0000
4000461709	27094	17,658	3/8/2022	3/16/2022	8	0.005%	0.0004
4000461710	103392	311	3/8/2022	3/16/2022	8	0.000%	0.0000
4000461711	103404	51	3/8/2022	3/16/2022	8	0.000%	0.0000
4000461715	111669	86	3/8/2022	3/16/2022	8	0.000%	0.0000
4000461718	125783	425	3/8/2022	3/16/2022	8	0.000%	0.0000
4000461737	4765	11,000	3/9/2022	3/17/2022	8	0.003%	0.0002
4000461738	6396	33,335	3/9/2022	3/17/2022	8	0.009%	0.0007
4000461740	102553	147	3/9/2022	3/17/2022	8	0.000%	0.0000
4000461742	118807	653	3/9/2022	3/17/2022	8	0.000%	0.0000
4000461764	4502	33,650	3/10/2022	3/18/2022	8	0.009%	0.0007
4000461776	142942	3,594	3/10/2022	3/18/2022	8	0.001%	0.0001
4000461781	143796	1,230	3/10/2022	3/18/2022	8	0.000%	0.0000
4000461857	116384	261	3/14/2022	3/22/2022	8	0.000%	0.0000
4000461864	132301	1,000	3/14/2022	3/22/2022	8	0.000%	0.0000
4000461905	24281	605	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461913	26659	23,500	3/15/2022	3/23/2022	8	0.006%	0.0005
4000461921	33747	489	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461923	34531	2,876	3/15/2022	3/23/2022	8	0.001%	0.0001
4000461879	102637	121	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461880	103114	26	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461881	103392	27	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461882	104496	38	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461890	129783	159	3/15/2022	3/23/2022	8	0.000%	0.0000
4000461946	24191	212	3/16/2022	3/24/2022	8	0.000%	0.0000
4000461949	25905	7,100	3/16/2022	3/24/2022	8	0.002%	0.0001
4000461950	26453	2,320	3/16/2022	3/24/2022	8	0.001%	0.0000
4000461955	32897	1,600	3/16/2022	3/24/2022	8	0.000%	0.0000
4000461933	141826	18,620	3/16/2022	3/24/2022	8	0.005%	0.0004
4000461937	143727	58,169	3/16/2022	3/24/2022	8	0.015%	0.0012
4000461972	123377	6,323	3/17/2022	3/25/2022	8	0.002%	0.0001
4000461980	142942	465	3/17/2022	3/25/2022	8	0.000%	0.0000
4000461983	143477	2,765	3/17/2022	3/25/2022	8	0.001%	0.0001
4000462091	24385	3,107	3/21/2022	3/29/2022	8	0.001%	0.0001
4000462097	26207	15,650	3/21/2022	3/29/2022	8	0.004%	0.0003
4000462108	26655	1,977	3/21/2022	3/29/2022	8	0.001%	0.0000
4000462110	26674	1,680	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462057	27094	573	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462065	116384	363	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462066	118807	702	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462069	126481	8,500	3/21/2022	3/29/2022	8	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462073	132914	11,530,039	3/21/2022	3/29/2022	8	3.041%	0.2433
4000462075	138862	796	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462076	139128	727	3/21/2022	3/29/2022	8	0.000%	0.0000
4000462078	142282	25,000	3/21/2022	3/29/2022	8	0.007%	0.0005
4000462080	143659	6,800	3/21/2022	3/29/2022	8	0.002%	0.0001
4000462083	144986	4,000	3/21/2022	3/29/2022	8	0.001%	0.0001
4000462056	102060	5,000	3/21/2022	3/29/2022	8	0.001%	0.0001
4000462132	13534	66,921	3/22/2022	3/30/2022	8	0.018%	0.0014
4000462136	105195	3,314	3/22/2022	3/30/2022	8	0.001%	0.0001
4000462116	4502	2,508	3/22/2022	3/30/2022	8	0.001%	0.0001
4000462162	30475	75,242	3/23/2022	3/31/2022	8	0.020%	0.0016
4000462163	30475	47,862	3/23/2022	3/31/2022	8	0.013%	0.0010
4000462164	30475	71,187	3/23/2022	3/31/2022	8	0.019%	0.0015
4000462144	108289	264	3/23/2022	3/31/2022	8	0.000%	0.0000
4000462149	135057	2,837	3/23/2022	3/31/2022	8	0.001%	0.0001
4000462150	140752	1,228	3/23/2022	3/31/2022	8	0.000%	0.0000
4000462139	104031	1,000	3/23/2022	3/31/2022	8	0.000%	0.0000
4000462189	26639	5,940	3/24/2022	4/1/2022	8	0.002%	0.0001
4000462195	124943	5,320	3/24/2022	4/1/2022	8	0.001%	0.0001
4000462171	112215	3,706	3/24/2022	4/1/2022	8	0.001%	0.0001
4000462177	130162	1,661	3/24/2022	4/1/2022	8	0.000%	0.0000
4000462267	26338	2,389	3/28/2022	4/5/2022	8	0.001%	0.0001
4000462270	26659	101,045	3/28/2022	4/5/2022	8	0.027%	0.0021
4000462244	103392	56	3/28/2022	4/5/2022	8	0.000%	0.0000
4000462247	116384	15	3/28/2022	4/5/2022	8	0.000%	0.0000
4000462248	117154	700	3/28/2022	4/5/2022	8	0.000%	0.0000
4000462249	118807	761	3/28/2022	4/5/2022	8	0.000%	0.0000
4000462250	125742	3,750	3/28/2022	4/5/2022	8	0.001%	0.0001
4000462255	144530	11,015	3/28/2022	4/5/2022	8	0.003%	0.0002
4000462300	11305	925	3/29/2022	4/6/2022	8	0.000%	0.0000
4000462308	26490	887	3/29/2022	4/6/2022	8	0.000%	0.0000
4000462313	27994	5,830	3/29/2022	4/6/2022	8	0.002%	0.0001
4000462287	103392	381	3/29/2022	4/6/2022	8	0.000%	0.0000
4000462292	125742	3,140	3/29/2022	4/6/2022	8	0.001%	0.0001
4000462295	143154	5,220	3/29/2022	4/6/2022	8	0.001%	0.0001
4000462378	8392	20,916	3/30/2022	4/7/2022	8	0.006%	0.0004
4000462383	25708	2,417	3/30/2022	4/7/2022	8	0.001%	0.0001
4000462386	26323	591	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462387	26356	1,414	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462388	27013	2,739	3/30/2022	4/7/2022	8	0.001%	0.0001
4000462393	28737	1,100	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462398	32537	6,270	3/30/2022	4/7/2022	8	0.002%	0.0001
4000462320	4502	19,796	3/30/2022	4/7/2022	8	0.005%	0.0004
4000462321	13672	1,963	3/30/2022	4/7/2022	8	0.001%	0.0000
4000462337	116384	91	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462342	119912	1,500	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462348	130257	3,000	3/30/2022	4/7/2022	8	0.001%	0.0001
4000462356	138494	707	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462357	140752	5,379	3/30/2022	4/7/2022	8	0.001%	0.0001
4000462359	142635	15,295	3/30/2022	4/7/2022	8	0.004%	0.0003
4000462369	143991	13,118	3/30/2022	4/7/2022	8	0.003%	0.0003
4000462372	144791	800	3/30/2022	4/7/2022	8	0.000%	0.0000
4000462443	26362	4,000	3/31/2022	4/8/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462444	26382	4,807	3/31/2022	4/8/2022	8	0.001%	0.0001
4000462446	26588	25,390	3/31/2022	4/8/2022	8	0.007%	0.0005
4000462453	27962	10,311	3/31/2022	4/8/2022	8	0.003%	0.0002
4000462458	32510	3,624	3/31/2022	4/8/2022	8	0.001%	0.0001
4000462462	34064	251,311	3/31/2022	4/8/2022	8	0.066%	0.0053
4000462410	27466	4,179	3/31/2022	4/8/2022	8	0.001%	0.0001
4000462416	125742	28,353	3/31/2022	4/8/2022	8	0.007%	0.0006
4000462419	138494	3,080	3/31/2022	4/8/2022	8	0.001%	0.0001
4000462589	24281	2,320	4/4/2022	4/12/2022	8	0.001%	0.0000
4000462548	25093	114	4/4/2022	4/12/2022	8	0.000%	0.0000
4000462549	27094	5,558	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462551	103392	1,532	4/4/2022	4/12/2022	8	0.000%	0.0000
4000462552	116850	431	4/4/2022	4/12/2022	8	0.000%	0.0000
4000462555	131647	2,338	4/4/2022	4/12/2022	8	0.001%	0.0000
4000462556	132202	11,079	4/4/2022	4/12/2022	8	0.003%	0.0002
4000462557	134906	3,900	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462561	141370	13,250	4/4/2022	4/12/2022	8	0.003%	0.0003
4000462562	141822	8,319	4/4/2022	4/12/2022	8	0.002%	0.0002
4000462566	142162	11,000	4/4/2022	4/12/2022	8	0.003%	0.0002
4000462571	143270	4,500	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462572	143364	12,300	4/4/2022	4/12/2022	8	0.003%	0.0003
4000462574	143588	882	4/4/2022	4/12/2022	8	0.000%	0.0000
4000462575	143637	3,750	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462578	144015	10,000	4/4/2022	4/12/2022	8	0.003%	0.0002
4000462581	144510	2,000	4/4/2022	4/12/2022	8	0.001%	0.0000
4000462582	144567	4,000	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462583	144573	4,000	4/4/2022	4/12/2022	8	0.001%	0.0001
4000462587	144972	8,655	4/4/2022	4/12/2022	8	0.002%	0.0002
4000462598	103008	388	4/5/2022	4/13/2022	8	0.000%	0.0000
4000462605	139733	315	4/5/2022	4/13/2022	8	0.000%	0.0000
4000462606	141025	18,000	4/5/2022	4/13/2022	8	0.005%	0.0004
4000462613	144986	4,000	4/5/2022	4/13/2022	8	0.001%	0.0001
4000462639	30475	58,281	4/6/2022	4/14/2022	8	0.015%	0.0012
4000462641	33924	1,557	4/6/2022	4/14/2022	8	0.000%	0.0000
4000462620	113563	10,748	4/6/2022	4/14/2022	8	0.003%	0.0002
4000462623	125742	6,541	4/6/2022	4/14/2022	8	0.002%	0.0001
4000462624	128478	1,088	4/6/2022	4/14/2022	8	0.000%	0.0000
4000462684	34341	6,600	4/7/2022	4/15/2022	8	0.002%	0.0001
4000462647	24856	580	4/7/2022	4/15/2022	8	0.000%	0.0000
4000462651	116384	4	4/7/2022	4/15/2022	8	0.000%	0.0000
4000462653	116902	4,400	4/7/2022	4/15/2022	8	0.001%	0.0001
4000462655	125742	150	4/7/2022	4/15/2022	8	0.000%	0.0000
4000462658	138494	18,480	4/7/2022	4/15/2022	8	0.005%	0.0004
4000462664	143577	3,355	4/7/2022	4/15/2022	8	0.001%	0.0001
4000462669	144803	42,712	4/7/2022	4/15/2022	8	0.011%	0.0009
4000462770	25905	4,600	4/11/2022	4/19/2022	8	0.001%	0.0001
4000462772	26659	2,618	4/11/2022	4/19/2022	8	0.001%	0.0001
4000462775	28474	4,258	4/11/2022	4/19/2022	8	0.001%	0.0001
4000462778	34658	2,000	4/11/2022	4/19/2022	8	0.001%	0.0000
4000462748	104509	4,591	4/11/2022	4/19/2022	8	0.001%	0.0001
4000462751	116384	6,685	4/11/2022	4/19/2022	8	0.002%	0.0001
4000462758	144955	373	4/11/2022	4/19/2022	8	0.000%	0.0000
4000462794	26213	874	4/12/2022	4/20/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462781	103008	159	4/12/2022	4/20/2022	8	0.000%	0.0000
4000462782	103867	7	4/12/2022	4/20/2022	8	0.000%	0.0000
4000462787	143941	12,276	4/12/2022	4/20/2022	8	0.003%	0.0003
4000462854	27962	1,026	4/13/2022	4/21/2022	8	0.000%	0.0000
4000462856	32808	990	4/13/2022	4/21/2022	8	0.000%	0.0000
4000462863	134272	7,446	4/13/2022	4/21/2022	8	0.002%	0.0002
4000462832	138363	500	4/13/2022	4/21/2022	8	0.000%	0.0000
4000462834	141583	610	4/13/2022	4/21/2022	8	0.000%	0.0000
4000462845	145004	10,000	4/13/2022	4/21/2022	8	0.003%	0.0002
4000462846	145021	500	4/13/2022	4/21/2022	8	0.000%	0.0000
4000462900	24825	10,519	4/14/2022	4/22/2022	8	0.003%	0.0002
4000462904	25667	4,400	4/14/2022	4/22/2022	8	0.001%	0.0001
4000462905	25808	2,280	4/14/2022	4/22/2022	8	0.001%	0.0000
4000462910	26659	686	4/14/2022	4/22/2022	8	0.000%	0.0000
4000462928	34658	2,000	4/14/2022	4/22/2022	8	0.001%	0.0000
4000462866	4765	6,000	4/14/2022	4/22/2022	8	0.002%	0.0001
4000462867	15871	15,082	4/14/2022	4/22/2022	8	0.004%	0.0003
4000462879	143312	27,563	4/14/2022	4/22/2022	8	0.007%	0.0006
4000462963	34658	2,000	4/18/2022	4/26/2022	8	0.001%	0.0000
4000462937	30580	3,983	4/18/2022	4/26/2022	8	0.001%	0.0001
4000462938	116384	940	4/18/2022	4/26/2022	8	0.000%	0.0000
4000462939	118807	2,458	4/18/2022	4/26/2022	8	0.001%	0.0001
4000462941	126476	2,465,825	4/18/2022	4/26/2022	8	0.650%	0.0520
4000462945	141826	18,620	4/18/2022	4/26/2022	8	0.005%	0.0004
4000462946	142942	4,665	4/18/2022	4/26/2022	8	0.001%	0.0001
4000462947	143659	8,602	4/18/2022	4/26/2022	8	0.002%	0.0002
4000462949	144530	10,305	4/18/2022	4/26/2022	8	0.003%	0.0002
4000462950	144567	2,000	4/18/2022	4/26/2022	8	0.001%	0.0000
4000462951	144949	1,079	4/18/2022	4/26/2022	8	0.000%	0.0000
4000462979	24383	7,748	4/19/2022	4/27/2022	8	0.002%	0.0002
4000462980	25599	501	4/19/2022	4/27/2022	8	0.000%	0.0000
4000462982	26213	644	4/19/2022	4/27/2022	8	0.000%	0.0000
4000462984	27013	3,453	4/19/2022	4/27/2022	8	0.001%	0.0001
4000462985	27068	31,863	4/19/2022	4/27/2022	8	0.008%	0.0007
4000462968	103392	34	4/19/2022	4/27/2022	8	0.000%	0.0000
4000462969	116902	15,900	4/19/2022	4/27/2022	8	0.004%	0.0003
4000462970	116902	22,065	4/19/2022	4/27/2022	8	0.006%	0.0005
4000463011	144567	47,347	4/20/2022	4/28/2022	8	0.012%	0.0010
4000463012	144741	3,232	4/20/2022	4/28/2022	8	0.001%	0.0001
4000463013	144955	283	4/20/2022	4/28/2022	8	0.000%	0.0000
4000463056	26338	259	4/21/2022	4/29/2022	8	0.000%	0.0000
4000463061	26490	2,977	4/21/2022	4/29/2022	8	0.001%	0.0001
4000463065	26643	6,482	4/21/2022	4/29/2022	8	0.002%	0.0001
4000463069	27013	3,385	4/21/2022	4/29/2022	8	0.001%	0.0001
4000463071	30475	21,055	4/21/2022	4/29/2022	8	0.006%	0.0004
4000463030	15871	480	4/21/2022	4/29/2022	8	0.000%	0.0000
4000463037	126928	134	4/21/2022	4/29/2022	8	0.000%	0.0000
4000463045	144084	1,875	4/21/2022	4/29/2022	8	0.000%	0.0000
4000463029	116697	10,000	4/21/2022	4/29/2022	8	0.003%	0.0002
4000463171	11577	788	4/25/2022	5/3/2022	8	0.000%	0.0000
4000463175	27013	1,350	4/25/2022	5/3/2022	8	0.000%	0.0000
4000463147	100521	6,688	4/25/2022	5/3/2022	8	0.002%	0.0001
4000463149	103392	353	4/25/2022	5/3/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463151	116332	114,263	4/25/2022	5/3/2022	8	0.030%	0.0024
4000463154	133825	3,500	4/25/2022	5/3/2022	8	0.001%	0.0001
4000463160	143340	3,884	4/25/2022	5/3/2022	8	0.001%	0.0001
4000463161	143463	18,500	4/25/2022	5/3/2022	8	0.005%	0.0004
4000463164	143768	1,000	4/25/2022	5/3/2022	8	0.000%	0.0000
4000463165	144291	1,000	4/25/2022	5/3/2022	8	0.000%	0.0000
4000463166	144567	2,000	4/25/2022	5/3/2022	8	0.001%	0.0000
4000463167	144949	147	4/25/2022	5/3/2022	8	0.000%	0.0000
4000463196	26453	1,210	4/26/2022	5/4/2022	8	0.000%	0.0000
4000463199	27068	14,136	4/26/2022	5/4/2022	8	0.004%	0.0003
4000463201	34088	1,459	4/26/2022	5/4/2022	8	0.000%	0.0000
4000463186	133926	8,806	4/26/2022	5/4/2022	8	0.002%	0.0002
4000463191	145083	5,775	4/26/2022	5/4/2022	8	0.002%	0.0001
4000463231	11372	3,428	4/27/2022	5/5/2022	8	0.001%	0.0001
4000463236	25599	2,019	4/27/2022	5/5/2022	8	0.001%	0.0000
4000463237	25659	463	4/27/2022	5/5/2022	8	0.000%	0.0000
4000463245	26674	1,330	4/27/2022	5/5/2022	8	0.000%	0.0000
4000463246	26679	15,250	4/27/2022	5/5/2022	8	0.004%	0.0003
4000463247	27013	11,145	4/27/2022	5/5/2022	8	0.003%	0.0002
4000463251	32356	1,633	4/27/2022	5/5/2022	8	0.000%	0.0000
4000463208	4502	5,108	4/27/2022	5/5/2022	8	0.001%	0.0001
4000463213	33624	4,048	4/27/2022	5/5/2022	8	0.001%	0.0001
4000463225	143340	315,126	4/27/2022	5/5/2022	8	0.083%	0.0066
4000463300	24825	9,163	4/28/2022	5/6/2022	8	0.002%	0.0002
4000463303	25905	3,800	4/28/2022	5/6/2022	8	0.001%	0.0001
4000463306	26323	1,559	4/28/2022	5/6/2022	8	0.000%	0.0000
4000463315	27013	48,964	4/28/2022	5/6/2022	8	0.013%	0.0010
4000463269	103990	94	4/28/2022	5/6/2022	8	0.000%	0.0000
4000463283	143577	9,871	4/28/2022	5/6/2022	8	0.003%	0.0002
4000463424	24113	7,448	5/2/2022	5/10/2022	8	0.002%	0.0002
4000463431	26363	1,227	5/2/2022	5/10/2022	8	0.000%	0.0000
4000463432	26588	13,535	5/2/2022	5/10/2022	8	0.004%	0.0003
4000463441	117331	91,253	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463442	117331	91,263	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463443	117331	91,651	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463444	117331	92,632	5/2/2022	5/10/2022	8	0.024%	0.0020
4000463445	117331	94,775	5/2/2022	5/10/2022	8	0.025%	0.0020
4000463446	117331	89,136	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463447	117331	89,951	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463448	117331	90,300	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463449	117331	91,037	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463450	117331	91,144	5/2/2022	5/10/2022	8	0.024%	0.0019
4000463406	4502	10,479	5/2/2022	5/10/2022	8	0.003%	0.0002
4000463409	111669	554	5/2/2022	5/10/2022	8	0.000%	0.0000
4000463412	116384	115	5/2/2022	5/10/2022	8	0.000%	0.0000
4000463414	118807	696	5/2/2022	5/10/2022	8	0.000%	0.0000
4000463507	24113	470	5/3/2022	5/11/2022	8	0.000%	0.0000
4000463508	24281	8,232	5/3/2022	5/11/2022	8	0.002%	0.0002
4000463512	27013	1,589	5/3/2022	5/11/2022	8	0.000%	0.0000
4000463456	103392	1,323	5/3/2022	5/11/2022	8	0.000%	0.0000
4000463462	125536	84	5/3/2022	5/11/2022	8	0.000%	0.0000
4000463469	136045	42,000	5/3/2022	5/11/2022	8	0.011%	0.0009
4000463473	141025	18,000	5/3/2022	5/11/2022	8	0.005%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463474	141370	13,250	5/3/2022	5/11/2022	8	0.003%	0.0003
4000463480	142607	2,500	5/3/2022	5/11/2022	8	0.001%	0.0001
4000463481	142787	10,258	5/3/2022	5/11/2022	8	0.003%	0.0002
4000463485	143364	12,300	5/3/2022	5/11/2022	8	0.003%	0.0003
4000463493	144410	2,850	5/3/2022	5/11/2022	8	0.001%	0.0001
4000463499	144986	4,000	5/3/2022	5/11/2022	8	0.001%	0.0001
4000463501	145028	15,000	5/3/2022	5/11/2022	8	0.004%	0.0003
4000463502	145067	2,200	5/3/2022	5/11/2022	8	0.001%	0.0000
4000463453	129764	5,000	5/3/2022	5/11/2022	8	0.001%	0.0001
4000463532	11372	589	5/4/2022	5/12/2022	8	0.000%	0.0000
4000463521	125742	2,563	5/4/2022	5/12/2022	8	0.001%	0.0001
4000463543	109293	21,648	5/5/2022	5/13/2022	8	0.006%	0.0005
4000463637	18267	3,969	5/9/2022	5/17/2022	8	0.001%	0.0001
4000463644	28474	2,244	5/9/2022	5/17/2022	8	0.001%	0.0000
4000463627	4502	10,095	5/9/2022	5/17/2022	8	0.003%	0.0002
4000463629	103392	330	5/9/2022	5/17/2022	8	0.000%	0.0000
4000463630	105195	12,989	5/9/2022	5/17/2022	8	0.003%	0.0003
4000463631	115998	400	5/9/2022	5/17/2022	8	0.000%	0.0000
4000463632	118807	1,163	5/9/2022	5/17/2022	8	0.000%	0.0000
4000463669	24113	11,548	5/10/2022	5/18/2022	8	0.003%	0.0002
4000463673	26490	914	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463675	26639	270	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463676	26655	3,146	5/10/2022	5/18/2022	8	0.001%	0.0001
4000463677	27013	6,784	5/10/2022	5/18/2022	8	0.002%	0.0001
4000463678	28084	1,188	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463680	32875	3,300	5/10/2022	5/18/2022	8	0.001%	0.0001
4000463681	33747	1,407	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463683	34341	15,400	5/10/2022	5/18/2022	8	0.004%	0.0003
4000463646	6396	2,975	5/10/2022	5/18/2022	8	0.001%	0.0001
4000463656	126775	502	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463659	139733	622	5/10/2022	5/18/2022	8	0.000%	0.0000
4000463664	145034	11,306	5/10/2022	5/18/2022	8	0.003%	0.0002
4000463718	25808	960	5/11/2022	5/19/2022	8	0.000%	0.0000
4000463723	26679	2,750	5/11/2022	5/19/2022	8	0.001%	0.0001
4000463724	29334	2,250	5/11/2022	5/19/2022	8	0.001%	0.0000
4000463689	26604	5,150	5/11/2022	5/19/2022	8	0.001%	0.0001
4000463693	108149	54	5/11/2022	5/19/2022	8	0.000%	0.0000
4000463698	133926	20,074	5/11/2022	5/19/2022	8	0.005%	0.0004
4000463709	145115	4,268	5/11/2022	5/19/2022	8	0.001%	0.0001
4000463750	30475	30,475	5/12/2022	5/20/2022	8	0.008%	0.0006
4000463753	34658	2,025	5/12/2022	5/20/2022	8	0.001%	0.0000
4000463880	10384	7,200	5/16/2022	5/24/2022	8	0.002%	0.0002
4000463886	24825	1,208	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463901	105195	36,416	5/16/2022	5/24/2022	8	0.010%	0.0008
4000463902	117331	4,950	5/16/2022	5/24/2022	8	0.001%	0.0001
4000463904	126775	65,405	5/16/2022	5/24/2022	8	0.017%	0.0014
4000463823	4502	4,099	5/16/2022	5/24/2022	8	0.001%	0.0001
4000463827	26588	1,680	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463830	104154	86	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463832	105195	6,087	5/16/2022	5/24/2022	8	0.002%	0.0001
4000463833	107794	69	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463836	115563	1,400	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463852	126775	10,250	5/16/2022	5/24/2022	8	0.003%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463854	127074	300	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463868	142942	4,312	5/16/2022	5/24/2022	8	0.001%	0.0001
4000463870	144097	5,466,807	5/16/2022	5/24/2022	8	1.442%	0.1154
4000463871	144270	655	5/16/2022	5/24/2022	8	0.000%	0.0000
4000463872	144532	3,000	5/16/2022	5/24/2022	8	0.001%	0.0001
4000463922	28084	760	5/17/2022	5/25/2022	8	0.000%	0.0000
4000463923	32853	2,565	5/17/2022	5/25/2022	8	0.001%	0.0001
4000463907	103392	16	5/17/2022	5/25/2022	8	0.000%	0.0000
4000463915	141826	18,620	5/17/2022	5/25/2022	8	0.005%	0.0004
4000463917	144270	42	5/17/2022	5/25/2022	8	0.000%	0.0000
4000463953	25131	2,090	5/18/2022	5/26/2022	8	0.001%	0.0000
4000463954	25659	10,670	5/18/2022	5/26/2022	8	0.003%	0.0002
4000463959	26679	625	5/18/2022	5/26/2022	8	0.000%	0.0000
4000463963	28737	8,150	5/18/2022	5/26/2022	8	0.002%	0.0002
4000463964	30068	325	5/18/2022	5/26/2022	8	0.000%	0.0000
4000463965	30475	48,463	5/18/2022	5/26/2022	8	0.013%	0.0010
4000463967	32808	1,870	5/18/2022	5/26/2022	8	0.000%	0.0000
4000463931	103695	594	5/18/2022	5/26/2022	8	0.000%	0.0000
4000463999	13911	49,998	5/19/2022	5/27/2022	8	0.013%	0.0011
4000464005	27068	912	5/19/2022	5/27/2022	8	0.000%	0.0000
4000463978	13911	3,860	5/19/2022	5/27/2022	8	0.001%	0.0001
4000463979	15871	642	5/19/2022	5/27/2022	8	0.000%	0.0000
4000463981	34888	58	5/19/2022	5/27/2022	8	0.000%	0.0000
4000463984	105195	2,262	5/19/2022	5/27/2022	8	0.001%	0.0000
4000463993	143941	11,890	5/19/2022	5/27/2022	8	0.003%	0.0003
4000464113	18267	5,501	5/24/2022	6/1/2022	8	0.001%	0.0001
4000464114	25083	1,448	5/24/2022	6/1/2022	8	0.000%	0.0000
4000464129	33238	840	5/24/2022	6/1/2022	8	0.000%	0.0000
4000464098	105195	982	5/24/2022	6/1/2022	8	0.000%	0.0000
4000464101	116332	66,458	5/24/2022	6/1/2022	8	0.018%	0.0014
4000464102	116384	58	5/24/2022	6/1/2022	8	0.000%	0.0000
4000464106	143659	6,800	5/24/2022	6/1/2022	8	0.002%	0.0001
4000464107	143659	51,043	5/24/2022	6/1/2022	8	0.013%	0.0011
4000464159	10384	3,000	5/25/2022	6/2/2022	8	0.001%	0.0001
4000464163	24383	17,860	5/25/2022	6/2/2022	8	0.005%	0.0004
4000464164	24383	18,018	5/25/2022	6/2/2022	8	0.005%	0.0004
4000464165	25659	13,220	5/25/2022	6/2/2022	8	0.003%	0.0003
4000464172	27013	4,765	5/25/2022	6/2/2022	8	0.001%	0.0001
4000464173	28084	12,635	5/25/2022	6/2/2022	8	0.003%	0.0003
4000464135	4765	16,992	5/25/2022	6/2/2022	8	0.004%	0.0004
4000464148	139713	77,190	5/25/2022	6/2/2022	8	0.020%	0.0016
4000464153	144097	6,126,174	5/25/2022	6/2/2022	8	1.616%	0.1293
4000464155	144530	8,195	5/25/2022	6/2/2022	8	0.002%	0.0002
4000464156	144878	9,716	5/25/2022	6/2/2022	8	0.003%	0.0002
4000464218	26604	655	5/26/2022	6/3/2022	8	0.000%	0.0000
4000464219	26659	31,105	5/26/2022	6/3/2022	8	0.008%	0.0007
4000464231	32537	3,300	5/26/2022	6/3/2022	8	0.001%	0.0001
4000464236	130375	14,431	5/26/2022	6/3/2022	8	0.004%	0.0003
4000464182	15871	980	5/26/2022	6/3/2022	8	0.000%	0.0000
4000464185	116332	1,113	5/26/2022	6/3/2022	8	0.000%	0.0000
4000464200	144097	1,001,113	5/26/2022	6/3/2022	8	0.264%	0.0211
4000464201	144270	38,900	5/26/2022	6/3/2022	8	0.010%	0.0008
4000464202	144567	1,178	5/26/2022	6/3/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464204	144955	1,663	5/26/2022	6/3/2022	8	0.000%	0.0000
4000464344	11260	3,236	5/31/2022	6/8/2022	8	0.001%	0.0001
4000464351	26297	1,369	5/31/2022	6/8/2022	8	0.000%	0.0000
4000464357	26588	22,125	5/31/2022	6/8/2022	8	0.006%	0.0005
4000464359	26639	21,263	5/31/2022	6/8/2022	8	0.006%	0.0004
4000464366	32245	7,894	5/31/2022	6/8/2022	8	0.002%	0.0002
4000464314	103392	15	5/31/2022	6/8/2022	8	0.000%	0.0000
4000464319	111078	1,400	5/31/2022	6/8/2022	8	0.000%	0.0000
4000464321	113967	4,200	5/31/2022	6/8/2022	8	0.001%	0.0001
4000464326	126797	750	5/31/2022	6/8/2022	8	0.000%	0.0000
4000464328	130634	40,770	5/31/2022	6/8/2022	8	0.011%	0.0009
4000464331	138361	1,500	5/31/2022	6/8/2022	8	0.000%	0.0000
4000464340	145167	2,500	5/31/2022	6/8/2022	8	0.001%	0.0001
4000464392	8998	7,473	6/1/2022	6/9/2022	8	0.002%	0.0002
4000464397	24259	18,501	6/1/2022	6/9/2022	8	0.005%	0.0004
4000464409	27962	456	6/1/2022	6/9/2022	8	0.000%	0.0000
4000464411	32808	2,310	6/1/2022	6/9/2022	8	0.001%	0.0000
4000464381	139487	574	6/1/2022	6/9/2022	8	0.000%	0.0000
4000464385	144791	1,600	6/1/2022	6/9/2022	8	0.000%	0.0000
4000464386	144878	3,211	6/1/2022	6/9/2022	8	0.001%	0.0001
4000464388	144955	2,110	6/1/2022	6/9/2022	8	0.001%	0.0000
4000464370	101122	1,500	6/1/2022	6/9/2022	8	0.000%	0.0000
4000464474	26356	1,150	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464480	34064	280	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464419	27094	9,328	6/2/2022	6/10/2022	8	0.002%	0.0002
4000464420	102558	53,823	6/2/2022	6/10/2022	8	0.014%	0.0011
4000464422	105195	1,996	6/2/2022	6/10/2022	8	0.001%	0.0000
4000464424	112215	2,320	6/2/2022	6/10/2022	8	0.001%	0.0000
4000464425	116384	117	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464427	118807	212	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464436	139982	9,422	6/2/2022	6/10/2022	8	0.002%	0.0002
4000464439	141370	13,250	6/2/2022	6/10/2022	8	0.003%	0.0003
4000464446	142787	10,258	6/2/2022	6/10/2022	8	0.003%	0.0002
4000464449	143270	4,500	6/2/2022	6/10/2022	8	0.001%	0.0001
4000464454	143577	10,533	6/2/2022	6/10/2022	8	0.003%	0.0002
4000464465	144927	6,000	6/2/2022	6/10/2022	8	0.002%	0.0001
4000464466	144949	355	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464467	144955	969	6/2/2022	6/10/2022	8	0.000%	0.0000
4000464468	144972	8,655	6/2/2022	6/10/2022	8	0.002%	0.0002
4000464559	24385	2,780	6/6/2022	6/14/2022	8	0.001%	0.0001
4000464563	26207	16,825	6/6/2022	6/14/2022	8	0.004%	0.0004
4000464573	124943	1,900	6/6/2022	6/14/2022	8	0.001%	0.0000
4000464546	103392	231	6/6/2022	6/14/2022	8	0.000%	0.0000
4000464549	132094	248	6/6/2022	6/14/2022	8	0.000%	0.0000
4000464550	141230	17,000	6/6/2022	6/14/2022	8	0.004%	0.0004
4000464594	24383	680	6/7/2022	6/15/2022	8	0.000%	0.0000
4000464596	25659	3,850	6/7/2022	6/15/2022	8	0.001%	0.0001
4000464597	27013	169	6/7/2022	6/15/2022	8	0.000%	0.0000
4000464600	27982	1,856	6/7/2022	6/15/2022	8	0.000%	0.0000
4000464601	28084	1,330	6/7/2022	6/15/2022	8	0.000%	0.0000
4000464605	32537	715	6/7/2022	6/15/2022	8	0.000%	0.0000
4000464636	23681	3,184	6/8/2022	6/16/2022	8	0.001%	0.0001
4000464638	27389	24,553	6/8/2022	6/16/2022	8	0.006%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464639	33770	2,508	6/8/2022	6/16/2022	8	0.001%	0.0001
4000464611	4502	18,863	6/8/2022	6/16/2022	8	0.005%	0.0004
4000464616	103404	58	6/8/2022	6/16/2022	8	0.000%	0.0000
4000464622	126791	11,000	6/8/2022	6/16/2022	8	0.003%	0.0002
4000464629	143426	492,657	6/8/2022	6/16/2022	8	0.130%	0.0104
4000464633	144955	106	6/8/2022	6/16/2022	8	0.000%	0.0000
4000464669	26659	997	6/9/2022	6/17/2022	8	0.000%	0.0000
4000464674	34393	4,800	6/9/2022	6/17/2022	8	0.001%	0.0001
4000464651	121825	5,999	6/9/2022	6/17/2022	8	0.002%	0.0001
4000464652	125742	250	6/9/2022	6/17/2022	8	0.000%	0.0000
4000464661	144663	142,531	6/9/2022	6/17/2022	8	0.038%	0.0030
4000464809	14060	1,923	6/14/2022	6/22/2022	8	0.001%	0.0000
4000464787	4502	33	6/14/2022	6/22/2022	8	0.000%	0.0000
4000464792	115761	47	6/14/2022	6/22/2022	8	0.000%	0.0000
4000464803	143312	64,829	6/14/2022	6/22/2022	8	0.017%	0.0014
4000464804	143659	2,871	6/14/2022	6/22/2022	8	0.001%	0.0001
4000464845	11577	630	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464848	26356	5,449	6/15/2022	6/23/2022	8	0.001%	0.0001
4000464854	28084	1,472	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464856	30475	53,898	6/15/2022	6/23/2022	8	0.014%	0.0011
4000464857	30475	42,154	6/15/2022	6/23/2022	8	0.011%	0.0009
4000464825	111669	40	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464827	116384	1,145	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464828	117204	2,500	6/15/2022	6/23/2022	8	0.001%	0.0001
4000464831	125960	87	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464832	129783	159	6/15/2022	6/23/2022	8	0.000%	0.0000
4000464891	27013	4,045	6/16/2022	6/24/2022	8	0.001%	0.0001
4000464892	27994	8,030	6/16/2022	6/24/2022	8	0.002%	0.0002
4000464874	138494	3,850	6/16/2022	6/24/2022	8	0.001%	0.0001
4000464882	143577	5,704	6/16/2022	6/24/2022	8	0.002%	0.0001
4000464885	144898	19,404	6/16/2022	6/24/2022	8	0.005%	0.0004
4000464983	116384	51	6/20/2022	6/28/2022	8	0.000%	0.0000
4000465012	24113	380	6/21/2022	6/29/2022	8	0.000%	0.0000
4000465014	24825	510	6/21/2022	6/29/2022	8	0.000%	0.0000
4000465018	27994	1,100	6/21/2022	6/29/2022	8	0.000%	0.0000
4000465002	103392	54	6/21/2022	6/29/2022	8	0.000%	0.0000
4000465005	103867	7	6/21/2022	6/29/2022	8	0.000%	0.0000
4000465039	25908	4,375	6/22/2022	6/30/2022	8	0.001%	0.0001
4000465042	26644	2,700	6/22/2022	6/30/2022	8	0.001%	0.0001
4000465043	27013	874	6/22/2022	6/30/2022	8	0.000%	0.0000
4000465044	27389	1,840	6/22/2022	6/30/2022	8	0.000%	0.0000
4000465048	32099	980	6/22/2022	6/30/2022	8	0.000%	0.0000
4000465054	106699	6,863	6/22/2022	6/30/2022	8	0.002%	0.0001
4000465034	144955	5,667	6/22/2022	6/30/2022	8	0.001%	0.0001
4000465019	115795	1,000	6/22/2022	6/30/2022	8	0.000%	0.0000
4000465089	24765	2,466	6/23/2022	7/1/2022	8	0.001%	0.0001
4000465095	26604	43,735	6/23/2022	7/1/2022	8	0.012%	0.0009
4000465097	27068	3,876	6/23/2022	7/1/2022	8	0.001%	0.0001
4000465099	30475	16,597	6/23/2022	7/1/2022	8	0.004%	0.0004
4000465100	33956	9,586	6/23/2022	7/1/2022	8	0.003%	0.0002
4000465103	106699	5,354	6/23/2022	7/1/2022	8	0.001%	0.0001
4000465104	117331	33,200	6/23/2022	7/1/2022	8	0.009%	0.0007
4000465063	103114	29	6/23/2022	7/1/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465075	141086	11,000	6/23/2022	7/1/2022	8	0.003%	0.0002
4000465077	143072	2,096	6/23/2022	7/1/2022	8	0.001%	0.0000
4000465084	144955	1,164	6/23/2022	7/1/2022	8	0.000%	0.0000
4000465188	125742	199	6/27/2022	7/5/2022	8	0.000%	0.0000
4000465257	14060	5,645	6/28/2022	7/6/2022	8	0.001%	0.0001
4000465269	34341	1,675	6/28/2022	7/6/2022	8	0.000%	0.0000
4000465272	126775	1,108	6/28/2022	7/6/2022	8	0.000%	0.0000
4000465236	104154	616	6/28/2022	7/6/2022	8	0.000%	0.0000
4000465240	111770	290	6/28/2022	7/6/2022	8	0.000%	0.0000
4000465248	142635	29,192	6/28/2022	7/6/2022	8	0.008%	0.0006
4000465249	142700	3,030	6/28/2022	7/6/2022	8	0.001%	0.0001
4000465231	133368	5,000	6/28/2022	7/6/2022	8	0.001%	0.0001
4000465289	11260	4,880	6/29/2022	7/7/2022	8	0.001%	0.0001
4000465291	26016	796	6/29/2022	7/7/2022	8	0.000%	0.0000
4000465292	28737	2,900	6/29/2022	7/7/2022	8	0.001%	0.0001
4000465293	32099	2,363	6/29/2022	7/7/2022	8	0.001%	0.0000
4000465294	34341	95	6/29/2022	7/7/2022	8	0.000%	0.0000
4000465274	107047	183	6/29/2022	7/7/2022	8	0.000%	0.0000
4000465357	8392	10,776	6/30/2022	7/8/2022	8	0.003%	0.0002
4000465364	24383	4,345	6/30/2022	7/8/2022	8	0.001%	0.0001
4000465376	34937	12,000	6/30/2022	7/8/2022	8	0.003%	0.0003
4000465297	4502	10,847	6/30/2022	7/8/2022	8	0.003%	0.0002
4000465300	26958	6,083	6/30/2022	7/8/2022	8	0.002%	0.0001
4000465301	101853	4,204	6/30/2022	7/8/2022	8	0.001%	0.0001
4000465306	112103	50,618	6/30/2022	7/8/2022	8	0.013%	0.0011
4000465309	116850	431	6/30/2022	7/8/2022	8	0.000%	0.0000
4000465320	141025	18,000	6/30/2022	7/8/2022	8	0.005%	0.0004
4000465324	141831	11,647	6/30/2022	7/8/2022	8	0.003%	0.0002
4000465326	142002	7,696	6/30/2022	7/8/2022	8	0.002%	0.0002
4000465335	143364	12,300	6/30/2022	7/8/2022	8	0.003%	0.0003
4000465343	144270	107,308	6/30/2022	7/8/2022	8	0.028%	0.0023
4000465352	144955	13,833	6/30/2022	7/8/2022	8	0.004%	0.0003
4000465486	26213	506	7/5/2022	7/13/2022	8	0.000%	0.0000
4000465493	106699	17,558	7/5/2022	7/13/2022	8	0.005%	0.0004
4000465479	143852	425	7/5/2022	7/13/2022	8	0.000%	0.0000
4000465480	144986	4,000	7/5/2022	7/13/2022	8	0.001%	0.0001
4000465523	27013	19,942	7/6/2022	7/14/2022	8	0.005%	0.0004
4000465526	34531	12,481	7/6/2022	7/14/2022	8	0.003%	0.0003
4000465498	105195	1,598	7/6/2022	7/14/2022	8	0.000%	0.0000
4000465501	121825	29,997	7/6/2022	7/14/2022	8	0.008%	0.0006
4000465502	125742	12,330	7/6/2022	7/14/2022	8	0.003%	0.0003
4000465517	144270	1,141	7/6/2022	7/14/2022	8	0.000%	0.0000
4000465554	25173	6,160	7/7/2022	7/15/2022	8	0.002%	0.0001
4000465530	4502	7,601	7/7/2022	7/15/2022	8	0.002%	0.0002
4000465532	15871	490	7/7/2022	7/15/2022	8	0.000%	0.0000
4000465534	31399	40,223	7/7/2022	7/15/2022	8	0.011%	0.0008
4000465538	115761	285	7/7/2022	7/15/2022	8	0.000%	0.0000
4000465651	18267	1,444	7/11/2022	7/19/2022	8	0.000%	0.0000
4000465657	124943	1,663	7/11/2022	7/19/2022	8	0.000%	0.0000
4000465635	105195	2,433	7/11/2022	7/19/2022	8	0.001%	0.0001
4000465637	118807	1,109	7/11/2022	7/19/2022	8	0.000%	0.0000
4000465638	135194	183,053	7/11/2022	7/19/2022	8	0.048%	0.0039
4000465641	143072	7	7/11/2022	7/19/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465642	143340	21,031	7/11/2022	7/19/2022	8	0.006%	0.0004
4000465643	143741	3,950	7/11/2022	7/19/2022	8	0.001%	0.0001
4000465645	144567	5,000	7/11/2022	7/19/2022	8	0.001%	0.0001
4000465728	24383	9,270	7/12/2022	7/20/2022	8	0.002%	0.0002
4000465711	21678	29,759	7/12/2022	7/20/2022	8	0.008%	0.0006
4000465713	103114	931	7/12/2022	7/20/2022	8	0.000%	0.0000
4000465714	103620	245	7/12/2022	7/20/2022	8	0.000%	0.0000
4000465716	112215	19,140	7/12/2022	7/20/2022	8	0.005%	0.0004
4000465717	125814	31	7/12/2022	7/20/2022	8	0.000%	0.0000
4000465722	143340	64,980	7/12/2022	7/20/2022	8	0.017%	0.0014
4000465761	24259	514	7/13/2022	7/21/2022	8	0.000%	0.0000
4000465762	26453	4,540	7/13/2022	7/21/2022	8	0.001%	0.0001
4000465767	34064	18	7/13/2022	7/21/2022	8	0.000%	0.0000
4000465772	117331	69,150	7/13/2022	7/21/2022	8	0.018%	0.0015
4000465748	125742	7,704	7/13/2022	7/21/2022	8	0.002%	0.0002
4000465749	138494	10,440	7/13/2022	7/21/2022	8	0.003%	0.0002
4000465758	145137	850	7/13/2022	7/21/2022	8	0.000%	0.0000
4000465803	27068	5,358	7/14/2022	7/22/2022	8	0.001%	0.0001
4000465806	33203	3,853	7/14/2022	7/22/2022	8	0.001%	0.0001
4000465807	33770	43,292	7/14/2022	7/22/2022	8	0.011%	0.0009
4000465776	15871	5,316	7/14/2022	7/22/2022	8	0.001%	0.0001
4000465788	143584	106,756	7/14/2022	7/22/2022	8	0.028%	0.0023
4000465789	144270	109,514	7/14/2022	7/22/2022	8	0.029%	0.0023
4000465867	102990	1,500	7/18/2022	7/26/2022	8	0.000%	0.0000
4000465878	143622	35,033	7/18/2022	7/26/2022	8	0.009%	0.0007
4000465907	25808	21,600	7/19/2022	7/27/2022	8	0.006%	0.0005
4000465908	26604	6,415	7/19/2022	7/27/2022	8	0.002%	0.0001
4000465911	26655	1,005	7/19/2022	7/27/2022	8	0.000%	0.0000
4000465890	103392	27	7/19/2022	7/27/2022	8	0.000%	0.0000
4000465891	107182	160	7/19/2022	7/27/2022	8	0.000%	0.0000
4000465894	125742	2,241	7/19/2022	7/27/2022	8	0.001%	0.0000
4000465899	142942	16,437	7/19/2022	7/27/2022	8	0.004%	0.0003
4000465970	26453	6,690	7/20/2022	7/28/2022	8	0.002%	0.0001
4000465975	28737	1,200	7/20/2022	7/28/2022	8	0.000%	0.0000
4000465976	30475	103,882	7/20/2022	7/28/2022	8	0.027%	0.0022
4000465977	30475	89,725	7/20/2022	7/28/2022	8	0.024%	0.0019
4000465942	6396	500	7/20/2022	7/28/2022	8	0.000%	0.0000
4000465950	121853	1,965,577	7/20/2022	7/28/2022	8	0.518%	0.0415
4000465960	144270	792	7/20/2022	7/28/2022	8	0.000%	0.0000
4000465961	144281	3,000	7/20/2022	7/28/2022	8	0.001%	0.0001
4000465988	15871	4,034	7/21/2022	7/29/2022	8	0.001%	0.0001
4000465990	34888	196	7/21/2022	7/29/2022	8	0.000%	0.0000
4000465993	138494	15,725	7/21/2022	7/29/2022	8	0.004%	0.0003
4000465997	143072	16,236	7/21/2022	7/29/2022	8	0.004%	0.0003
4000465999	144270	7,180	7/21/2022	7/29/2022	8	0.002%	0.0002
4000465985	145236	3,510	7/21/2022	7/29/2022	8	0.001%	0.0001
4000466106	34064	246	7/25/2022	8/2/2022	8	0.000%	0.0000
4000466087	103392	52	7/25/2022	8/2/2022	8	0.000%	0.0000
4000466089	119251	28,838	7/25/2022	8/2/2022	8	0.008%	0.0006
4000466091	135194	20,304	7/25/2022	8/2/2022	8	0.005%	0.0004
4000466161	25667	5,800	7/26/2022	8/3/2022	8	0.002%	0.0001
4000466162	26604	655	7/26/2022	8/3/2022	8	0.000%	0.0000
4000466108	17667	142,900	7/26/2022	8/3/2022	8	0.038%	0.0030

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466124	141831	11,880	7/26/2022	8/3/2022	8	0.003%	0.0003
4000466126	142607	2,500	7/26/2022	8/3/2022	8	0.001%	0.0001
4000466127	142787	10,258	7/26/2022	8/3/2022	8	0.003%	0.0002
4000466132	143270	4,500	7/26/2022	8/3/2022	8	0.001%	0.0001
4000466147	144573	4,000	7/26/2022	8/3/2022	8	0.001%	0.0001
4000466151	144972	8,655	7/26/2022	8/3/2022	8	0.002%	0.0002
4000466153	145034	11,345	7/26/2022	8/3/2022	8	0.003%	0.0002
4000466188	24383	4,975	7/27/2022	8/4/2022	8	0.001%	0.0001
4000466192	26639	810	7/27/2022	8/4/2022	8	0.000%	0.0000
4000466194	30257	9,172	7/27/2022	8/4/2022	8	0.002%	0.0002
4000466195	30475	15,255	7/27/2022	8/4/2022	8	0.004%	0.0003
4000466198	117331	1,103	7/27/2022	8/4/2022	8	0.000%	0.0000
4000466171	121825	5,999	7/27/2022	8/4/2022	8	0.002%	0.0001
4000466172	125742	17,088	7/27/2022	8/4/2022	8	0.005%	0.0004
4000466174	138494	51,000	7/27/2022	8/4/2022	8	0.013%	0.0011
4000466181	144567	284	7/27/2022	8/4/2022	8	0.000%	0.0000
4000466182	144955	19,763	7/27/2022	8/4/2022	8	0.005%	0.0004
4000466232	24385	7,435	7/28/2022	8/5/2022	8	0.002%	0.0002
4000466234	26604	655	7/28/2022	8/5/2022	8	0.000%	0.0000
4000466247	34341	6,600	7/28/2022	8/5/2022	8	0.002%	0.0001
4000466210	15871	1,124	7/28/2022	8/5/2022	8	0.000%	0.0000
4000466221	139713	154,380	7/28/2022	8/5/2022	8	0.041%	0.0033
4000466225	145034	184,000	7/28/2022	8/5/2022	8	0.049%	0.0039
4000466368	10384	3,300	8/1/2022	8/9/2022	8	0.001%	0.0001
4000466370	11305	7,246	8/1/2022	8/9/2022	8	0.002%	0.0002
4000466374	18267	1,123	8/1/2022	8/9/2022	8	0.000%	0.0000
4000466348	118807	872	8/1/2022	8/9/2022	8	0.000%	0.0000
4000466354	142642	4,554	8/1/2022	8/9/2022	8	0.001%	0.0001
4000466362	145059	2,000	8/1/2022	8/9/2022	8	0.001%	0.0000
4000466395	32927	140,152	8/1/2022	8/9/2022	8	0.037%	0.0030
4000466398	32977	26,250	8/1/2022	8/9/2022	8	0.007%	0.0006
4000466399	32980	4,015	8/1/2022	8/9/2022	8	0.001%	0.0001
4000466401	32989	5,200	8/1/2022	8/9/2022	8	0.001%	0.0001
4000466403	33007	7,999	8/1/2022	8/9/2022	8	0.002%	0.0002
4000466405	33013	8,719	8/1/2022	8/9/2022	8	0.002%	0.0002
4000466407	33020	61,031	8/1/2022	8/9/2022	8	0.016%	0.0013
4000466410	33047	14,862	8/1/2022	8/9/2022	8	0.004%	0.0003
4000466412	33054	24,904	8/1/2022	8/9/2022	8	0.007%	0.0005
4000466413	33063	30,834	8/1/2022	8/9/2022	8	0.008%	0.0007
4000466419	33132	3,927	8/1/2022	8/9/2022	8	0.001%	0.0001
4000466430	9001	100,371	8/2/2022	8/10/2022	8	0.026%	0.0021
4000466434	26639	7,628	8/2/2022	8/10/2022	8	0.002%	0.0002
4000466424	103392	19	8/2/2022	8/10/2022	8	0.000%	0.0000
4000466466	25599	11,408	8/3/2022	8/11/2022	8	0.003%	0.0002
4000466467	25808	480	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466468	25908	6,125	8/3/2022	8/11/2022	8	0.002%	0.0001
4000466471	27068	1,026	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466443	103639	205	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466445	103990	97	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466454	125783	425	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466455	125960	277	8/3/2022	8/11/2022	8	0.000%	0.0000
4000466476	32933	7,544	8/3/2022	8/11/2022	8	0.002%	0.0002
4000466497	112215	812	8/4/2022	8/12/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466592	11305	3,706	8/8/2022	8/16/2022	8	0.001%	0.0001
4000466598	25083	2,838	8/8/2022	8/16/2022	8	0.001%	0.0001
4000466583	116384	58	8/8/2022	8/16/2022	8	0.000%	0.0000
4000466587	143659	15,318	8/8/2022	8/16/2022	8	0.004%	0.0003
4000466588	143741	2,900	8/8/2022	8/16/2022	8	0.001%	0.0001
4000466590	145263	50,000	8/8/2022	8/16/2022	8	0.013%	0.0011
4000466639	24383	5,025	8/9/2022	8/17/2022	8	0.001%	0.0001
4000466640	25131	380	8/9/2022	8/17/2022	8	0.000%	0.0000
4000466620	104496	81	8/9/2022	8/17/2022	8	0.000%	0.0000
4000466625	125742	5,805	8/9/2022	8/17/2022	8	0.002%	0.0001
4000466626	132321	104	8/9/2022	8/17/2022	8	0.000%	0.0000
4000466630	142942	7,463	8/9/2022	8/17/2022	8	0.002%	0.0002
4000466632	143743	24,468	8/9/2022	8/17/2022	8	0.006%	0.0005
4000466691	34348	2,325	8/10/2022	8/18/2022	8	0.001%	0.0000
4000466643	9145	5,400	8/10/2022	8/18/2022	8	0.001%	0.0001
4000466645	32842	1,663	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466648	110599	350	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466649	110933	10,000	8/10/2022	8/18/2022	8	0.003%	0.0002
4000466652	116384	4	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466657	128237	10,000	8/10/2022	8/18/2022	8	0.003%	0.0002
4000466659	129855	432	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466662	131647	935	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466671	143340	10,877	8/10/2022	8/18/2022	8	0.003%	0.0002
4000466675	144567	2,883	8/10/2022	8/18/2022	8	0.001%	0.0001
4000466694	32964	18,880	8/10/2022	8/18/2022	8	0.005%	0.0004
4000466695	32999	1,162	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466696	33006	310,236	8/10/2022	8/18/2022	8	0.082%	0.0065
4000466697	33037	921,806	8/10/2022	8/18/2022	8	0.243%	0.0195
4000466698	33052	18,660	8/10/2022	8/18/2022	8	0.005%	0.0004
4000466702	33059	30,640	8/10/2022	8/18/2022	8	0.008%	0.0006
4000466703	33061	3,728	8/10/2022	8/18/2022	8	0.001%	0.0001
4000466705	33082	1,422	8/10/2022	8/18/2022	8	0.000%	0.0000
4000466707	33086	7,449	8/10/2022	8/18/2022	8	0.002%	0.0002
4000466713	33128	87,106	8/10/2022	8/18/2022	8	0.023%	0.0018
4000466715	33134	7,428	8/10/2022	8/18/2022	8	0.002%	0.0002
4000466716	33136	4,398	8/10/2022	8/18/2022	8	0.001%	0.0001
4000466718	33138	6,924	8/10/2022	8/18/2022	8	0.002%	0.0001
4000466719	33140	44,063	8/10/2022	8/18/2022	8	0.012%	0.0009
4000466720	33142	18,608	8/10/2022	8/18/2022	8	0.005%	0.0004
4000466742	143694	15,351	8/11/2022	8/19/2022	8	0.004%	0.0003
4000466848	28474	458	8/15/2022	8/23/2022	8	0.000%	0.0000
4000466828	105195	14,319	8/15/2022	8/23/2022	8	0.004%	0.0003
4000466829	115761	106	8/15/2022	8/23/2022	8	0.000%	0.0000
4000466885	9121	2,900	8/16/2022	8/24/2022	8	0.001%	0.0001
4000466888	24383	733	8/16/2022	8/24/2022	8	0.000%	0.0000
4000466889	24825	6,641	8/16/2022	8/24/2022	8	0.002%	0.0001
4000466891	27962	4,616	8/16/2022	8/24/2022	8	0.001%	0.0001
4000466893	34173	15,370	8/16/2022	8/24/2022	8	0.004%	0.0003
4000466859	9145	8,030	8/16/2022	8/24/2022	8	0.002%	0.0002
4000466862	103392	27	8/16/2022	8/24/2022	8	0.000%	0.0000
4000466863	103867	7	8/16/2022	8/24/2022	8	0.000%	0.0000
4000466864	104261	1,545	8/16/2022	8/24/2022	8	0.000%	0.0000
4000466867	116850	2,866	8/16/2022	8/24/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466870	132094	2,656	8/16/2022	8/24/2022	8	0.001%	0.0001
4000466917	9121	1,000	8/17/2022	8/25/2022	8	0.000%	0.0000
4000466918	11304	39,113	8/17/2022	8/25/2022	8	0.010%	0.0008
4000466919	11474	1,275	8/17/2022	8/25/2022	8	0.000%	0.0000
4000466933	27013	13,286	8/17/2022	8/25/2022	8	0.004%	0.0003
4000466935	30475	285	8/17/2022	8/25/2022	8	0.000%	0.0000
4000466904	105208	5,000	8/17/2022	8/25/2022	8	0.001%	0.0001
4000466909	125742	10,200	8/17/2022	8/25/2022	8	0.003%	0.0002
4000466912	138494	5,950	8/17/2022	8/25/2022	8	0.002%	0.0001
4000466916	145139	159,834	8/17/2022	8/25/2022	8	0.042%	0.0034
4000466966	27013	2,390	8/18/2022	8/26/2022	8	0.001%	0.0001
4000466970	33956	450	8/18/2022	8/26/2022	8	0.000%	0.0000
4000466942	15871	480	8/18/2022	8/26/2022	8	0.000%	0.0000
4000466950	125742	1,926	8/18/2022	8/26/2022	8	0.001%	0.0000
4000466952	132094	2,350	8/18/2022	8/26/2022	8	0.001%	0.0000
4000466956	138494	4,165	8/18/2022	8/26/2022	8	0.001%	0.0001
4000466962	144358	24,000	8/18/2022	8/26/2022	8	0.006%	0.0005
4000467061	35151	1,350	8/22/2022	8/30/2022	8	0.000%	0.0000
4000467068	116384	82	8/22/2022	8/30/2022	8	0.000%	0.0000
4000467080	144816	5,190	8/22/2022	8/30/2022	8	0.001%	0.0001
4000467090	103008	768	8/23/2022	8/31/2022	8	0.000%	0.0000
4000467095	142942	10,346	8/23/2022	8/31/2022	8	0.003%	0.0002
4000467098	143659	21,486	8/23/2022	8/31/2022	8	0.006%	0.0005
4000467137	24259	642	8/24/2022	9/1/2022	8	0.000%	0.0000
4000467142	30257	20,012	8/24/2022	9/1/2022	8	0.005%	0.0004
4000467124	122480	5,500	8/24/2022	9/1/2022	8	0.001%	0.0001
4000467125	134862	720,294	8/24/2022	9/1/2022	8	0.190%	0.0152
4000467131	143477	2,222	8/24/2022	9/1/2022	8	0.001%	0.0000
4000467182	24383	838	8/25/2022	9/2/2022	8	0.000%	0.0000
4000467184	26297	3,644	8/25/2022	9/2/2022	8	0.001%	0.0001
4000467191	32537	19,525	8/25/2022	9/2/2022	8	0.005%	0.0004
4000467153	15871	21,381	8/25/2022	9/2/2022	8	0.006%	0.0005
4000467155	27094	1,766	8/25/2022	9/2/2022	8	0.000%	0.0000
4000467152	115795	165	8/25/2022	9/2/2022	8	0.000%	0.0000
4000467319	14949	5,795	8/30/2022	9/7/2022	8	0.002%	0.0001
4000467320	25083	1,099	8/30/2022	9/7/2022	8	0.000%	0.0000
4000467321	25599	8,983	8/30/2022	9/7/2022	8	0.002%	0.0002
4000467327	34064	168	8/30/2022	9/7/2022	8	0.000%	0.0000
4000467330	109948	19,012	8/30/2022	9/7/2022	8	0.005%	0.0004
4000467296	115761	143	8/30/2022	9/7/2022	8	0.000%	0.0000
4000467297	116384	126	8/30/2022	9/7/2022	8	0.000%	0.0000
4000467299	118807	977	8/30/2022	9/7/2022	8	0.000%	0.0000
4000467301	133414	8,856	8/30/2022	9/7/2022	8	0.002%	0.0002
4000467302	139982	9,494	8/30/2022	9/7/2022	8	0.003%	0.0002
4000467305	143312	64,072	8/30/2022	9/7/2022	8	0.017%	0.0014
4000467307	143606	31,031	8/30/2022	9/7/2022	8	0.008%	0.0007
4000467309	143637	3,750	8/30/2022	9/7/2022	8	0.001%	0.0001
4000467375	25908	16,063	8/31/2022	9/8/2022	8	0.004%	0.0003
4000467380	26604	23,085	8/31/2022	9/8/2022	8	0.006%	0.0005
4000467391	117331	447	8/31/2022	9/8/2022	8	0.000%	0.0000
4000467337	15871	885	8/31/2022	9/8/2022	8	0.000%	0.0000
4000467340	34888	20	8/31/2022	9/8/2022	8	0.000%	0.0000
4000467343	107839	2,500	8/31/2022	9/8/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467344	108092	51,264	8/31/2022	9/8/2022	8	0.014%	0.0011
4000467350	118807	1,269	8/31/2022	9/8/2022	8	0.000%	0.0000
4000467354	130634	33,885	8/31/2022	9/8/2022	8	0.009%	0.0007
4000467363	144097	351,267	8/31/2022	9/8/2022	8	0.093%	0.0074
4000467364	144449	1,000	8/31/2022	9/8/2022	8	0.000%	0.0000
4000467365	144567	12,498	8/31/2022	9/8/2022	8	0.003%	0.0003
4000467426	24385	2,624	9/1/2022	9/9/2022	8	0.001%	0.0001
4000467429	26361	7,931	9/1/2022	9/9/2022	8	0.002%	0.0002
4000467402	106674	20,414	9/1/2022	9/9/2022	8	0.005%	0.0004
4000467403	110291	1,880	9/1/2022	9/9/2022	8	0.000%	0.0000
4000467405	116051	200	9/1/2022	9/9/2022	8	0.000%	0.0000
4000467409	139487	1,248	9/1/2022	9/9/2022	8	0.000%	0.0000
4000467413	143072	5,030	9/1/2022	9/9/2022	8	0.001%	0.0001
4000467414	143463	328,062	9/1/2022	9/9/2022	8	0.087%	0.0069
4000467419	144567	56,473	9/1/2022	9/9/2022	8	0.015%	0.0012
4000467557	25659	12,620	9/6/2022	9/14/2022	8	0.003%	0.0003
4000467558	26016	1,721	9/6/2022	9/14/2022	8	0.000%	0.0000
4000467545	118807	2,272	9/6/2022	9/14/2022	8	0.001%	0.0000
4000467554	145067	2,200	9/6/2022	9/14/2022	8	0.001%	0.0000
4000467555	145181	1,200	9/6/2022	9/14/2022	8	0.000%	0.0000
4000467579	26674	1,050	9/7/2022	9/15/2022	8	0.000%	0.0000
4000467564	15871	480	9/7/2022	9/15/2022	8	0.000%	0.0000
4000467569	110291	1,163	9/7/2022	9/15/2022	8	0.000%	0.0000
4000467571	118807	17	9/7/2022	9/15/2022	8	0.000%	0.0000
4000467574	139500	164	9/7/2022	9/15/2022	8	0.000%	0.0000
4000467612	14060	5,100	9/8/2022	9/16/2022	8	0.001%	0.0001
4000467598	139733	622	9/8/2022	9/16/2022	8	0.000%	0.0000
4000467599	142926	27,736	9/8/2022	9/16/2022	8	0.007%	0.0006
4000467603	143577	5,836	9/8/2022	9/16/2022	8	0.002%	0.0001
4000467685	34064	1,307	9/12/2022	9/20/2022	8	0.000%	0.0000
4000467675	134862	506,491	9/12/2022	9/20/2022	8	0.134%	0.0107
4000467679	143340	8,940	9/12/2022	9/20/2022	8	0.002%	0.0002
4000467680	144378	16	9/12/2022	9/20/2022	8	0.000%	0.0000
4000467702	17342	4,860	9/13/2022	9/21/2022	8	0.001%	0.0001
4000467705	25659	11,770	9/13/2022	9/21/2022	8	0.003%	0.0002
4000467706	26490	1,140	9/13/2022	9/21/2022	8	0.000%	0.0000
4000467710	117331	40,000	9/13/2022	9/21/2022	8	0.011%	0.0008
4000467691	32869	10,215	9/13/2022	9/21/2022	8	0.003%	0.0002
4000467693	103867	7	9/13/2022	9/21/2022	8	0.000%	0.0000
4000467697	143426	86,827	9/13/2022	9/21/2022	8	0.023%	0.0018
4000467699	145193	3,238	9/13/2022	9/21/2022	8	0.001%	0.0001
4000467749	11372	1,178	9/14/2022	9/22/2022	8	0.000%	0.0000
4000467750	11474	10,625	9/14/2022	9/22/2022	8	0.003%	0.0002
4000467751	17342	6,615	9/14/2022	9/22/2022	8	0.002%	0.0001
4000467754	25272	865	9/14/2022	9/22/2022	8	0.000%	0.0000
4000467756	25905	1,300	9/14/2022	9/22/2022	8	0.000%	0.0000
4000467758	26363	2,658	9/14/2022	9/22/2022	8	0.001%	0.0001
4000467763	28530	25,614	9/14/2022	9/22/2022	8	0.007%	0.0005
4000467768	34575	5,664	9/14/2022	9/22/2022	8	0.001%	0.0001
4000467715	6396	1,556	9/14/2022	9/22/2022	8	0.000%	0.0000
4000467716	6396	11,458	9/14/2022	9/22/2022	8	0.003%	0.0002
4000467725	116384	70	9/14/2022	9/22/2022	8	0.000%	0.0000
4000467726	120208	500	9/14/2022	9/22/2022	8	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467739	144530	158,805	9/14/2022	9/22/2022	8	0.042%	0.0034
4000467741	145093	3,925	9/14/2022	9/22/2022	8	0.001%	0.0001
4000467744	145330	5,004	9/14/2022	9/22/2022	8	0.001%	0.0001
4000467816	25131	998	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467826	33975	15,707	9/15/2022	9/23/2022	8	0.004%	0.0003
4000467829	106699	12,808	9/15/2022	9/23/2022	8	0.003%	0.0003
4000467776	4765	5,000	9/15/2022	9/23/2022	8	0.001%	0.0001
4000467779	25147	1,582,578	9/15/2022	9/23/2022	8	0.417%	0.0334
4000467783	102637	243	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467784	103008	1,417	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467796	125742	6,400	9/15/2022	9/23/2022	8	0.002%	0.0001
4000467797	126928	27	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467798	129783	159	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467801	139733	400	9/15/2022	9/23/2022	8	0.000%	0.0000
4000467804	142402	100,000	9/15/2022	9/23/2022	8	0.026%	0.0021
4000467772	125852	18,784	9/15/2022	9/23/2022	8	0.005%	0.0004
4000467904	24383	1,255	9/19/2022	9/27/2022	8	0.000%	0.0000
4000467912	117331	100,000	9/19/2022	9/27/2022	8	0.026%	0.0021
4000467891	110291	15,198	9/19/2022	9/27/2022	8	0.004%	0.0003
4000467896	143072	4,622	9/19/2022	9/27/2022	8	0.001%	0.0001
4000467897	143189	48,775	9/19/2022	9/27/2022	8	0.013%	0.0010
4000467899	144567	6,000	9/19/2022	9/27/2022	8	0.002%	0.0001
4000467939	26297	15,193	9/20/2022	9/28/2022	8	0.004%	0.0003
4000467941	26363	1,400	9/20/2022	9/28/2022	8	0.000%	0.0000
4000467922	133414	2,533	9/20/2022	9/28/2022	8	0.001%	0.0001
4000467923	140752	35,479	9/20/2022	9/28/2022	8	0.009%	0.0007
4000467926	142942	11,392	9/20/2022	9/28/2022	8	0.003%	0.0002
4000467929	145211	1,671	9/20/2022	9/28/2022	8	0.000%	0.0000
4000467974	11536	65,285	9/21/2022	9/29/2022	8	0.017%	0.0014
4000467976	26604	148,155	9/21/2022	9/29/2022	8	0.039%	0.0031
4000467977	30475	12,511	9/21/2022	9/29/2022	8	0.003%	0.0003
4000467982	117331	28,900	9/21/2022	9/29/2022	8	0.008%	0.0006
4000467983	124943	380	9/21/2022	9/29/2022	8	0.000%	0.0000
4000467956	108289	213	9/21/2022	9/29/2022	8	0.000%	0.0000
4000467960	125742	1,711	9/21/2022	9/29/2022	8	0.000%	0.0000
4000467961	132507	6,456	9/21/2022	9/29/2022	8	0.002%	0.0001
4000467969	144515	20,403	9/21/2022	9/29/2022	8	0.005%	0.0004
4000467972	144898	19,404	9/21/2022	9/29/2022	8	0.005%	0.0004
4000468016	30475	42,338	9/22/2022	9/30/2022	8	0.011%	0.0009
4000468017	30475	46,384	9/22/2022	9/30/2022	8	0.012%	0.0010
4000468018	30475	53,579	9/22/2022	9/30/2022	8	0.014%	0.0011
4000468019	30475	69,005	9/22/2022	9/30/2022	8	0.018%	0.0015
4000468020	30475	39,788	9/22/2022	9/30/2022	8	0.010%	0.0008
4000468021	32538	408	9/22/2022	9/30/2022	8	0.000%	0.0000
4000468024	117331	33,278	9/22/2022	9/30/2022	8	0.009%	0.0007
4000467986	15871	5,032	9/22/2022	9/30/2022	8	0.001%	0.0001
4000467988	103008	756	9/22/2022	9/30/2022	8	0.000%	0.0000
4000467997	132507	832	9/22/2022	9/30/2022	8	0.000%	0.0000
4000468005	144567	1,545	9/22/2022	9/30/2022	8	0.000%	0.0000
4000468121	26674	2,520	9/26/2022	10/4/2022	8	0.001%	0.0001
4000468095	4502	7,158	9/26/2022	10/4/2022	8	0.002%	0.0002
4000468098	100611	28,220	9/26/2022	10/4/2022	8	0.007%	0.0006
4000468101	108247	3,000	9/26/2022	10/4/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468102	110291	6,375	9/26/2022	10/4/2022	8	0.002%	0.0001
4000468103	116384	55	9/26/2022	10/4/2022	8	0.000%	0.0000
4000468104	118807	735	9/26/2022	10/4/2022	8	0.000%	0.0000
4000468108	141552	13,540	9/26/2022	10/4/2022	8	0.004%	0.0003
4000468110	143072	7,637	9/26/2022	10/4/2022	8	0.002%	0.0002
4000468112	143340	37,013	9/26/2022	10/4/2022	8	0.010%	0.0008
4000468115	145284	12,500	9/26/2022	10/4/2022	8	0.003%	0.0003
4000468151	24113	4,206	9/27/2022	10/5/2022	8	0.001%	0.0001
4000468137	118807	1,291	9/27/2022	10/5/2022	8	0.000%	0.0000
4000468242	9673	8,900	9/28/2022	10/6/2022	8	0.002%	0.0002
4000468245	11372	589	9/28/2022	10/6/2022	8	0.000%	0.0000
4000468248	26639	8,573	9/28/2022	10/6/2022	8	0.002%	0.0002
4000468252	27013	19,997	9/28/2022	10/6/2022	8	0.005%	0.0004
4000468255	30475	3,971	9/28/2022	10/6/2022	8	0.001%	0.0001
4000468257	34173	21,683	9/28/2022	10/6/2022	8	0.006%	0.0005
4000468259	106699	900	9/28/2022	10/6/2022	8	0.000%	0.0000
4000468198	22798	8,000	9/28/2022	10/6/2022	8	0.002%	0.0002
4000468199	26130	62,000	9/28/2022	10/6/2022	8	0.016%	0.0013
4000468200	26958	12,025	9/28/2022	10/6/2022	8	0.003%	0.0003
4000468217	121800	1,000	9/28/2022	10/6/2022	8	0.000%	0.0000
4000468221	125445	2,000	9/28/2022	10/6/2022	8	0.001%	0.0000
4000468222	125742	25,821	9/28/2022	10/6/2022	8	0.007%	0.0005
4000468227	133773	15,000	9/28/2022	10/6/2022	8	0.004%	0.0003
4000468232	143502	58,846	9/28/2022	10/6/2022	8	0.016%	0.0012
4000468234	144663	215,145	9/28/2022	10/6/2022	8	0.057%	0.0045
4000468286	9121	2,850	9/29/2022	10/7/2022	8	0.001%	0.0001
4000468295	24825	3,370	9/29/2022	10/7/2022	8	0.001%	0.0001
4000468296	25599	1,306	9/29/2022	10/7/2022	8	0.000%	0.0000
4000468300	27962	1,425	9/29/2022	10/7/2022	8	0.000%	0.0000
4000468263	15871	15,170	9/29/2022	10/7/2022	8	0.004%	0.0003
4000468265	32869	10,695	9/29/2022	10/7/2022	8	0.003%	0.0002
4000468269	112103	139,779	9/29/2022	10/7/2022	8	0.037%	0.0029
4000468271	121853	757,912	9/29/2022	10/7/2022	8	0.200%	0.0160
4000468431	116384	21	10/3/2022	10/11/2022	8	0.000%	0.0000
4000468498	34658	2,500	10/5/2022	10/13/2022	8	0.001%	0.0001
4000468489	116384	164	10/5/2022	10/13/2022	8	0.000%	0.0000
4000468490	138862	200	10/5/2022	10/13/2022	8	0.000%	0.0000
4000468493	144567	20,723	10/5/2022	10/13/2022	8	0.005%	0.0004
4000468518	13534	76,949	10/6/2022	10/14/2022	8	0.020%	0.0016
4000468521	25659	14,145	10/6/2022	10/14/2022	8	0.004%	0.0003
4000468522	26016	4,672	10/6/2022	10/14/2022	8	0.001%	0.0001
4000468523	26213	7,268	10/6/2022	10/14/2022	8	0.002%	0.0002
4000468532	30475	13,598	10/6/2022	10/14/2022	8	0.004%	0.0003
4000468534	34531	9,688	10/6/2022	10/14/2022	8	0.003%	0.0002
4000468504	27466	2,851	10/6/2022	10/14/2022	8	0.001%	0.0001
4000468510	125742	7,280	10/6/2022	10/14/2022	8	0.002%	0.0002
4000468511	141583	1,040	10/6/2022	10/14/2022	8	0.000%	0.0000
4000468514	143072	26,169	10/6/2022	10/14/2022	8	0.007%	0.0006
4000468641	9673	925	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468642	11426	7,554	10/11/2022	10/19/2022	8	0.002%	0.0002
4000468645	24113	610	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468647	24383	1,570	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468654	26639	3,173	10/11/2022	10/19/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468659	27013	10,419	10/11/2022	10/19/2022	8	0.003%	0.0002
4000468662	28084	14,820	10/11/2022	10/19/2022	8	0.004%	0.0003
4000468671	126775	13,044	10/11/2022	10/19/2022	8	0.003%	0.0003
4000468616	9673	1,025	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468617	24383	1,780	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468625	116384	77	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468628	139733	622	10/11/2022	10/19/2022	8	0.000%	0.0000
4000468633	143659	28,200	10/11/2022	10/19/2022	8	0.007%	0.0006
4000468634	143741	2,100	10/11/2022	10/19/2022	8	0.001%	0.0000
4000468721	9673	925	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468722	11372	784	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468726	25667	700	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468728	26659	623	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468731	27962	456	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468733	30475	41,315	10/12/2022	10/20/2022	8	0.011%	0.0009
4000468734	30475	35,002	10/12/2022	10/20/2022	8	0.009%	0.0007
4000468735	33203	805	10/12/2022	10/20/2022	8	0.000%	0.0000
4000468687	110291	62,046	10/12/2022	10/20/2022	8	0.016%	0.0013
4000468688	110397	10,000	10/12/2022	10/20/2022	8	0.003%	0.0002
4000468694	119888	5,000	10/12/2022	10/20/2022	8	0.001%	0.0001
4000468696	123032	10,000	10/12/2022	10/20/2022	8	0.003%	0.0002
4000468874	24385	1,286	10/17/2022	10/25/2022	8	0.000%	0.0000
4000468885	26659	42,949	10/17/2022	10/25/2022	8	0.011%	0.0009
4000468890	34064	1,946	10/17/2022	10/25/2022	8	0.001%	0.0000
4000468847	4502	49,296	10/17/2022	10/25/2022	8	0.013%	0.0010
4000468850	24383	1,240	10/17/2022	10/25/2022	8	0.000%	0.0000
4000468857	116384	610	10/17/2022	10/25/2022	8	0.000%	0.0000
4000468922	8392	20,572	10/18/2022	10/26/2022	8	0.005%	0.0004
4000468926	24999	1,478	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468927	25083	1,917	10/18/2022	10/26/2022	8	0.001%	0.0000
4000468929	26356	594	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468899	102060	88	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468901	102637	168	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468903	103603	2,927	10/18/2022	10/26/2022	8	0.001%	0.0001
4000468905	103913	70	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468906	104154	352	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468910	118807	563	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468913	133875	181	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468920	143270	1,001	10/18/2022	10/26/2022	8	0.000%	0.0000
4000468953	24383	2,148	10/19/2022	10/27/2022	8	0.001%	0.0000
4000468956	25131	665	10/19/2022	10/27/2022	8	0.000%	0.0000
4000468959	28737	3,831	10/19/2022	10/27/2022	8	0.001%	0.0001
4000468960	30475	47,119	10/19/2022	10/27/2022	8	0.012%	0.0010
4000468961	30475	26,219	10/19/2022	10/27/2022	8	0.007%	0.0006
4000468962	30475	28,370	10/19/2022	10/27/2022	8	0.007%	0.0006
4000468963	30475	29,857	10/19/2022	10/27/2022	8	0.008%	0.0006
4000468964	30475	31,698	10/19/2022	10/27/2022	8	0.008%	0.0007
4000468965	30475	33,595	10/19/2022	10/27/2022	8	0.009%	0.0007
4000468966	30475	38,188	10/19/2022	10/27/2022	8	0.010%	0.0008
4000469032	33078	4,740	10/19/2022	10/27/2022	8	0.001%	0.0001
4000468948	144567	12,655	10/19/2022	10/27/2022	8	0.003%	0.0003
4000468972	32928	82,246	10/19/2022	10/27/2022	8	0.022%	0.0017
4000468974	32941	171,394	10/19/2022	10/27/2022	8	0.045%	0.0036

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468979	32957	1,692	10/19/2022	10/27/2022	8	0.000%	0.0000
4000468980	32965	5,052	10/19/2022	10/27/2022	8	0.001%	0.0001
4000468981	32967	10,202	10/19/2022	10/27/2022	8	0.003%	0.0002
4000468989	32985	5,320	10/19/2022	10/27/2022	8	0.001%	0.0001
4000468990	32990	5,295	10/19/2022	10/27/2022	8	0.001%	0.0001
4000468991	33001	98,207	10/19/2022	10/27/2022	8	0.026%	0.0021
4000468993	33010	18,116	10/19/2022	10/27/2022	8	0.005%	0.0004
4000468994	33013	7,339	10/19/2022	10/27/2022	8	0.002%	0.0002
4000468996	33015	6,341	10/19/2022	10/27/2022	8	0.002%	0.0001
4000468997	33022	11,513	10/19/2022	10/27/2022	8	0.003%	0.0002
4000468998	33026	839	10/19/2022	10/27/2022	8	0.000%	0.0000
4000468999	33029	8,709	10/19/2022	10/27/2022	8	0.002%	0.0002
4000469000	33030	105,133	10/19/2022	10/27/2022	8	0.028%	0.0022
4000469002	33032	1,355	10/19/2022	10/27/2022	8	0.000%	0.0000
4000469003	33034	1,404	10/19/2022	10/27/2022	8	0.000%	0.0000
4000469007	33047	15,410	10/19/2022	10/27/2022	8	0.004%	0.0003
4000469009	33061	8	10/19/2022	10/27/2022	8	0.000%	0.0000
4000469011	33064	32,991	10/19/2022	10/27/2022	8	0.009%	0.0007
4000469016	33077	14,304	10/19/2022	10/27/2022	8	0.004%	0.0003
4000469018	33084	1,381	10/19/2022	10/27/2022	8	0.000%	0.0000
4000469020	33098	37,083	10/19/2022	10/27/2022	8	0.010%	0.0008
4000469021	33104	84,462	10/19/2022	10/27/2022	8	0.022%	0.0018
4000469022	33114	119,343	10/19/2022	10/27/2022	8	0.031%	0.0025
4000469023	33120	65,794	10/19/2022	10/27/2022	8	0.017%	0.0014
4000469024	33122	20,515	10/19/2022	10/27/2022	8	0.005%	0.0004
4000469029	33148	2,098	10/19/2022	10/27/2022	8	0.001%	0.0000
4000469030	112304	21,478	10/19/2022	10/27/2022	8	0.006%	0.0005
4000469059	24113	2,218	10/20/2022	10/28/2022	8	0.001%	0.0000
4000469062	26323	8,385	10/20/2022	10/28/2022	8	0.002%	0.0002
4000469033	15871	1,228	10/20/2022	10/28/2022	8	0.000%	0.0000
4000469035	26256	4,875	10/20/2022	10/28/2022	8	0.001%	0.0001
4000469037	103008	21	10/20/2022	10/28/2022	8	0.000%	0.0000
4000469043	125742	23,760	10/20/2022	10/28/2022	8	0.006%	0.0005
4000469046	132507	808	10/20/2022	10/28/2022	8	0.000%	0.0000
4000469136	103392	154	10/24/2022	11/1/2022	8	0.000%	0.0000
4000469149	142942	5,070	10/24/2022	11/1/2022	8	0.001%	0.0001
4000469151	143588	10,678	10/24/2022	11/1/2022	8	0.003%	0.0002
4000469153	144567	43,540	10/24/2022	11/1/2022	8	0.011%	0.0009
4000469196	24383	1,741	10/25/2022	11/2/2022	8	0.000%	0.0000
4000469174	118807	471	10/25/2022	11/2/2022	8	0.000%	0.0000
4000469181	142874	12,939	10/25/2022	11/2/2022	8	0.003%	0.0003
4000469184	144567	4,201	10/25/2022	11/2/2022	8	0.001%	0.0001
4000469234	11260	8,912	10/26/2022	11/3/2022	8	0.002%	0.0002
4000469235	17342	8,033	10/26/2022	11/3/2022	8	0.002%	0.0002
4000469239	25659	28,663	10/26/2022	11/3/2022	8	0.008%	0.0006
4000469240	26016	1,374	10/26/2022	11/3/2022	8	0.000%	0.0000
4000469241	26213	2,254	10/26/2022	11/3/2022	8	0.001%	0.0000
4000469242	26604	28,570	10/26/2022	11/3/2022	8	0.008%	0.0006
4000469243	26639	3,915	10/26/2022	11/3/2022	8	0.001%	0.0001
4000469253	124943	2,090	10/26/2022	11/3/2022	8	0.001%	0.0000
4000469212	110291	4,687	10/26/2022	11/3/2022	8	0.001%	0.0001
4000469213	112927	1,100	10/26/2022	11/3/2022	8	0.000%	0.0000
4000469214	115658	7,500	10/26/2022	11/3/2022	8	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469215	116051	100	10/26/2022	11/3/2022	8	0.000%	0.0000
4000469226	143340	12,495	10/26/2022	11/3/2022	8	0.003%	0.0003
4000469228	144097	103,838	10/26/2022	11/3/2022	8	0.027%	0.0022
4000469295	11305	3,131	10/27/2022	11/4/2022	8	0.001%	0.0001
4000469297	24113	993	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469300	24385	1,166	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469311	27013	420	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469319	105195	49,665	10/27/2022	11/4/2022	8	0.013%	0.0010
4000469320	106699	1,463	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469324	134272	28,259	10/27/2022	11/4/2022	8	0.007%	0.0006
4000469262	4765	66,194	10/27/2022	11/4/2022	8	0.017%	0.0014
4000469263	15871	3,471	10/27/2022	11/4/2022	8	0.001%	0.0001
4000469268	103990	133	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469270	105195	7,145	10/27/2022	11/4/2022	8	0.002%	0.0002
4000469280	139487	600	10/27/2022	11/4/2022	8	0.000%	0.0000
4000469283	142642	6,710	10/27/2022	11/4/2022	8	0.002%	0.0001
4000469286	143072	6,848	10/27/2022	11/4/2022	8	0.002%	0.0001
4000469328	33021	115,178	10/27/2022	11/4/2022	8	0.030%	0.0024
4000469259	126568	37,167	10/27/2022	11/4/2022	8	0.010%	0.0008
4000469291	116971	3,000	10/27/2022	11/4/2022	8	0.001%	0.0001
4000469451	34064	240,860	10/31/2022	11/8/2022	8	0.064%	0.0051
4000469453	124943	1,520	10/31/2022	11/8/2022	8	0.000%	0.0000
4000469402	4502	10,872	10/31/2022	11/8/2022	8	0.003%	0.0002
4000469406	28348	1,035	10/31/2022	11/8/2022	8	0.000%	0.0000
4000469413	116384	96	10/31/2022	11/8/2022	8	0.000%	0.0000
4000469426	144567	2,500	10/31/2022	11/8/2022	8	0.001%	0.0001
4000469427	144663	239,567	10/31/2022	11/8/2022	8	0.063%	0.0051
4000469471	25659	13,418	11/1/2022	11/9/2022	8	0.004%	0.0003
4000469472	25708	1,178	11/1/2022	11/9/2022	8	0.000%	0.0000
4000469477	26604	32,715	11/1/2022	11/9/2022	8	0.009%	0.0007
4000469478	26639	13,028	11/1/2022	11/9/2022	8	0.003%	0.0003
4000469479	27013	3,555	11/1/2022	11/9/2022	8	0.001%	0.0001
4000469481	30475	13,761	11/1/2022	11/9/2022	8	0.004%	0.0003
4000469459	116384	340	11/1/2022	11/9/2022	8	0.000%	0.0000
4000469533	26604	3,855	11/2/2022	11/10/2022	8	0.001%	0.0001
4000469535	28737	896	11/2/2022	11/10/2022	8	0.000%	0.0000
4000469542	34341	7,700	11/2/2022	11/10/2022	8	0.002%	0.0002
4000469494	116384	15	11/2/2022	11/10/2022	8	0.000%	0.0000
4000469499	134862	1,373,149	11/2/2022	11/10/2022	8	0.362%	0.0290
4000469502	138494	20,800	11/2/2022	11/10/2022	8	0.005%	0.0004
4000469513	143270	4,500	11/2/2022	11/10/2022	8	0.001%	0.0001
4000469517	144410	2,850	11/2/2022	11/10/2022	8	0.001%	0.0001
4000469521	144573	4,000	11/2/2022	11/10/2022	8	0.001%	0.0001
4000469524	144927	6,000	11/2/2022	11/10/2022	8	0.002%	0.0001
4000469526	144996	2,500	11/2/2022	11/10/2022	8	0.001%	0.0001
4000469527	145034	11,345	11/2/2022	11/10/2022	8	0.003%	0.0002
4000469530	145245	11,043	11/2/2022	11/10/2022	8	0.003%	0.0002
4000469666	118807	165	11/7/2022	11/15/2022	8	0.000%	0.0000
4000469673	143340	929	11/7/2022	11/15/2022	8	0.000%	0.0000
4000469694	142942	8,977	11/8/2022	11/16/2022	8	0.002%	0.0002
4000469697	143340	1,840	11/8/2022	11/16/2022	8	0.000%	0.0000
4000469745	14949	4,489	11/9/2022	11/17/2022	8	0.001%	0.0001
4000469747	20063	4,114	11/9/2022	11/17/2022	8	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469754	26207	950	11/9/2022	11/17/2022	8	0.000%	0.0000
4000469758	26642	751	11/9/2022	11/17/2022	8	0.000%	0.0000
4000469760	27704	4,050	11/9/2022	11/17/2022	8	0.001%	0.0001
4000469765	33203	12,708	11/9/2022	11/17/2022	8	0.003%	0.0003
4000469766	33956	3,629	11/9/2022	11/17/2022	8	0.001%	0.0001
4000469769	117331	1,900	11/9/2022	11/17/2022	8	0.001%	0.0000
4000469709	4765	8,000	11/9/2022	11/17/2022	8	0.002%	0.0002
4000469729	142926	22,879	11/9/2022	11/17/2022	8	0.006%	0.0005
4000469734	143941	8,192	11/9/2022	11/17/2022	8	0.002%	0.0002
4000469742	145470	250	11/9/2022	11/17/2022	8	0.000%	0.0000
4000469784	112215	3,550	11/10/2022	11/18/2022	8	0.001%	0.0001
4000469805	143694	3,756	11/10/2022	11/18/2022	8	0.001%	0.0001
4000469863	26604	15,390	11/14/2022	11/22/2022	8	0.004%	0.0003
4000469867	124943	380	11/14/2022	11/22/2022	8	0.000%	0.0000
4000469841	108149	60	11/14/2022	11/22/2022	8	0.000%	0.0000
4000469844	116384	80	11/14/2022	11/22/2022	8	0.000%	0.0000
4000469847	133414	10,160	11/14/2022	11/22/2022	8	0.003%	0.0002
4000469848	134862	171,287	11/14/2022	11/22/2022	8	0.045%	0.0036
4000469852	143312	31,097	11/14/2022	11/22/2022	8	0.008%	0.0007
4000469853	143463	96,222	11/14/2022	11/22/2022	8	0.025%	0.0020
4000469856	144816	1,145	11/14/2022	11/22/2022	8	0.000%	0.0000
4000469834	103952	3,500	11/14/2022	11/22/2022	8	0.001%	0.0001
4000469890	9121	1,050	11/15/2022	11/23/2022	8	0.000%	0.0000
4000469871	6396	1,000	11/15/2022	11/23/2022	8	0.000%	0.0000
4000469872	15871	2,357	11/15/2022	11/23/2022	8	0.001%	0.0000
4000469874	103392	35	11/15/2022	11/23/2022	8	0.000%	0.0000
4000469875	104496	35	11/15/2022	11/23/2022	8	0.000%	0.0000
4000469879	125742	564	11/15/2022	11/23/2022	8	0.000%	0.0000
4000469982	24383	1,990	11/17/2022	11/25/2022	8	0.001%	0.0000
4000469983	26296	378	11/17/2022	11/25/2022	8	0.000%	0.0000
4000469984	26356	638	11/17/2022	11/25/2022	8	0.000%	0.0000
4000469987	30475	38,370	11/17/2022	11/25/2022	8	0.010%	0.0008
4000469988	30475	48,665	11/17/2022	11/25/2022	8	0.013%	0.0010
4000469958	12081	1,978	11/17/2022	11/25/2022	8	0.001%	0.0000
4000469964	110291	182	11/17/2022	11/25/2022	8	0.000%	0.0000
4000469968	133414	458	11/17/2022	11/25/2022	8	0.000%	0.0000
4000469978	144816	435	11/17/2022	11/25/2022	8	0.000%	0.0000
4000469979	145343	11,515	11/17/2022	11/25/2022	8	0.003%	0.0002
4000470090	14060	788	11/21/2022	11/29/2022	8	0.000%	0.0000
4000470059	111669	196	11/21/2022	11/29/2022	8	0.000%	0.0000
4000470062	118807	589	11/21/2022	11/29/2022	8	0.000%	0.0000
4000470069	134862	302,817	11/21/2022	11/29/2022	8	0.080%	0.0064
4000470071	138862	600	11/21/2022	11/29/2022	8	0.000%	0.0000
4000470080	144663	222,511	11/21/2022	11/29/2022	8	0.059%	0.0047
4000470083	145494	1,000	11/21/2022	11/29/2022	8	0.000%	0.0000
4000470104	26130	42,000	11/22/2022	11/30/2022	8	0.011%	0.0009
4000470105	103392	55	11/22/2022	11/30/2022	8	0.000%	0.0000
4000470106	104261	80	11/22/2022	11/30/2022	8	0.000%	0.0000
4000470108	106840	39	11/22/2022	11/30/2022	8	0.000%	0.0000
4000470114	129757	49	11/22/2022	11/30/2022	8	0.000%	0.0000
4000470115	130315	39	11/22/2022	11/30/2022	8	0.000%	0.0000
4000470125	145372	294,309	11/22/2022	11/30/2022	8	0.078%	0.0062
4000470126	145372	294,309	11/22/2022	11/30/2022	8	0.078%	0.0062

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470127	145372	294,309	11/22/2022	11/30/2022	8	0.078%	0.0062
4000470128	145372	326,677	11/22/2022	11/30/2022	8	0.086%	0.0069
4000470129	145372	326,677	11/22/2022	11/30/2022	8	0.086%	0.0069
4000470130	145372	326,677	11/22/2022	11/30/2022	8	0.086%	0.0069
4000470253	24281	17,024	11/28/2022	12/6/2022	8	0.004%	0.0004
4000470276	124943	760	11/28/2022	12/6/2022	8	0.000%	0.0000
4000470232	103392	44	11/28/2022	12/6/2022	8	0.000%	0.0000
4000470236	118807	625	11/28/2022	12/6/2022	8	0.000%	0.0000
4000470241	143463	40,087	11/28/2022	12/6/2022	8	0.011%	0.0008
4000470243	143584	14,467	11/28/2022	12/6/2022	8	0.004%	0.0003
4000470298	11260	10,768	11/29/2022	12/7/2022	8	0.003%	0.0002
4000470301	25659	29,125	11/29/2022	12/7/2022	8	0.008%	0.0006
4000470302	26297	7,434	11/29/2022	12/7/2022	8	0.002%	0.0002
4000470304	26323	3,118	11/29/2022	12/7/2022	8	0.001%	0.0001
4000470307	26655	4,833	11/29/2022	12/7/2022	8	0.001%	0.0001
4000470283	111770	291	11/29/2022	12/7/2022	8	0.000%	0.0000
4000470288	143426	179,470	11/29/2022	12/7/2022	8	0.047%	0.0038
4000470349	14949	12,710	11/30/2022	12/8/2022	8	0.003%	0.0003
4000470358	25908	24,313	11/30/2022	12/8/2022	8	0.006%	0.0005
4000470362	26604	4,350	11/30/2022	12/8/2022	8	0.001%	0.0001
4000470365	26668	17,010	11/30/2022	12/8/2022	8	0.004%	0.0004
4000470366	26674	4,340	11/30/2022	12/8/2022	8	0.001%	0.0001
4000470373	32537	1,210	11/30/2022	12/8/2022	8	0.000%	0.0000
4000470374	32808	1,320	11/30/2022	12/8/2022	8	0.000%	0.0000
4000470375	32896	3,800	11/30/2022	12/8/2022	8	0.001%	0.0001
4000470382	34531	20,336	11/30/2022	12/8/2022	8	0.005%	0.0004
4000470312	6351	344,430	11/30/2022	12/8/2022	8	0.091%	0.0073
4000470313	25147	257,968	11/30/2022	12/8/2022	8	0.068%	0.0054
4000470317	27466	3,168	11/30/2022	12/8/2022	8	0.001%	0.0001
4000470320	32869	10,000	11/30/2022	12/8/2022	8	0.003%	0.0002
4000470321	116384	138	11/30/2022	12/8/2022	8	0.000%	0.0000
4000470324	121825	37,437	11/30/2022	12/8/2022	8	0.010%	0.0008
4000470340	144982	2,070	11/30/2022	12/8/2022	8	0.001%	0.0000
4000470311	145478	4,586	11/30/2022	12/8/2022	8	0.001%	0.0001
4000470446	34064	242,500	12/1/2022	12/9/2022	8	0.064%	0.0051
4000470447	34069	6,730	12/1/2022	12/9/2022	8	0.002%	0.0001
4000470395	26130	63,975	12/1/2022	12/9/2022	8	0.017%	0.0013
4000470401	108092	2,150	12/1/2022	12/9/2022	8	0.001%	0.0000
4000470403	112519	5,000	12/1/2022	12/9/2022	8	0.001%	0.0001
4000470405	116384	207	12/1/2022	12/9/2022	8	0.000%	0.0000
4000470408	125742	5,680	12/1/2022	12/9/2022	8	0.001%	0.0001
4000470414	138494	20,000	12/1/2022	12/9/2022	8	0.005%	0.0004
4000470415	139487	308	12/1/2022	12/9/2022	8	0.000%	0.0000
4000470423	143577	6,937	12/1/2022	12/9/2022	8	0.002%	0.0001
4000470542	104509	11,102	12/5/2022	12/13/2022	8	0.003%	0.0002
4000470549	127624	2,500	12/5/2022	12/13/2022	8	0.001%	0.0001
4000470551	132849	790	12/5/2022	12/13/2022	8	0.000%	0.0000
4000470556	143340	18,929	12/5/2022	12/13/2022	8	0.005%	0.0004
4000470557	143659	4,602	12/5/2022	12/13/2022	8	0.001%	0.0001
4000470588	24281	17,973	12/6/2022	12/14/2022	8	0.005%	0.0004
4000470591	26639	12,083	12/6/2022	12/14/2022	8	0.003%	0.0003
4000470578	112215	1,420	12/6/2022	12/14/2022	8	0.000%	0.0000
4000470584	143340	407,221	12/6/2022	12/14/2022	8	0.107%	0.0086

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470630	11372	2,802	12/7/2022	12/15/2022	8	0.001%	0.0001
4000470633	26207	3,275	12/7/2022	12/15/2022	8	0.001%	0.0001
4000470635	26301	6,891	12/7/2022	12/15/2022	8	0.002%	0.0001
4000470646	124943	1,140	12/7/2022	12/15/2022	8	0.000%	0.0000
4000470598	4502	2,310	12/7/2022	12/15/2022	8	0.001%	0.0000
4000470604	36411	31,318	12/7/2022	12/15/2022	8	0.008%	0.0007
4000470608	107047	6,160	12/7/2022	12/15/2022	8	0.002%	0.0001
4000470609	110397	25,000	12/7/2022	12/15/2022	8	0.007%	0.0005
4000470610	111770	249	12/7/2022	12/15/2022	8	0.000%	0.0000
4000470616	141256	36	12/7/2022	12/15/2022	8	0.000%	0.0000
4000470618	142062	500	12/7/2022	12/15/2022	8	0.000%	0.0000
4000470622	142996	17,925	12/7/2022	12/15/2022	8	0.005%	0.0004
4000470626	144816	5,452	12/7/2022	12/15/2022	8	0.001%	0.0001
4000470679	26659	2,493	12/8/2022	12/16/2022	8	0.001%	0.0001
4000470650	26471	52,032	12/8/2022	12/16/2022	8	0.014%	0.0011
4000470652	35151	990	12/8/2022	12/16/2022	8	0.000%	0.0000
4000470656	110291	14,740	12/8/2022	12/16/2022	8	0.004%	0.0003
4000470657	110291	62,780	12/8/2022	12/16/2022	8	0.017%	0.0013
4000470658	110291	71,939	12/8/2022	12/16/2022	8	0.019%	0.0015
4000470663	143941	8,193	12/8/2022	12/16/2022	8	0.002%	0.0002
4000470766	24191	8,340	12/12/2022	12/20/2022	8	0.002%	0.0002
4000470779	117331	30,000	12/12/2022	12/20/2022	8	0.008%	0.0006
4000470747	110291	15,020	12/12/2022	12/20/2022	8	0.004%	0.0003
4000470748	112215	1,180	12/12/2022	12/20/2022	8	0.000%	0.0000
4000470759	144567	20,413	12/12/2022	12/20/2022	8	0.005%	0.0004
4000470797	11260	8,487	12/13/2022	12/21/2022	8	0.002%	0.0002
4000470798	26213	5,658	12/13/2022	12/21/2022	8	0.001%	0.0001
4000470799	26297	874	12/13/2022	12/21/2022	8	0.000%	0.0000
4000470800	26356	7,781	12/13/2022	12/21/2022	8	0.002%	0.0002
4000470801	26577	2,100	12/13/2022	12/21/2022	8	0.001%	0.0000
4000470804	28084	14,868	12/13/2022	12/21/2022	8	0.004%	0.0003
4000470787	134862	18,656	12/13/2022	12/21/2022	8	0.005%	0.0004
4000470789	143463	53,703	12/13/2022	12/21/2022	8	0.014%	0.0011
4000470836	5673	6,800	12/14/2022	12/22/2022	8	0.002%	0.0001
4000470839	11305	2,535	12/14/2022	12/22/2022	8	0.001%	0.0001
4000470843	17342	540	12/14/2022	12/22/2022	8	0.000%	0.0000
4000470845	23701	15,000	12/14/2022	12/22/2022	8	0.004%	0.0003
4000470847	24259	5,910	12/14/2022	12/22/2022	8	0.002%	0.0001
4000470849	25808	720	12/14/2022	12/22/2022	8	0.000%	0.0000
4000470852	26338	3,755	12/14/2022	12/22/2022	8	0.001%	0.0001
4000470853	26361	1,900	12/14/2022	12/22/2022	8	0.001%	0.0000
4000470855	26604	28,235	12/14/2022	12/22/2022	8	0.007%	0.0006
4000470859	28474	3,352	12/14/2022	12/22/2022	8	0.001%	0.0001
4000470867	117331	40,800	12/14/2022	12/22/2022	8	0.011%	0.0009
4000470816	104122	49,205	12/14/2022	12/22/2022	8	0.013%	0.0010
4000470820	110291	6,026	12/14/2022	12/22/2022	8	0.002%	0.0001
4000470821	116384	726	12/14/2022	12/22/2022	8	0.000%	0.0000
4000470833	143796	3,944	12/14/2022	12/22/2022	8	0.001%	0.0001
4000470911	30196	840	12/15/2022	12/23/2022	8	0.000%	0.0000
4000470873	6396	108,608	12/15/2022	12/23/2022	8	0.029%	0.0023
4000470876	27094	1,766	12/15/2022	12/23/2022	8	0.000%	0.0000
4000470883	110291	28,142	12/15/2022	12/23/2022	8	0.007%	0.0006
4000470888	134862	94,759	12/15/2022	12/23/2022	8	0.025%	0.0020

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470890	138862	265	12/15/2022	12/23/2022	8	0.000%	0.0000
4000470891	139733	54	12/15/2022	12/23/2022	8	0.000%	0.0000
4000470894	142942	3,179	12/15/2022	12/23/2022	8	0.001%	0.0001
4000470897	144487	11,419	12/15/2022	12/23/2022	8	0.003%	0.0002
4000471088	25083	807	12/20/2022	12/28/2022	8	0.000%	0.0000
4000471099	28474	1,869	12/20/2022	12/28/2022	8	0.000%	0.0000
4000471103	32538	2,586	12/20/2022	12/28/2022	8	0.001%	0.0001
4000471059	106840	112	12/20/2022	12/28/2022	8	0.000%	0.0000
4000471066	130315	39	12/20/2022	12/28/2022	8	0.000%	0.0000
4000471067	132094	1,261	12/20/2022	12/28/2022	8	0.000%	0.0000
4000471068	134862	771,133	12/20/2022	12/28/2022	8	0.203%	0.0163
4000471142	14949	2,570	12/21/2022	12/29/2022	8	0.001%	0.0001
4000471153	26356	1,116	12/21/2022	12/29/2022	8	0.000%	0.0000
4000471163	26674	1,260	12/21/2022	12/29/2022	8	0.000%	0.0000
4000471107	4502	33,096	12/21/2022	12/29/2022	8	0.009%	0.0007
4000471108	13672	1,963	12/21/2022	12/29/2022	8	0.001%	0.0000
4000471127	143340	25,626	12/21/2022	12/29/2022	8	0.007%	0.0005
4000471128	143463	153,024	12/21/2022	12/29/2022	8	0.040%	0.0032
4000471129	143584	106,985	12/21/2022	12/29/2022	8	0.028%	0.0023
4000471133	144982	2,791	12/21/2022	12/29/2022	8	0.001%	0.0001
4000471283	18267	1,454	12/27/2022	1/4/2023	8	0.000%	0.0000
4000471286	24385	3,201	12/27/2022	1/4/2023	8	0.001%	0.0001
4000471269	103392	78	12/27/2022	1/4/2023	8	0.000%	0.0000
4000471273	118807	1,254	12/27/2022	1/4/2023	8	0.000%	0.0000
4000471274	132094	1,330	12/27/2022	1/4/2023	8	0.000%	0.0000
4000471277	143414	54,770	12/27/2022	1/4/2023	8	0.014%	0.0012
4000471317	11426	24,354	12/28/2022	1/5/2023	8	0.006%	0.0005
4000471323	26604	11,405	12/28/2022	1/5/2023	8	0.003%	0.0002
4000471324	26659	1,122	12/28/2022	1/5/2023	8	0.000%	0.0000
4000471332	34341	7,700	12/28/2022	1/5/2023	8	0.002%	0.0002
4000471333	34575	1,325	12/28/2022	1/5/2023	8	0.000%	0.0000
4000471336	117331	413	12/28/2022	1/5/2023	8	0.000%	0.0000
4000471301	21678	27,813	12/28/2022	1/5/2023	8	0.007%	0.0006
4000471302	22902	1,595	12/28/2022	1/5/2023	8	0.000%	0.0000
4000471303	27094	19,424	12/28/2022	1/5/2023	8	0.005%	0.0004
4000471306	111770	291	12/28/2022	1/5/2023	8	0.000%	0.0000
4000471307	112103	86,071	12/28/2022	1/5/2023	8	0.023%	0.0018
4000471316	145343	11,411	12/28/2022	1/5/2023	8	0.003%	0.0002
4000471369	9121	33,750	12/29/2022	1/6/2023	8	0.009%	0.0007
4000471370	11260	6,949	12/29/2022	1/6/2023	8	0.002%	0.0001
4000471375	14949	4,332	12/29/2022	1/6/2023	8	0.001%	0.0001
4000471388	26297	53,785	12/29/2022	1/6/2023	8	0.014%	0.0011
4000471397	26490	950	12/29/2022	1/6/2023	8	0.000%	0.0000
4000471399	26655	1,800	12/29/2022	1/6/2023	8	0.000%	0.0000
4000471400	26659	19,573	12/29/2022	1/6/2023	8	0.005%	0.0004
4000471401	26674	1,540	12/29/2022	1/6/2023	8	0.000%	0.0000
4000471403	28084	6,888	12/29/2022	1/6/2023	8	0.002%	0.0001
4000471406	30257	8,190	12/29/2022	1/6/2023	8	0.002%	0.0002
4000471409	34088	9,900	12/29/2022	1/6/2023	8	0.003%	0.0002
4000471411	117331	10,000	12/29/2022	1/6/2023	8	0.003%	0.0002
4000471345	27094	42,270	12/29/2022	1/6/2023	8	0.011%	0.0009
4000471352	118807	3,521	12/29/2022	1/6/2023	8	0.001%	0.0001
4000471353	125742	8,280	12/29/2022	1/6/2023	8	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471358	143072	39,732	12/29/2022	1/6/2023	8	0.010%	0.0008
4000471359	143338	20,110	12/29/2022	1/6/2023	8	0.005%	0.0004
4000471360	143477	2,032	12/29/2022	1/6/2023	8	0.001%	0.0000
4000471361	143577	1,718	12/29/2022	1/6/2023	8	0.000%	0.0000
4000459543	103008	3,277	1/3/2022	1/12/2022	9	0.001%	0.0001
4000459544	103392	17	1/3/2022	1/12/2022	9	0.000%	0.0000
4000459547	129857	12,211	1/3/2022	1/12/2022	9	0.003%	0.0003
4000459550	140752	9,273	1/3/2022	1/12/2022	9	0.002%	0.0002
4000459572	4765	2,000	1/4/2022	1/13/2022	9	0.001%	0.0000
4000459578	129031	504	1/4/2022	1/13/2022	9	0.000%	0.0000
4000459603	25173	5,280	1/5/2022	1/14/2022	9	0.001%	0.0001
4000459592	103392	311	1/5/2022	1/14/2022	9	0.000%	0.0000
4000459594	116384	1,315	1/5/2022	1/14/2022	9	0.000%	0.0000
4000459701	103008	163	1/10/2022	1/19/2022	9	0.000%	0.0000
4000459755	13534	12,928	1/11/2022	1/20/2022	9	0.003%	0.0003
4000459759	25131	380	1/11/2022	1/20/2022	9	0.000%	0.0000
4000459762	25808	4,380	1/11/2022	1/20/2022	9	0.001%	0.0001
4000459763	27013	2,361	1/11/2022	1/20/2022	9	0.001%	0.0001
4000459764	27305	9,500	1/11/2022	1/20/2022	9	0.003%	0.0002
4000459765	30228	104,883	1/11/2022	1/20/2022	9	0.028%	0.0025
4000459770	124943	720	1/11/2022	1/20/2022	9	0.000%	0.0000
4000459740	10055	44,582	1/11/2022	1/20/2022	9	0.012%	0.0011
4000459745	104195	44	1/11/2022	1/20/2022	9	0.000%	0.0000
4000459747	118807	21	1/11/2022	1/20/2022	9	0.000%	0.0000
4000459749	140752	332	1/11/2022	1/20/2022	9	0.000%	0.0000
4000459751	143011	7,380	1/11/2022	1/20/2022	9	0.002%	0.0002
4000459774	4502	251,279	1/12/2022	1/21/2022	9	0.066%	0.0060
4000459778	129387	61,911	1/12/2022	1/21/2022	9	0.016%	0.0015
4000459779	137204	17,067	1/12/2022	1/21/2022	9	0.005%	0.0004
4000459783	143577	12,063	1/12/2022	1/21/2022	9	0.003%	0.0003
4000459773	144442	179,900	1/12/2022	1/21/2022	9	0.047%	0.0043
4000459986	11474	5,650	1/18/2022	1/27/2022	9	0.001%	0.0001
4000459987	11577	578	1/18/2022	1/27/2022	9	0.000%	0.0000
4000459989	18267	4,742	1/18/2022	1/27/2022	9	0.001%	0.0001
4000459996	26016	2,315	1/18/2022	1/27/2022	9	0.001%	0.0001
4000459963	105195	1,057	1/18/2022	1/27/2022	9	0.000%	0.0000
4000459969	141256	1,716	1/18/2022	1/27/2022	9	0.000%	0.0000
4000459980	144682	72,730	1/18/2022	1/27/2022	9	0.019%	0.0017
4000460045	33924	21,537	1/19/2022	1/28/2022	9	0.006%	0.0005
4000460051	130375	30,173	1/19/2022	1/28/2022	9	0.008%	0.0007
4000460017	116384	314	1/19/2022	1/28/2022	9	0.000%	0.0000
4000460026	144047	200	1/19/2022	1/28/2022	9	0.000%	0.0000
4000460013	114121	4,025	1/19/2022	1/28/2022	9	0.001%	0.0001
4000460151	11426	9,669	1/24/2022	2/2/2022	9	0.003%	0.0002
4000460152	14949	19,937	1/24/2022	2/2/2022	9	0.005%	0.0005
4000460155	26297	323	1/24/2022	2/2/2022	9	0.000%	0.0000
4000460158	26363	1,338	1/24/2022	2/2/2022	9	0.000%	0.0000
4000460133	116384	495	1/24/2022	2/2/2022	9	0.000%	0.0000
4000460170	32973	450	1/24/2022	2/2/2022	9	0.000%	0.0000
4000460173	32980	7,756	1/24/2022	2/2/2022	9	0.002%	0.0002
4000460177	33007	7,721	1/24/2022	2/2/2022	9	0.002%	0.0002
4000460178	33009	538,341	1/24/2022	2/2/2022	9	0.142%	0.0128
4000460179	33010	27,990	1/24/2022	2/2/2022	9	0.007%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460187	33020	63,783	1/24/2022	2/2/2022	9	0.017%	0.0015
4000460188	33022	22,124	1/24/2022	2/2/2022	9	0.006%	0.0005
4000460190	33028	170,531	1/24/2022	2/2/2022	9	0.045%	0.0040
4000460191	33029	17,606	1/24/2022	2/2/2022	9	0.005%	0.0004
4000460192	33030	624,124	1/24/2022	2/2/2022	9	0.165%	0.0148
4000460195	33034	2,892	1/24/2022	2/2/2022	9	0.001%	0.0001
4000460198	33039	9,120	1/24/2022	2/2/2022	9	0.002%	0.0002
4000460201	33042	49,473	1/24/2022	2/2/2022	9	0.013%	0.0012
4000460205	33049	6,949	1/24/2022	2/2/2022	9	0.002%	0.0002
4000460207	33052	17,550	1/24/2022	2/2/2022	9	0.005%	0.0004
4000460210	33055	95,389	1/24/2022	2/2/2022	9	0.025%	0.0023
4000460211	33056	4,284	1/24/2022	2/2/2022	9	0.001%	0.0001
4000460214	33059	29,508	1/24/2022	2/2/2022	9	0.008%	0.0007
4000460215	33060	11,811	1/24/2022	2/2/2022	9	0.003%	0.0003
4000460217	33063	61,791	1/24/2022	2/2/2022	9	0.016%	0.0015
4000460219	33065	11,765	1/24/2022	2/2/2022	9	0.003%	0.0003
4000460250	11260	2,864	1/25/2022	2/3/2022	9	0.001%	0.0001
4000460251	11372	5,641	1/25/2022	2/3/2022	9	0.001%	0.0001
4000460252	11577	1,680	1/25/2022	2/3/2022	9	0.000%	0.0000
4000460255	25131	2,755	1/25/2022	2/3/2022	9	0.001%	0.0001
4000460256	25272	510	1/25/2022	2/3/2022	9	0.000%	0.0000
4000460259	27013	24,943	1/25/2022	2/3/2022	9	0.007%	0.0006
4000460262	27552	22,050	1/25/2022	2/3/2022	9	0.006%	0.0005
4000460264	30475	80,071	1/25/2022	2/3/2022	9	0.021%	0.0019
4000460265	30475	59,743	1/25/2022	2/3/2022	9	0.016%	0.0014
4000460266	30475	62,374	1/25/2022	2/3/2022	9	0.016%	0.0015
4000460267	30475	68,069	1/25/2022	2/3/2022	9	0.018%	0.0016
4000460234	107191	4,531	1/25/2022	2/3/2022	9	0.001%	0.0001
4000460291	13911	50,898	1/26/2022	2/4/2022	9	0.013%	0.0012
4000460298	26643	1,377	1/26/2022	2/4/2022	9	0.000%	0.0000
4000460301	27994	880	1/26/2022	2/4/2022	9	0.000%	0.0000
4000460277	15871	9,413	1/26/2022	2/4/2022	9	0.002%	0.0002
4000460282	142926	5,756	1/26/2022	2/4/2022	9	0.002%	0.0001
4000460584	10630	5,600	1/31/2022	2/9/2022	9	0.001%	0.0001
4000460592	24383	3,760	1/31/2022	2/9/2022	9	0.001%	0.0001
4000460595	25599	5,058	1/31/2022	2/9/2022	9	0.001%	0.0001
4000460596	25659	930	1/31/2022	2/9/2022	9	0.000%	0.0000
4000460564	6396	8,921	1/31/2022	2/9/2022	9	0.002%	0.0002
4000460568	107182	160	1/31/2022	2/9/2022	9	0.000%	0.0000
4000460665	14463	18,231	2/1/2022	2/10/2022	9	0.005%	0.0004
4000460667	27013	24,670	2/1/2022	2/10/2022	9	0.007%	0.0006
4000460670	30475	66,076	2/1/2022	2/10/2022	9	0.017%	0.0016
4000460671	30475	82,008	2/1/2022	2/10/2022	9	0.022%	0.0019
4000460672	30475	56,177	2/1/2022	2/10/2022	9	0.015%	0.0013
4000460674	117331	3,000	2/1/2022	2/10/2022	9	0.001%	0.0001
4000460624	116384	15	2/1/2022	2/10/2022	9	0.000%	0.0000
4000460627	125742	20,320	2/1/2022	2/10/2022	9	0.005%	0.0005
4000460639	141370	13,250	2/1/2022	2/10/2022	9	0.003%	0.0003
4000460646	142164	5,356	2/1/2022	2/10/2022	9	0.001%	0.0001
4000460710	27013	6,868	2/2/2022	2/11/2022	9	0.002%	0.0002
4000460717	32875	2,750	2/2/2022	2/11/2022	9	0.001%	0.0001
4000460676	15871	198	2/2/2022	2/11/2022	9	0.000%	0.0000
4000460680	106674	20,291	2/2/2022	2/11/2022	9	0.005%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460687	126715	10,000	2/2/2022	2/11/2022	9	0.003%	0.0002
4000460688	126928	175	2/2/2022	2/11/2022	9	0.000%	0.0000
4000460692	138747	110	2/2/2022	2/11/2022	9	0.000%	0.0000
4000460695	142926	47,928	2/2/2022	2/11/2022	9	0.013%	0.0011
4000460828	11260	1,061	2/7/2022	2/16/2022	9	0.000%	0.0000
4000460830	11474	16,075	2/7/2022	2/16/2022	9	0.004%	0.0004
4000460832	11577	3,255	2/7/2022	2/16/2022	9	0.001%	0.0001
4000460837	26301	6,441	2/7/2022	2/16/2022	9	0.002%	0.0002
4000460847	32896	525	2/7/2022	2/16/2022	9	0.000%	0.0000
4000460813	103392	76	2/7/2022	2/16/2022	9	0.000%	0.0000
4000460824	144342	3,000	2/7/2022	2/16/2022	9	0.001%	0.0001
4000460880	26604	2,415	2/8/2022	2/17/2022	9	0.001%	0.0001
4000460883	117331	14,936	2/8/2022	2/17/2022	9	0.004%	0.0004
4000460870	142635	15,043	2/8/2022	2/17/2022	9	0.004%	0.0004
4000460872	144270	58,350	2/8/2022	2/17/2022	9	0.015%	0.0014
4000460874	144708	5,638	2/8/2022	2/17/2022	9	0.001%	0.0001
4000460912	27994	2,200	2/9/2022	2/18/2022	9	0.001%	0.0001
4000460917	33924	5,391	2/9/2022	2/18/2022	9	0.001%	0.0001
4000460922	117331	2,327	2/9/2022	2/18/2022	9	0.001%	0.0001
4000460884	10055	11,860	2/9/2022	2/18/2022	9	0.003%	0.0003
4000461059	11305	2,459	2/14/2022	2/23/2022	9	0.001%	0.0001
4000461061	18267	5,342	2/14/2022	2/23/2022	9	0.001%	0.0001
4000461069	26659	15,958	2/14/2022	2/23/2022	9	0.004%	0.0004
4000461048	115761	184	2/14/2022	2/23/2022	9	0.000%	0.0000
4000461050	122630	10,000	2/14/2022	2/23/2022	9	0.003%	0.0002
4000461051	129993	1,500	2/14/2022	2/23/2022	9	0.000%	0.0000
4000461057	143312	16,987	2/14/2022	2/23/2022	9	0.004%	0.0004
4000461080	25623	795	2/15/2022	2/24/2022	9	0.000%	0.0000
4000461084	104872	175	2/15/2022	2/24/2022	9	0.000%	0.0000
4000461085	112588	25,900	2/15/2022	2/24/2022	9	0.007%	0.0006
4000461087	116640	75	2/15/2022	2/24/2022	9	0.000%	0.0000
4000461144	9121	800	2/16/2022	2/25/2022	9	0.000%	0.0000
4000461145	13911	12,480	2/16/2022	2/25/2022	9	0.003%	0.0003
4000461148	25808	1,500	2/16/2022	2/25/2022	9	0.000%	0.0000
4000461149	26639	270	2/16/2022	2/25/2022	9	0.000%	0.0000
4000461102	6396	35,683	2/16/2022	2/25/2022	9	0.009%	0.0008
4000461107	102558	32,274	2/16/2022	2/25/2022	9	0.009%	0.0008
4000461115	111528	500	2/16/2022	2/25/2022	9	0.000%	0.0000
4000461128	138494	3,080	2/16/2022	2/25/2022	9	0.001%	0.0001
4000461129	139030	2,500	2/16/2022	2/25/2022	9	0.001%	0.0001
4000461130	140722	2,000	2/16/2022	2/25/2022	9	0.001%	0.0000
4000461138	143941	995	2/16/2022	2/25/2022	9	0.000%	0.0000
4000461296	11577	2,468	2/22/2022	3/3/2022	9	0.001%	0.0001
4000461299	25173	1,485	2/22/2022	3/3/2022	9	0.000%	0.0000
4000461302	27013	9,660	2/22/2022	3/3/2022	9	0.003%	0.0002
4000461305	27962	556	2/22/2022	3/3/2022	9	0.000%	0.0000
4000461307	32537	6,900	2/22/2022	3/3/2022	9	0.002%	0.0002
4000461268	104872	69	2/22/2022	3/3/2022	9	0.000%	0.0000
4000461281	130362	55	2/22/2022	3/3/2022	9	0.000%	0.0000
4000461355	26639	10,260	2/23/2022	3/4/2022	9	0.003%	0.0002
4000461368	134272	8,130	2/23/2022	3/4/2022	9	0.002%	0.0002
4000461318	32138	111,202	2/23/2022	3/4/2022	9	0.029%	0.0026
4000461320	103990	94	2/23/2022	3/4/2022	9	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461325	121825	57,138	2/23/2022	3/4/2022	9	0.015%	0.0014
4000461330	138494	4,620	2/23/2022	3/4/2022	9	0.001%	0.0001
4000461335	141583	92	2/23/2022	3/4/2022	9	0.000%	0.0000
4000461339	144691	9,430	2/23/2022	3/4/2022	9	0.002%	0.0002
4000461495	8392	12,452	2/28/2022	3/9/2022	9	0.003%	0.0003
4000461498	11260	1,379	2/28/2022	3/9/2022	9	0.000%	0.0000
4000461499	11577	4,095	2/28/2022	3/9/2022	9	0.001%	0.0001
4000461501	17342	5,738	2/28/2022	3/9/2022	9	0.002%	0.0001
4000461502	24999	2,100	2/28/2022	3/9/2022	9	0.001%	0.0000
4000461503	25437	12,225	2/28/2022	3/9/2022	9	0.003%	0.0003
4000461504	25659	1,353	2/28/2022	3/9/2022	9	0.000%	0.0000
4000461506	26363	1,054	2/28/2022	3/9/2022	9	0.000%	0.0000
4000461512	32510	2,945	2/28/2022	3/9/2022	9	0.001%	0.0001
4000461516	106699	7,151	2/28/2022	3/9/2022	9	0.002%	0.0002
4000461518	135537	17,424	2/28/2022	3/9/2022	9	0.005%	0.0004
4000461477	104872	1,275	2/28/2022	3/9/2022	9	0.000%	0.0000
4000461478	108180	10,000	2/28/2022	3/9/2022	9	0.003%	0.0002
4000461481	117975	10,000	2/28/2022	3/9/2022	9	0.003%	0.0002
4000461484	126337	25,500	2/28/2022	3/9/2022	9	0.007%	0.0006
4000461487	129491	5,000	2/28/2022	3/9/2022	9	0.001%	0.0001
4000461488	132507	5,606	2/28/2022	3/9/2022	9	0.001%	0.0001
4000461531	13911	18,695	3/1/2022	3/10/2022	9	0.005%	0.0004
4000461533	26604	895	3/1/2022	3/10/2022	9	0.000%	0.0000
4000461598	30475	57,440	3/2/2022	3/11/2022	9	0.015%	0.0014
4000461546	103392	293	3/2/2022	3/11/2022	9	0.000%	0.0000
4000461550	118807	549	3/2/2022	3/11/2022	9	0.000%	0.0000
4000461551	126715	10,000	3/2/2022	3/11/2022	9	0.003%	0.0002
4000461555	134906	3,900	3/2/2022	3/11/2022	9	0.001%	0.0001
4000461562	141831	11,647	3/2/2022	3/11/2022	9	0.003%	0.0003
4000461569	142787	10,258	3/2/2022	3/11/2022	9	0.003%	0.0002
4000461572	143270	4,500	3/2/2022	3/11/2022	9	0.001%	0.0001
4000461585	144573	4,000	3/2/2022	3/11/2022	9	0.001%	0.0001
4000461704	17342	4,320	3/7/2022	3/16/2022	9	0.001%	0.0001
4000461705	24765	7,914	3/7/2022	3/16/2022	9	0.002%	0.0002
4000461678	102558	57,758	3/7/2022	3/16/2022	9	0.015%	0.0014
4000461679	103392	1,407	3/7/2022	3/16/2022	9	0.000%	0.0000
4000461693	132203	5,000	3/7/2022	3/16/2022	9	0.001%	0.0001
4000461674	101122	5,000	3/7/2022	3/16/2022	9	0.001%	0.0001
4000461725	25437	1,588	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461726	25659	718	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461730	27482	360	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461731	33238	6,668	3/8/2022	3/17/2022	9	0.002%	0.0002
4000461732	33747	372	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461714	106840	39	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461719	129757	47	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461720	141583	79	3/8/2022	3/17/2022	9	0.000%	0.0000
4000461761	134272	226,033	3/9/2022	3/18/2022	9	0.060%	0.0054
4000461736	4502	1,346	3/9/2022	3/18/2022	9	0.000%	0.0000
4000461743	121825	17,141	3/9/2022	3/18/2022	9	0.005%	0.0004
4000461749	142942	13,918	3/9/2022	3/18/2022	9	0.004%	0.0003
4000461750	144047	125	3/9/2022	3/18/2022	9	0.000%	0.0000
4000461762	32962	1,606	3/9/2022	3/18/2022	9	0.000%	0.0000
4000461854	105049	5,000	3/14/2022	3/23/2022	9	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461900	11372	3,526	3/15/2022	3/24/2022	9	0.001%	0.0001
4000461901	11536	2,080	3/15/2022	3/24/2022	9	0.001%	0.0000
4000461906	24765	1,440	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461907	25379	1,723	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461909	25987	2,200	3/15/2022	3/24/2022	9	0.001%	0.0001
4000461910	26297	188	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461912	26604	2,015	3/15/2022	3/24/2022	9	0.001%	0.0000
4000461916	28737	450	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461919	32853	675	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461920	32875	850	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461924	124943	950	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461925	126165	5,683	3/15/2022	3/24/2022	9	0.001%	0.0001
4000461883	104872	224	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461892	140930	837	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461893	141031	1,789	3/15/2022	3/24/2022	9	0.000%	0.0000
4000461874	103925	2,597	3/15/2022	3/24/2022	9	0.001%	0.0001
4000461953	27994	2,805	3/16/2022	3/25/2022	9	0.001%	0.0001
4000461935	142942	1,973	3/16/2022	3/25/2022	9	0.001%	0.0000
4000461940	144898	19,404	3/16/2022	3/25/2022	9	0.005%	0.0005
4000462087	11305	1,686	3/21/2022	3/30/2022	9	0.000%	0.0000
4000462088	13911	6,378	3/21/2022	3/30/2022	9	0.002%	0.0002
4000462089	17342	26,123	3/21/2022	3/30/2022	9	0.007%	0.0006
4000462093	25131	380	3/21/2022	3/30/2022	9	0.000%	0.0000
4000462094	25437	1,200	3/21/2022	3/30/2022	9	0.000%	0.0000
4000462095	25599	18,540	3/21/2022	3/30/2022	9	0.005%	0.0004
4000462100	26356	3,893	3/21/2022	3/30/2022	9	0.001%	0.0001
4000462103	26588	5,380	3/21/2022	3/30/2022	9	0.001%	0.0001
4000462106	26642	6,025	3/21/2022	3/30/2022	9	0.002%	0.0001
4000462109	26659	6,358	3/21/2022	3/30/2022	9	0.002%	0.0002
4000462060	103392	16	3/21/2022	3/30/2022	9	0.000%	0.0000
4000462061	104872	49	3/21/2022	3/30/2022	9	0.000%	0.0000
4000462062	105049	9,565	3/21/2022	3/30/2022	9	0.003%	0.0002
4000462133	26453	960	3/22/2022	3/31/2022	9	0.000%	0.0000
4000462134	28530	28,950	3/22/2022	3/31/2022	9	0.008%	0.0007
4000462120	125742	4,200	3/22/2022	3/31/2022	9	0.001%	0.0001
4000462123	132914	4,169,443	3/22/2022	3/31/2022	9	1.100%	0.0990
4000462158	26639	11,610	3/23/2022	4/1/2022	9	0.003%	0.0003
4000462159	26643	10,005	3/23/2022	4/1/2022	9	0.003%	0.0002
4000462154	144663	82,552	3/23/2022	4/1/2022	9	0.022%	0.0020
4000462140	125852	11,637	3/23/2022	4/1/2022	9	0.003%	0.0003
4000462257	11426	2,582	3/28/2022	4/6/2022	9	0.001%	0.0001
4000462264	25659	2,238	3/28/2022	4/6/2022	9	0.001%	0.0001
4000462265	26016	709	3/28/2022	4/6/2022	9	0.000%	0.0000
4000462271	27493	450	3/28/2022	4/6/2022	9	0.000%	0.0000
4000462277	33747	684	3/28/2022	4/6/2022	9	0.000%	0.0000
4000462243	22798	56,948	3/28/2022	4/6/2022	9	0.015%	0.0014
4000462254	143588	10,798	3/28/2022	4/6/2022	9	0.003%	0.0003
4000462297	8392	18,582	3/29/2022	4/7/2022	9	0.005%	0.0004
4000462304	24259	1,156	3/29/2022	4/7/2022	9	0.000%	0.0000
4000462305	25599	705	3/29/2022	4/7/2022	9	0.000%	0.0000
4000462306	25708	1,593	3/29/2022	4/7/2022	9	0.000%	0.0000
4000462283	11260	1,167	3/29/2022	4/7/2022	9	0.000%	0.0000
4000462381	14463	13,878	3/30/2022	4/8/2022	9	0.004%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462385	26213	1,150	3/30/2022	4/8/2022	9	0.000%	0.0000
4000462389	27162	3,972	3/30/2022	4/8/2022	9	0.001%	0.0001
4000462340	117078	1,000	3/30/2022	4/8/2022	9	0.000%	0.0000
4000462344	125758	10,000	3/30/2022	4/8/2022	9	0.003%	0.0002
4000462349	131493	20,000	3/30/2022	4/8/2022	9	0.005%	0.0005
4000462367	143577	11,638	3/30/2022	4/8/2022	9	0.003%	0.0003
4000462376	145000	1,500	3/30/2022	4/8/2022	9	0.000%	0.0000
4000462590	24383	680	4/4/2022	4/13/2022	9	0.000%	0.0000
4000462558	136045	42,000	4/4/2022	4/13/2022	9	0.011%	0.0010
4000462560	141021	2,700	4/4/2022	4/13/2022	9	0.001%	0.0001
4000462563	141831	11,647	4/4/2022	4/13/2022	9	0.003%	0.0003
4000462599	104872	351	4/5/2022	4/14/2022	9	0.000%	0.0000
4000462600	104872	175	4/5/2022	4/14/2022	9	0.000%	0.0000
4000462602	125193	40,000	4/5/2022	4/14/2022	9	0.011%	0.0009
4000462609	144031	1,500	4/5/2022	4/14/2022	9	0.000%	0.0000
4000462610	144410	2,850	4/5/2022	4/14/2022	9	0.001%	0.0001
4000462765	24113	1,845	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462766	24281	4,188	4/11/2022	4/20/2022	9	0.001%	0.0001
4000462767	24383	8,115	4/11/2022	4/20/2022	9	0.002%	0.0002
4000462768	25708	2,864	4/11/2022	4/20/2022	9	0.001%	0.0001
4000462776	33747	372	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462745	6396	6,804	4/11/2022	4/20/2022	9	0.002%	0.0002
4000462747	103131	120	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462753	126928	121	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462754	140752	1,894	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462744	144767	200	4/11/2022	4/20/2022	9	0.000%	0.0000
4000462792	11577	2,783	4/12/2022	4/21/2022	9	0.001%	0.0001
4000462795	26639	12,825	4/12/2022	4/21/2022	9	0.003%	0.0003
4000462797	27704	1,650	4/12/2022	4/21/2022	9	0.000%	0.0000
4000462799	32808	4,565	4/12/2022	4/21/2022	9	0.001%	0.0001
4000462860	34348	990	4/13/2022	4/22/2022	9	0.000%	0.0000
4000462802	15871	2,264	4/13/2022	4/22/2022	9	0.001%	0.0001
4000462812	113271	7,500	4/13/2022	4/22/2022	9	0.002%	0.0002
4000462818	123447	5,000	4/13/2022	4/22/2022	9	0.001%	0.0001
4000462819	123859	280	4/13/2022	4/22/2022	9	0.000%	0.0000
4000462824	128999	1,000	4/13/2022	4/22/2022	9	0.000%	0.0000
4000462825	129151	1,540	4/13/2022	4/22/2022	9	0.000%	0.0000
4000462848	145032	3,473	4/13/2022	4/22/2022	9	0.001%	0.0001
4000462954	25667	4,800	4/18/2022	4/27/2022	9	0.001%	0.0001
4000462958	32537	1,030	4/18/2022	4/27/2022	9	0.000%	0.0000
4000462961	33747	489	4/18/2022	4/27/2022	9	0.000%	0.0000
4000462952	145067	2,200	4/18/2022	4/27/2022	9	0.001%	0.0001
4000462981	25708	2,247	4/19/2022	4/28/2022	9	0.001%	0.0001
4000462987	33238	840	4/19/2022	4/28/2022	9	0.000%	0.0000
4000462989	126165	11,309	4/19/2022	4/28/2022	9	0.003%	0.0003
4000462976	144247	386,396	4/19/2022	4/28/2022	9	0.102%	0.0092
4000463020	26643	524	4/20/2022	4/29/2022	9	0.000%	0.0000
4000463023	30475	4,650	4/20/2022	4/29/2022	9	0.001%	0.0001
4000463001	126192	25,000	4/20/2022	4/29/2022	9	0.007%	0.0006
4000463170	11260	796	4/25/2022	5/4/2022	9	0.000%	0.0000
4000463177	32538	1,135	4/25/2022	5/4/2022	9	0.000%	0.0000
4000463146	27466	2,883	4/25/2022	5/4/2022	9	0.001%	0.0001
4000463157	139707	1,000	4/25/2022	5/4/2022	9	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463193	11426	2,219	4/26/2022	5/5/2022	9	0.001%	0.0001
4000463198	27013	979	4/26/2022	5/5/2022	9	0.000%	0.0000
4000463206	130375	16,131	4/26/2022	5/5/2022	9	0.004%	0.0004
4000463182	33624	233,825	4/26/2022	5/5/2022	9	0.062%	0.0056
4000463218	126604	5,000	4/27/2022	5/6/2022	9	0.001%	0.0001
4000463426	24383	2,620	5/2/2022	5/11/2022	9	0.001%	0.0001
4000463428	25708	1,015	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463430	26297	945	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463434	26642	2,888	5/2/2022	5/11/2022	9	0.001%	0.0001
4000463436	27013	18,899	5/2/2022	5/11/2022	9	0.005%	0.0004
4000463408	107182	160	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463410	114223	1,104	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463411	115998	540	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463413	117032	93,354	5/2/2022	5/11/2022	9	0.025%	0.0022
4000463417	126809	1,733	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463418	129855	1,727	5/2/2022	5/11/2022	9	0.000%	0.0000
4000463506	13911	16,505	5/3/2022	5/12/2022	9	0.004%	0.0004
4000463510	26323	1,398	5/3/2022	5/12/2022	9	0.000%	0.0000
4000463460	116850	431	5/3/2022	5/12/2022	9	0.000%	0.0000
4000463467	131647	2,338	5/3/2022	5/12/2022	9	0.001%	0.0001
4000463472	141021	2,700	5/3/2022	5/12/2022	9	0.001%	0.0001
4000463484	143270	4,500	5/3/2022	5/12/2022	9	0.001%	0.0001
4000463486	143400	3,000	5/3/2022	5/12/2022	9	0.001%	0.0001
4000463487	143807	1,058	5/3/2022	5/12/2022	9	0.000%	0.0000
4000463489	144015	10,000	5/3/2022	5/12/2022	9	0.003%	0.0002
4000463531	9891	19,397	5/4/2022	5/13/2022	9	0.005%	0.0005
4000463525	143272	13,900	5/4/2022	5/13/2022	9	0.004%	0.0003
4000463638	26362	700	5/9/2022	5/18/2022	9	0.000%	0.0000
4000463639	26639	1,080	5/9/2022	5/18/2022	9	0.000%	0.0000
4000463640	27013	5,236	5/9/2022	5/18/2022	9	0.001%	0.0001
4000463628	6396	300	5/9/2022	5/18/2022	9	0.000%	0.0000
4000463670	25599	2,837	5/10/2022	5/19/2022	9	0.001%	0.0001
4000463647	26604	4,670	5/10/2022	5/19/2022	9	0.001%	0.0001
4000463649	101853	2,758	5/10/2022	5/19/2022	9	0.001%	0.0001
4000463651	108289	84	5/10/2022	5/19/2022	9	0.000%	0.0000
4000463652	112215	2,524	5/10/2022	5/19/2022	9	0.001%	0.0001
4000463662	144519	5,107	5/10/2022	5/19/2022	9	0.001%	0.0001
4000463725	30475	22,915	5/11/2022	5/20/2022	9	0.006%	0.0005
4000463726	30475	33,861	5/11/2022	5/20/2022	9	0.009%	0.0008
4000463729	124628	6,367	5/11/2022	5/20/2022	9	0.002%	0.0002
4000463690	103471	808	5/11/2022	5/20/2022	9	0.000%	0.0000
4000463883	24113	1,910	5/16/2022	5/25/2022	9	0.001%	0.0000
4000463885	24383	4,868	5/16/2022	5/25/2022	9	0.001%	0.0001
4000463896	27013	1,484	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463900	33946	99,267	5/16/2022	5/25/2022	9	0.026%	0.0024
4000463829	101386	2,500	5/16/2022	5/25/2022	9	0.001%	0.0001
4000463831	105049	2,500	5/16/2022	5/25/2022	9	0.001%	0.0001
4000463850	125536	169	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463853	126928	216	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463860	133670	1,000	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463863	138862	60	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463876	145117	1,500	5/16/2022	5/25/2022	9	0.000%	0.0000
4000463878	116971	3,000	5/16/2022	5/25/2022	9	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463918	144519	23,400	5/17/2022	5/26/2022	9	0.006%	0.0006
4000463957	26604	1,775	5/18/2022	5/27/2022	9	0.000%	0.0000
4000463968	32875	600	5/18/2022	5/27/2022	9	0.000%	0.0000
4000463973	137825	934	5/18/2022	5/27/2022	9	0.000%	0.0000
4000463926	9986	272,215	5/18/2022	5/27/2022	9	0.072%	0.0065
4000463929	35151	6,750	5/18/2022	5/27/2022	9	0.002%	0.0002
4000463943	143433	4,406	5/18/2022	5/27/2022	9	0.001%	0.0001
4000463945	144270	392	5/18/2022	5/27/2022	9	0.000%	0.0000
4000463946	144480	58,100	5/18/2022	5/27/2022	9	0.015%	0.0014
4000464089	5673	40,800	5/23/2022	6/1/2022	9	0.011%	0.0010
4000464091	18267	735	5/23/2022	6/1/2022	9	0.000%	0.0000
4000464068	105195	2,561	5/23/2022	6/1/2022	9	0.001%	0.0001
4000464071	115761	46	5/23/2022	6/1/2022	9	0.000%	0.0000
4000464072	116051	3,717	5/23/2022	6/1/2022	9	0.001%	0.0001
4000464073	116384	277	5/23/2022	6/1/2022	9	0.000%	0.0000
4000464075	119139	11,723	5/23/2022	6/1/2022	9	0.003%	0.0003
4000464079	131493	5,000	5/23/2022	6/1/2022	9	0.001%	0.0001
4000464082	140979	7,500	5/23/2022	6/1/2022	9	0.002%	0.0002
4000464115	25131	3,325	5/24/2022	6/2/2022	9	0.001%	0.0001
4000464116	25659	7,575	5/24/2022	6/2/2022	9	0.002%	0.0002
4000464118	26016	1,331	5/24/2022	6/2/2022	9	0.000%	0.0000
4000464124	27994	6,710	5/24/2022	6/2/2022	9	0.002%	0.0002
4000464125	28084	9,785	5/24/2022	6/2/2022	9	0.003%	0.0002
4000464127	28737	14,300	5/24/2022	6/2/2022	9	0.004%	0.0003
4000464133	124943	665	5/24/2022	6/2/2022	9	0.000%	0.0000
4000464096	103392	54	5/24/2022	6/2/2022	9	0.000%	0.0000
4000464108	144530	3,400	5/24/2022	6/2/2022	9	0.001%	0.0001
4000464162	11426	2,368	5/25/2022	6/3/2022	9	0.001%	0.0001
4000464167	25905	2,900	5/25/2022	6/3/2022	9	0.001%	0.0001
4000464170	26604	1,295	5/25/2022	6/3/2022	9	0.000%	0.0000
4000464177	33770	4,625	5/25/2022	6/3/2022	9	0.001%	0.0001
4000464178	35012	930	5/25/2022	6/3/2022	9	0.000%	0.0000
4000464137	15871	1,343	5/25/2022	6/3/2022	9	0.000%	0.0000
4000464144	121825	29,997	5/25/2022	6/3/2022	9	0.008%	0.0007
4000464145	125742	4,820	5/25/2022	6/3/2022	9	0.001%	0.0001
4000464150	142870	18,196	5/25/2022	6/3/2022	9	0.005%	0.0004
4000464152	143880	1,800	5/25/2022	6/3/2022	9	0.000%	0.0000
4000464157	144955	2,019	5/25/2022	6/3/2022	9	0.001%	0.0000
4000464342	8998	841	5/31/2022	6/9/2022	9	0.000%	0.0000
4000464348	25272	870	5/31/2022	6/9/2022	9	0.000%	0.0000
4000464355	26361	19,948	5/31/2022	6/9/2022	9	0.005%	0.0005
4000464324	118989	2,307	5/31/2022	6/9/2022	9	0.001%	0.0001
4000464332	138600	4,550	5/31/2022	6/9/2022	9	0.001%	0.0001
4000464405	26643	3,324	6/1/2022	6/10/2022	9	0.001%	0.0001
4000464408	27162	7,600	6/1/2022	6/10/2022	9	0.002%	0.0002
4000464376	101853	3,128	6/1/2022	6/10/2022	9	0.001%	0.0001
4000464556	11305	569	6/6/2022	6/15/2022	9	0.000%	0.0000
4000464558	17342	14,040	6/6/2022	6/15/2022	9	0.004%	0.0003
4000464560	25131	1,615	6/6/2022	6/15/2022	9	0.000%	0.0000
4000464564	26363	1,518	6/6/2022	6/15/2022	9	0.000%	0.0000
4000464567	26659	38,211	6/6/2022	6/15/2022	9	0.010%	0.0009
4000464569	27981	2,290	6/6/2022	6/15/2022	9	0.001%	0.0001
4000464571	34173	11,126	6/6/2022	6/15/2022	9	0.003%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464592	10384	7,350	6/7/2022	6/16/2022	9	0.002%	0.0002
4000464593	11054	11,566	6/7/2022	6/16/2022	9	0.003%	0.0003
4000464595	25599	1,655	6/7/2022	6/16/2022	9	0.000%	0.0000
4000464599	27704	700	6/7/2022	6/16/2022	9	0.000%	0.0000
4000464603	28737	400	6/7/2022	6/16/2022	9	0.000%	0.0000
4000464606	32808	3,355	6/7/2022	6/16/2022	9	0.001%	0.0001
4000464607	32853	360	6/7/2022	6/16/2022	9	0.000%	0.0000
4000464588	144581	1,208	6/7/2022	6/16/2022	9	0.000%	0.0000
4000464772	26338	946	6/13/2022	6/22/2022	9	0.000%	0.0000
4000464773	26361	12,197	6/13/2022	6/22/2022	9	0.003%	0.0003
4000464777	26655	693	6/13/2022	6/22/2022	9	0.000%	0.0000
4000464782	34341	165	6/13/2022	6/22/2022	9	0.000%	0.0000
4000464783	109948	4,244	6/13/2022	6/22/2022	9	0.001%	0.0001
4000464786	126775	594	6/13/2022	6/22/2022	9	0.000%	0.0000
4000464808	11536	5,970	6/14/2022	6/23/2022	9	0.002%	0.0001
4000464816	32808	2,090	6/14/2022	6/23/2022	9	0.001%	0.0000
4000464791	106699	2,926	6/14/2022	6/23/2022	9	0.001%	0.0001
4000464793	116051	592	6/14/2022	6/23/2022	9	0.000%	0.0000
4000464795	125742	4,482	6/14/2022	6/23/2022	9	0.001%	0.0001
4000464802	143189	13,236	6/14/2022	6/23/2022	9	0.003%	0.0003
4000464846	25905	3,900	6/15/2022	6/24/2022	9	0.001%	0.0001
4000464851	26639	11,273	6/15/2022	6/24/2022	9	0.003%	0.0003
4000464853	27013	26,563	6/15/2022	6/24/2022	9	0.007%	0.0006
4000464864	117331	1,900	6/15/2022	6/24/2022	9	0.001%	0.0000
4000464820	24765	35,205	6/15/2022	6/24/2022	9	0.009%	0.0008
4000464822	103008	633	6/15/2022	6/24/2022	9	0.000%	0.0000
4000464826	113563	5,672	6/15/2022	6/24/2022	9	0.001%	0.0001
4000464834	135300	2,000	6/15/2022	6/24/2022	9	0.001%	0.0000
4000464995	34658	7,500	6/20/2022	6/29/2022	9	0.002%	0.0002
4000464986	131557	1,000	6/20/2022	6/29/2022	9	0.000%	0.0000
4000465015	25905	5,200	6/21/2022	6/30/2022	9	0.001%	0.0001
4000465017	27013	506	6/21/2022	6/30/2022	9	0.000%	0.0000
4000464999	4502	2,692	6/21/2022	6/30/2022	9	0.001%	0.0001
4000465001	103008	62	6/21/2022	6/30/2022	9	0.000%	0.0000
4000465003	103405	6,500	6/21/2022	6/30/2022	9	0.002%	0.0002
4000465036	11536	6,550	6/22/2022	7/1/2022	9	0.002%	0.0002
4000465041	26604	14,430	6/22/2022	7/1/2022	9	0.004%	0.0003
4000465055	117331	21,800	6/22/2022	7/1/2022	9	0.006%	0.0005
4000465202	10384	2,800	6/27/2022	7/6/2022	9	0.001%	0.0001
4000465205	14060	1,023	6/27/2022	7/6/2022	9	0.000%	0.0000
4000465207	14949	2,089	6/27/2022	7/6/2022	9	0.001%	0.0000
4000465208	24113	5,478	6/27/2022	7/6/2022	9	0.001%	0.0001
4000465213	24825	994	6/27/2022	7/6/2022	9	0.000%	0.0000
4000465224	26659	57,411	6/27/2022	7/6/2022	9	0.015%	0.0014
4000465228	34658	2,500	6/27/2022	7/6/2022	9	0.001%	0.0001
4000465183	108208	100,000	6/27/2022	7/6/2022	9	0.026%	0.0024
4000465185	118807	903	6/27/2022	7/6/2022	9	0.000%	0.0000
4000465190	127985	1,000	6/27/2022	7/6/2022	9	0.000%	0.0000
4000465193	141802	69,988	6/27/2022	7/6/2022	9	0.018%	0.0017
4000465197	145175	1,039	6/27/2022	7/6/2022	9	0.000%	0.0000
4000465255	11474	1,075	6/28/2022	7/7/2022	9	0.000%	0.0000
4000465259	24385	5,346	6/28/2022	7/7/2022	9	0.001%	0.0001
4000465262	26297	7,058	6/28/2022	7/7/2022	9	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465267	26679	16,375	6/28/2022	7/7/2022	9	0.004%	0.0004
4000465271	34658	2,000	6/28/2022	7/7/2022	9	0.001%	0.0000
4000465233	19534	35,500	6/28/2022	7/7/2022	9	0.009%	0.0008
4000465235	103392	334	6/28/2022	7/7/2022	9	0.000%	0.0000
4000465238	107047	214	6/28/2022	7/7/2022	9	0.000%	0.0000
4000465241	116384	56	6/28/2022	7/7/2022	9	0.000%	0.0000
4000465251	143340	161,526	6/28/2022	7/7/2022	9	0.043%	0.0038
4000465290	25808	4,620	6/29/2022	7/8/2022	9	0.001%	0.0001
4000465283	143340	95,494	6/29/2022	7/8/2022	9	0.025%	0.0023
4000465286	145023	5,000	6/29/2022	7/8/2022	9	0.001%	0.0001
4000465483	11577	840	7/5/2022	7/14/2022	9	0.000%	0.0000
4000465485	24259	771	7/5/2022	7/14/2022	9	0.000%	0.0000
4000465490	32808	880	7/5/2022	7/14/2022	9	0.000%	0.0000
4000465491	32853	360	7/5/2022	7/14/2022	9	0.000%	0.0000
4000465472	105195	14,319	7/5/2022	7/14/2022	9	0.004%	0.0003
4000465649	11305	4,813	7/11/2022	7/20/2022	9	0.001%	0.0001
4000465653	26659	748	7/11/2022	7/20/2022	9	0.000%	0.0000
4000465659	130375	3,806	7/11/2022	7/20/2022	9	0.001%	0.0001
4000465630	25147	26,712	7/11/2022	7/20/2022	9	0.007%	0.0006
4000465631	26588	1,545	7/11/2022	7/20/2022	9	0.000%	0.0000
4000465633	103471	71	7/11/2022	7/20/2022	9	0.000%	0.0000
4000465636	112215	2,580	7/11/2022	7/20/2022	9	0.001%	0.0001
4000465646	145055	6,796	7/11/2022	7/20/2022	9	0.002%	0.0002
4000465710	9145	20,950	7/12/2022	7/21/2022	9	0.006%	0.0005
4000465715	111669	60	7/12/2022	7/21/2022	9	0.000%	0.0000
4000465724	144663	171,662	7/12/2022	7/21/2022	9	0.045%	0.0041
4000465759	8392	12,025	7/13/2022	7/22/2022	9	0.003%	0.0003
4000465760	24211	1,850	7/13/2022	7/22/2022	9	0.000%	0.0000
4000465766	33770	3,852	7/13/2022	7/22/2022	9	0.001%	0.0001
4000465736	13911	16,380	7/13/2022	7/22/2022	9	0.004%	0.0004
4000465754	144270	359	7/13/2022	7/22/2022	9	0.000%	0.0000
4000465886	26639	4,658	7/18/2022	7/27/2022	9	0.001%	0.0001
4000465868	103392	16	7/18/2022	7/27/2022	9	0.000%	0.0000
4000465873	138153	6,000	7/18/2022	7/27/2022	9	0.002%	0.0001
4000465880	145152	41,199	7/18/2022	7/27/2022	9	0.011%	0.0010
4000465909	26642	3,769	7/19/2022	7/28/2022	9	0.001%	0.0001
4000465913	30475	3,122	7/19/2022	7/28/2022	9	0.001%	0.0001
4000465902	144581	3,624	7/19/2022	7/28/2022	9	0.001%	0.0001
4000465903	145235	500	7/19/2022	7/28/2022	9	0.000%	0.0000
4000465968	25395	750	7/20/2022	7/29/2022	9	0.000%	0.0000
4000465969	26323	1,075	7/20/2022	7/29/2022	9	0.000%	0.0000
4000465972	27068	3,534	7/20/2022	7/29/2022	9	0.001%	0.0001
4000465973	27962	5,186	7/20/2022	7/29/2022	9	0.001%	0.0001
4000465957	143477	400	7/20/2022	7/29/2022	9	0.000%	0.0000
4000465962	144519	18,307	7/20/2022	7/29/2022	9	0.005%	0.0004
4000466098	24825	7,008	7/25/2022	8/3/2022	9	0.002%	0.0002
4000466107	34531	102,713	7/25/2022	8/3/2022	9	0.027%	0.0024
4000466088	104154	88	7/25/2022	8/3/2022	9	0.000%	0.0000
4000466092	141583	158	7/25/2022	8/3/2022	9	0.000%	0.0000
4000466095	143463	28,980	7/25/2022	8/3/2022	9	0.008%	0.0007
4000466160	11372	471	7/26/2022	8/4/2022	9	0.000%	0.0000
4000466113	116718	4,529	7/26/2022	8/4/2022	9	0.001%	0.0001
4000466114	116850	431	7/26/2022	8/4/2022	9	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466139	143929	22,666	7/26/2022	8/4/2022	9	0.006%	0.0005
4000466145	144530	5,151	7/26/2022	8/4/2022	9	0.001%	0.0001
4000466148	144773	625	7/26/2022	8/4/2022	9	0.000%	0.0000
4000466189	24999	739	7/27/2022	8/5/2022	9	0.000%	0.0000
4000466193	27068	912	7/27/2022	8/5/2022	9	0.000%	0.0000
4000466166	2061	89,899	7/27/2022	8/5/2022	9	0.024%	0.0021
4000466178	143477	1,240	7/27/2022	8/5/2022	9	0.000%	0.0000
4000466369	11260	2,599	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466376	26016	3,399	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466380	26577	3,750	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466345	103392	15	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466347	116384	131	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466350	138862	100	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466353	141025	18,000	8/1/2022	8/10/2022	9	0.005%	0.0004
4000466356	143619	37,358	8/1/2022	8/10/2022	9	0.010%	0.0009
4000466363	145067	2,200	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466364	145181	1,200	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466394	32923	6	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466418	33129	3,614	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466421	33147	52	8/1/2022	8/10/2022	9	0.000%	0.0000
4000466422	33152	5,074	8/1/2022	8/10/2022	9	0.001%	0.0001
4000466431	9673	400	8/2/2022	8/11/2022	9	0.000%	0.0000
4000466432	25908	10,750	8/2/2022	8/11/2022	9	0.003%	0.0003
4000466437	30475	11,903	8/2/2022	8/11/2022	9	0.003%	0.0003
4000466473	34658	5,000	8/3/2022	8/12/2022	9	0.001%	0.0001
4000466444	103913	113	8/3/2022	8/12/2022	9	0.000%	0.0000
4000466453	125349	765	8/3/2022	8/12/2022	9	0.000%	0.0000
4000466460	143270	428	8/3/2022	8/12/2022	9	0.000%	0.0000
4000466462	144567	4,159	8/3/2022	8/12/2022	9	0.001%	0.0001
4000466463	144886	6,320	8/3/2022	8/12/2022	9	0.002%	0.0002
4000466475	32932	12,826	8/3/2022	8/12/2022	9	0.003%	0.0003
4000466477	32942	2,514	8/3/2022	8/12/2022	9	0.001%	0.0001
4000466478	32959	2,364	8/3/2022	8/12/2022	9	0.001%	0.0001
4000466481	32982	17,573	8/3/2022	8/12/2022	9	0.005%	0.0004
4000466483	32991	2,059	8/3/2022	8/12/2022	9	0.001%	0.0000
4000466486	33110	74,092	8/3/2022	8/12/2022	9	0.020%	0.0018
4000466438	103927	4,150	8/3/2022	8/12/2022	9	0.001%	0.0001
4000466596	24385	196	8/8/2022	8/17/2022	9	0.000%	0.0000
4000466599	25599	5,393	8/8/2022	8/17/2022	9	0.001%	0.0001
4000466604	26604	1,135	8/8/2022	8/17/2022	9	0.000%	0.0000
4000466605	26639	540	8/8/2022	8/17/2022	9	0.000%	0.0000
4000466606	26642	3,601	8/8/2022	8/17/2022	9	0.001%	0.0001
4000466580	103392	18	8/8/2022	8/17/2022	9	0.000%	0.0000
4000466586	142942	5,961	8/8/2022	8/17/2022	9	0.002%	0.0001
4000466638	11536	6,435	8/9/2022	8/18/2022	9	0.002%	0.0002
4000466641	130375	14,580	8/9/2022	8/18/2022	9	0.004%	0.0003
4000466683	30475	35,655	8/10/2022	8/19/2022	9	0.009%	0.0008
4000466684	30475	37,461	8/10/2022	8/19/2022	9	0.010%	0.0009
4000466685	30475	39,307	8/10/2022	8/19/2022	9	0.010%	0.0009
4000466686	30475	43,566	8/10/2022	8/19/2022	9	0.011%	0.0010
4000466687	30475	46,397	8/10/2022	8/19/2022	9	0.012%	0.0011
4000466688	32808	1,650	8/10/2022	8/19/2022	9	0.000%	0.0000
4000466690	34341	7,700	8/10/2022	8/19/2022	9	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466644	15871	7,817	8/10/2022	8/19/2022	9	0.002%	0.0002
4000466647	108122	5,000	8/10/2022	8/19/2022	9	0.001%	0.0001
4000466655	126248	100	8/10/2022	8/19/2022	9	0.000%	0.0000
4000466700	33055	97,945	8/10/2022	8/19/2022	9	0.026%	0.0023
4000466701	33057	1,122	8/10/2022	8/19/2022	9	0.000%	0.0000
4000466704	33065	11,938	8/10/2022	8/19/2022	9	0.003%	0.0003
4000466708	33088	5,122	8/10/2022	8/19/2022	9	0.001%	0.0001
4000466710	33093	286	8/10/2022	8/19/2022	9	0.000%	0.0000
4000466712	33113	29,079	8/10/2022	8/19/2022	9	0.008%	0.0007
4000466714	33130	391	8/10/2022	8/19/2022	9	0.000%	0.0000
4000466836	11260	5,729	8/15/2022	8/24/2022	9	0.002%	0.0001
4000466838	17342	6,345	8/15/2022	8/24/2022	9	0.002%	0.0002
4000466853	130375	26,818	8/15/2022	8/24/2022	9	0.007%	0.0006
4000466822	9145	3,450	8/15/2022	8/24/2022	9	0.001%	0.0001
4000466894	34393	9,600	8/16/2022	8/25/2022	9	0.003%	0.0002
4000466879	141826	20,329	8/16/2022	8/25/2022	9	0.005%	0.0005
4000466884	145239	11,943	8/16/2022	8/25/2022	9	0.003%	0.0003
4000466928	26639	19,508	8/17/2022	8/26/2022	9	0.005%	0.0005
4000466930	26643	1,956	8/17/2022	8/26/2022	9	0.001%	0.0000
4000466932	26674	1,120	8/17/2022	8/26/2022	9	0.000%	0.0000
4000466934	27068	2,793	8/17/2022	8/26/2022	9	0.001%	0.0001
4000467084	26639	675	8/22/2022	8/31/2022	9	0.000%	0.0000
4000467063	103392	479	8/22/2022	8/31/2022	9	0.000%	0.0000
4000467064	103818	50	8/22/2022	8/31/2022	9	0.000%	0.0000
4000467069	118807	1,319	8/22/2022	8/31/2022	9	0.000%	0.0000
4000467078	142942	7,014	8/22/2022	8/31/2022	9	0.002%	0.0002
4000467104	24825	895	8/23/2022	9/1/2022	9	0.000%	0.0000
4000467107	27962	2,394	8/23/2022	9/1/2022	9	0.001%	0.0001
4000467094	142926	125	8/23/2022	9/1/2022	9	0.000%	0.0000
4000467111	15871	5,233	8/24/2022	9/2/2022	9	0.001%	0.0001
4000467128	143072	2,111	8/24/2022	9/2/2022	9	0.001%	0.0001
4000467130	143457	10,000	8/24/2022	9/2/2022	9	0.003%	0.0002
4000467287	105195	6,052	8/29/2022	9/7/2022	9	0.002%	0.0001
4000467267	103392	15	8/29/2022	9/7/2022	9	0.000%	0.0000
4000467268	105195	10,799	8/29/2022	9/7/2022	9	0.003%	0.0003
4000467269	116384	16	8/29/2022	9/7/2022	9	0.000%	0.0000
4000467317	11372	58,766	8/30/2022	9/8/2022	9	0.015%	0.0014
4000467318	13911	124,343	8/30/2022	9/8/2022	9	0.033%	0.0030
4000467322	25708	2,076	8/30/2022	9/8/2022	9	0.001%	0.0000
4000467326	32808	1,100	8/30/2022	9/8/2022	9	0.000%	0.0000
4000467291	103114	27	8/30/2022	9/8/2022	9	0.000%	0.0000
4000467300	129891	19,150	8/30/2022	9/8/2022	9	0.005%	0.0005
4000467303	141610	733,840	8/30/2022	9/8/2022	9	0.194%	0.0174
4000467308	143622	5,338	8/30/2022	9/8/2022	9	0.001%	0.0001
4000467312	144530	82,366	8/30/2022	9/8/2022	9	0.022%	0.0020
4000467313	144581	1,933	8/30/2022	9/8/2022	9	0.001%	0.0000
4000467374	25659	23,388	8/31/2022	9/9/2022	9	0.006%	0.0006
4000467377	26213	8,694	8/31/2022	9/9/2022	9	0.002%	0.0002
4000467379	26577	700	8/31/2022	9/9/2022	9	0.000%	0.0000
4000467381	27013	13,564	8/31/2022	9/9/2022	9	0.004%	0.0003
4000467383	28084	21,660	8/31/2022	9/9/2022	9	0.006%	0.0005
4000467338	25147	93,911	8/31/2022	9/9/2022	9	0.025%	0.0022
4000467339	28084	950	8/31/2022	9/9/2022	9	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467345	110291	3,135	8/31/2022	9/9/2022	9	0.001%	0.0001
4000467347	113967	4,809	8/31/2022	9/9/2022	9	0.001%	0.0001
4000467349	117078	2,500	8/31/2022	9/9/2022	9	0.001%	0.0001
4000467352	126047	12,573	8/31/2022	9/9/2022	9	0.003%	0.0003
4000467360	142615	29,568	8/31/2022	9/9/2022	9	0.008%	0.0007
4000467366	144638	10,000	8/31/2022	9/9/2022	9	0.003%	0.0002
4000467542	103392	929	9/6/2022	9/15/2022	9	0.000%	0.0000
4000467547	129859	1,959,816	9/6/2022	9/15/2022	9	0.517%	0.0465
4000467548	142164	5,356	9/6/2022	9/15/2022	9	0.001%	0.0001
4000467541	126796	9,079	9/6/2022	9/15/2022	9	0.002%	0.0002
4000467577	144084	9,288	9/7/2022	9/16/2022	9	0.002%	0.0002
4000467700	11372	23,178	9/13/2022	9/22/2022	9	0.006%	0.0006
4000467708	27962	627	9/13/2022	9/22/2022	9	0.000%	0.0000
4000467692	32874	12,291	9/13/2022	9/22/2022	9	0.003%	0.0003
4000467689	130231	35,000	9/13/2022	9/22/2022	9	0.009%	0.0008
4000467757	25908	26,813	9/14/2022	9/23/2022	9	0.007%	0.0006
4000467762	27013	1,743	9/14/2022	9/23/2022	9	0.000%	0.0000
4000467729	126599	5,000	9/14/2022	9/23/2022	9	0.001%	0.0001
4000467732	135388	2,500	9/14/2022	9/23/2022	9	0.001%	0.0001
4000467738	143577	3,152	9/14/2022	9/23/2022	9	0.001%	0.0001
4000467743	145251	2,685	9/14/2022	9/23/2022	9	0.001%	0.0001
4000467909	28474	2,703	9/19/2022	9/28/2022	9	0.001%	0.0001
4000467890	103392	16	9/19/2022	9/28/2022	9	0.000%	0.0000
4000467895	142942	2,640	9/19/2022	9/28/2022	9	0.001%	0.0001
4000467898	143619	31,738	9/19/2022	9/28/2022	9	0.008%	0.0008
4000467933	11372	2,333	9/20/2022	9/29/2022	9	0.001%	0.0001
4000467934	11536	29,720	9/20/2022	9/29/2022	9	0.008%	0.0007
4000467937	24259	5,974	9/20/2022	9/29/2022	9	0.002%	0.0001
4000467944	26643	999	9/20/2022	9/29/2022	9	0.000%	0.0000
4000467946	32896	1,953	9/20/2022	9/29/2022	9	0.001%	0.0000
4000467921	126928	671	9/20/2022	9/29/2022	9	0.000%	0.0000
4000467978	34531	250,308	9/21/2022	9/30/2022	9	0.066%	0.0059
4000467981	104725	2,397	9/21/2022	9/30/2022	9	0.001%	0.0001
4000467952	15871	3,760	9/21/2022	9/30/2022	9	0.001%	0.0001
4000468111	143132	2,500	9/26/2022	10/5/2022	9	0.001%	0.0001
4000468155	25905	700	9/27/2022	10/6/2022	9	0.000%	0.0000
4000468156	26207	1,100	9/27/2022	10/6/2022	9	0.000%	0.0000
4000468158	26639	1,620	9/27/2022	10/6/2022	9	0.000%	0.0000
4000468163	126165	12,629	9/27/2022	10/6/2022	9	0.003%	0.0003
4000468132	22798	28,948	9/27/2022	10/6/2022	9	0.008%	0.0007
4000468135	110291	14,460	9/27/2022	10/6/2022	9	0.004%	0.0003
4000468167	32978	1,403	9/27/2022	10/6/2022	9	0.000%	0.0000
4000468169	32998	24,572	9/27/2022	10/6/2022	9	0.006%	0.0006
4000468176	33072	58,572	9/27/2022	10/6/2022	9	0.015%	0.0014
4000468187	33119	5,965	9/27/2022	10/6/2022	9	0.002%	0.0001
4000468189	33131	42,059	9/27/2022	10/6/2022	9	0.011%	0.0010
4000468253	27962	684	9/28/2022	10/7/2022	9	0.000%	0.0000
4000468194	6396	35,683	9/28/2022	10/7/2022	9	0.009%	0.0008
4000468196	15871	2,178	9/28/2022	10/7/2022	9	0.001%	0.0001
4000468202	34888	167	9/28/2022	10/7/2022	9	0.000%	0.0000
4000468203	101386	2,000	9/28/2022	10/7/2022	9	0.001%	0.0000
4000468205	102473	650	9/28/2022	10/7/2022	9	0.000%	0.0000
4000468451	24385	10,326	10/3/2022	10/12/2022	9	0.003%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468456	26338	1,664	10/3/2022	10/12/2022	9	0.000%	0.0000
4000468461	26659	35,282	10/3/2022	10/12/2022	9	0.009%	0.0008
4000468467	34658	2,000	10/3/2022	10/12/2022	9	0.001%	0.0000
4000468428	100335	15,428	10/3/2022	10/12/2022	9	0.004%	0.0004
4000468430	110291	2,652	10/3/2022	10/12/2022	9	0.001%	0.0001
4000468432	138862	50	10/3/2022	10/12/2022	9	0.000%	0.0000
4000468434	143011	26,141	10/3/2022	10/12/2022	9	0.007%	0.0006
4000468435	143072	81,733	10/3/2022	10/12/2022	9	0.022%	0.0019
4000468440	145059	2,000	10/3/2022	10/12/2022	9	0.001%	0.0000
4000468469	110195	33,844	10/4/2022	10/13/2022	9	0.009%	0.0008
4000468487	105215	220,122	10/5/2022	10/14/2022	9	0.058%	0.0052
4000468640	9121	3,100	10/11/2022	10/20/2022	9	0.001%	0.0001
4000468643	11536	7,100	10/11/2022	10/20/2022	9	0.002%	0.0002
4000468644	18267	6,776	10/11/2022	10/20/2022	9	0.002%	0.0002
4000468651	25809	3,486	10/11/2022	10/20/2022	9	0.001%	0.0001
4000468655	26644	7,290	10/11/2022	10/20/2022	9	0.002%	0.0002
4000468657	26679	11,875	10/11/2022	10/20/2022	9	0.003%	0.0003
4000468626	118807	26	10/11/2022	10/20/2022	9	0.000%	0.0000
4000468629	141203	69,434	10/11/2022	10/20/2022	9	0.018%	0.0016
4000468632	143569	28,800	10/11/2022	10/20/2022	9	0.008%	0.0007
4000468635	144530	73,201	10/11/2022	10/20/2022	9	0.019%	0.0017
4000468615	126796	200	10/11/2022	10/20/2022	9	0.000%	0.0000
4000468727	26381	5,400	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468729	27013	3,111	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468730	27068	570	10/12/2022	10/21/2022	9	0.000%	0.0000
4000468736	33956	896	10/12/2022	10/21/2022	9	0.000%	0.0000
4000468738	34972	22,565	10/12/2022	10/21/2022	9	0.006%	0.0005
4000468675	15871	4,909	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468682	107786	1,100	10/12/2022	10/21/2022	9	0.000%	0.0000
4000468684	109222	3,400	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468685	109457	15,000	10/12/2022	10/21/2022	9	0.004%	0.0004
4000468686	109523	12,500	10/12/2022	10/21/2022	9	0.003%	0.0003
4000468695	121800	1,000	10/12/2022	10/21/2022	9	0.000%	0.0000
4000468697	125742	3,320	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468716	145251	2,158	10/12/2022	10/21/2022	9	0.001%	0.0001
4000468852	32869	10,000	10/17/2022	10/26/2022	9	0.003%	0.0002
4000468853	103392	17	10/17/2022	10/26/2022	9	0.000%	0.0000
4000468854	107313	12,000	10/17/2022	10/26/2022	9	0.003%	0.0003
4000468859	118807	211	10/17/2022	10/26/2022	9	0.000%	0.0000
4000468928	25987	800	10/18/2022	10/27/2022	9	0.000%	0.0000
4000468930	26604	3,790	10/18/2022	10/27/2022	9	0.001%	0.0001
4000468931	27962	855	10/18/2022	10/27/2022	9	0.000%	0.0000
4000468932	32896	1,900	10/18/2022	10/27/2022	9	0.001%	0.0000
4000468904	103639	208	10/18/2022	10/27/2022	9	0.000%	0.0000
4000468908	108083	50	10/18/2022	10/27/2022	9	0.000%	0.0000
4000468895	109293	3,750	10/18/2022	10/27/2022	9	0.001%	0.0001
4000468897	129764	68,974	10/18/2022	10/27/2022	9	0.018%	0.0016
4000468954	24825	970	10/19/2022	10/28/2022	9	0.000%	0.0000
4000468936	4502	132,116	10/19/2022	10/28/2022	9	0.035%	0.0031
4000468938	15871	5,412	10/19/2022	10/28/2022	9	0.001%	0.0001
4000468943	125742	14,552	10/19/2022	10/28/2022	9	0.004%	0.0003
4000468947	143573	4,540	10/19/2022	10/28/2022	9	0.001%	0.0001
4000468971	32927	137,050	10/19/2022	10/28/2022	9	0.036%	0.0033

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468976	32948	2,275	10/19/2022	10/28/2022	9	0.001%	0.0001
4000468986	32980	3,726	10/19/2022	10/28/2022	9	0.001%	0.0001
4000468987	32981	25,517	10/19/2022	10/28/2022	9	0.007%	0.0006
4000468988	32983	44,140	10/19/2022	10/28/2022	9	0.012%	0.0010
4000469006	33045	31,457	10/19/2022	10/28/2022	9	0.008%	0.0007
4000469008	33056	2,229	10/19/2022	10/28/2022	9	0.001%	0.0001
4000469010	33063	30,884	10/19/2022	10/28/2022	9	0.008%	0.0007
4000469017	33079	25,390	10/19/2022	10/28/2022	9	0.007%	0.0006
4000469163	105195	2,088	10/24/2022	11/2/2022	9	0.001%	0.0000
4000469164	106699	12,713	10/24/2022	11/2/2022	9	0.003%	0.0003
4000469135	15871	556	10/24/2022	11/2/2022	9	0.000%	0.0000
4000469137	104154	88	10/24/2022	11/2/2022	9	0.000%	0.0000
4000469138	107182	160	10/24/2022	11/2/2022	9	0.000%	0.0000
4000469150	143072	1,294	10/24/2022	11/2/2022	9	0.000%	0.0000
4000469152	143901	350	10/24/2022	11/2/2022	9	0.000%	0.0000
4000469190	11260	19,521	10/25/2022	11/3/2022	9	0.005%	0.0005
4000469198	25987	2,000	10/25/2022	11/3/2022	9	0.001%	0.0000
4000469171	110291	15,213	10/25/2022	11/3/2022	9	0.004%	0.0004
4000469180	142700	27,093	10/25/2022	11/3/2022	9	0.007%	0.0006
4000469233	8392	12,367	10/26/2022	11/4/2022	9	0.003%	0.0003
4000469236	17844	58,702	10/26/2022	11/4/2022	9	0.015%	0.0014
4000469238	24113	38,348	10/26/2022	11/4/2022	9	0.010%	0.0009
4000469248	34173	13,352	10/26/2022	11/4/2022	9	0.004%	0.0003
4000469251	106699	1,238	10/26/2022	11/4/2022	9	0.000%	0.0000
4000469254	134272	12,364	10/26/2022	11/4/2022	9	0.003%	0.0003
4000469207	15871	489	10/26/2022	11/4/2022	9	0.000%	0.0000
4000469216	116384	31	10/26/2022	11/4/2022	9	0.000%	0.0000
4000469436	18267	2,563	10/31/2022	11/9/2022	9	0.001%	0.0001
4000469444	28474	11,596	10/31/2022	11/9/2022	9	0.003%	0.0003
4000469448	30475	14,028	10/31/2022	11/9/2022	9	0.004%	0.0003
4000469449	32245	773	10/31/2022	11/9/2022	9	0.000%	0.0000
4000469452	105195	27,362	10/31/2022	11/9/2022	9	0.007%	0.0006
4000469407	100203	5,000	10/31/2022	11/9/2022	9	0.001%	0.0001
4000469411	105195	15,551	10/31/2022	11/9/2022	9	0.004%	0.0004
4000469412	113967	5,414	10/31/2022	11/9/2022	9	0.001%	0.0001
4000469418	130634	17,283	10/31/2022	11/9/2022	9	0.005%	0.0004
4000469420	138981	6,400	10/31/2022	11/9/2022	9	0.002%	0.0002
4000469425	143477	4,679	10/31/2022	11/9/2022	9	0.001%	0.0001
4000469470	25173	880	11/1/2022	11/10/2022	9	0.000%	0.0000
4000469480	28084	4,845	11/1/2022	11/10/2022	9	0.001%	0.0001
4000469482	33238	1,103	11/1/2022	11/10/2022	9	0.000%	0.0000
4000469483	33747	3,120	11/1/2022	11/10/2022	9	0.001%	0.0001
4000469461	118807	1,378	11/1/2022	11/10/2022	9	0.000%	0.0000
4000469463	129891	18,300	11/1/2022	11/10/2022	9	0.005%	0.0004
4000469682	25659	17,320	11/7/2022	11/16/2022	9	0.005%	0.0004
4000469662	15871	1,382	11/7/2022	11/16/2022	9	0.000%	0.0000
4000469663	103392	347	11/7/2022	11/16/2022	9	0.000%	0.0000
4000469669	139733	622	11/7/2022	11/16/2022	9	0.000%	0.0000
4000469671	142942	7,479	11/7/2022	11/16/2022	9	0.002%	0.0002
4000469672	143072	27,986	11/7/2022	11/16/2022	9	0.007%	0.0007
4000469676	144561	10,546	11/7/2022	11/16/2022	9	0.003%	0.0003
4000469705	33006	12,650	11/8/2022	11/17/2022	9	0.003%	0.0003
4000469706	33009	8,554	11/8/2022	11/17/2022	9	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469707	33076	6,932	11/8/2022	11/17/2022	9	0.002%	0.0002
4000469708	33080	125,350	11/8/2022	11/17/2022	9	0.033%	0.0030
4000469749	24113	21,770	11/9/2022	11/18/2022	9	0.006%	0.0005
4000469753	25905	1,300	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469757	26604	13,035	11/9/2022	11/18/2022	9	0.003%	0.0003
4000469761	27962	1,767	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469764	32875	1,500	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469711	30580	1,595	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469716	108092	2,850	11/9/2022	11/18/2022	9	0.001%	0.0001
4000469720	123859	1,000	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469721	125742	44	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469723	127898	1,000	11/9/2022	11/18/2022	9	0.000%	0.0000
4000469725	132629	5,000	11/9/2022	11/18/2022	9	0.001%	0.0001
4000469728	142738	2,500	11/9/2022	11/18/2022	9	0.001%	0.0001
4000469859	17342	2,430	11/14/2022	11/23/2022	9	0.001%	0.0001
4000469861	25938	20,991	11/14/2022	11/23/2022	9	0.006%	0.0005
4000469838	32869	3,085	11/14/2022	11/23/2022	9	0.001%	0.0001
4000469854	143569	137,450	11/14/2022	11/23/2022	9	0.036%	0.0033
4000469835	132103	2,890	11/14/2022	11/23/2022	9	0.001%	0.0001
4000469923	25272	1,800	11/16/2022	11/25/2022	9	0.000%	0.0000
4000469926	26213	5,060	11/16/2022	11/25/2022	9	0.001%	0.0001
4000469930	26644	1,080	11/16/2022	11/25/2022	9	0.000%	0.0000
4000469931	26674	2,240	11/16/2022	11/25/2022	9	0.001%	0.0001
4000469934	27982	4,498	11/16/2022	11/25/2022	9	0.001%	0.0001
4000469937	30068	293	11/16/2022	11/25/2022	9	0.000%	0.0000
4000469939	30475	65,665	11/16/2022	11/25/2022	9	0.017%	0.0016
4000469940	30475	67,812	11/16/2022	11/25/2022	9	0.018%	0.0016
4000469941	30475	71,346	11/16/2022	11/25/2022	9	0.019%	0.0017
4000469942	30475	75,650	11/16/2022	11/25/2022	9	0.020%	0.0018
4000469943	30475	83,388	11/16/2022	11/25/2022	9	0.022%	0.0020
4000469944	30475	88,589	11/16/2022	11/25/2022	9	0.023%	0.0021
4000469945	30475	59,401	11/16/2022	11/25/2022	9	0.016%	0.0014
4000469946	32808	550	11/16/2022	11/25/2022	9	0.000%	0.0000
4000469949	33203	585	11/16/2022	11/25/2022	9	0.000%	0.0000
4000469950	33747	2,868	11/16/2022	11/25/2022	9	0.001%	0.0001
4000469910	125742	7,861	11/16/2022	11/25/2022	9	0.002%	0.0002
4000470089	11577	11,445	11/21/2022	11/30/2022	9	0.003%	0.0003
4000470091	24383	680	11/21/2022	11/30/2022	9	0.000%	0.0000
4000470093	25667	2,200	11/21/2022	11/30/2022	9	0.001%	0.0001
4000470094	26639	11,948	11/21/2022	11/30/2022	9	0.003%	0.0003
4000470097	28084	35,340	11/21/2022	11/30/2022	9	0.009%	0.0008
4000470054	26588	3,455	11/21/2022	11/30/2022	9	0.001%	0.0001
4000470057	107767	500	11/21/2022	11/30/2022	9	0.000%	0.0000
4000470058	109714	500	11/21/2022	11/30/2022	9	0.000%	0.0000
4000470061	116384	393	11/21/2022	11/30/2022	9	0.000%	0.0000
4000470070	135057	4,514	11/21/2022	11/30/2022	9	0.001%	0.0001
4000470072	140387	7,500	11/21/2022	11/30/2022	9	0.002%	0.0002
4000470075	142942	4,491	11/21/2022	11/30/2022	9	0.001%	0.0001
4000470078	144247	403,967	11/21/2022	11/30/2022	9	0.107%	0.0096
4000470082	145248	1,500	11/21/2022	11/30/2022	9	0.000%	0.0000
4000470136	25659	548	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470138	25809	2,028	11/22/2022	12/1/2022	9	0.001%	0.0000
4000470139	25905	1,300	11/22/2022	12/1/2022	9	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470143	27482	495	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470109	108289	206	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470110	111669	83	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470116	133875	118	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470117	139982	9,445	11/22/2022	12/1/2022	9	0.002%	0.0002
4000470118	141583	79	11/22/2022	12/1/2022	9	0.000%	0.0000
4000470122	143340	2,300	11/22/2022	12/1/2022	9	0.001%	0.0001
4000470101	126796	3,118	11/22/2022	12/1/2022	9	0.001%	0.0001
4000470159	112215	13,918	11/23/2022	12/2/2022	9	0.004%	0.0003
4000470254	24385	12,568	11/28/2022	12/7/2022	9	0.003%	0.0003
4000470271	28084	14,630	11/28/2022	12/7/2022	9	0.004%	0.0003
4000470278	134272	37,695	11/28/2022	12/7/2022	9	0.010%	0.0009
4000470233	105195	30,367	11/28/2022	12/7/2022	9	0.008%	0.0007
4000470234	110291	7,288	11/28/2022	12/7/2022	9	0.002%	0.0002
4000470235	116384	154	11/28/2022	12/7/2022	9	0.000%	0.0000
4000470238	142885	3,370	11/28/2022	12/7/2022	9	0.001%	0.0001
4000470247	145258	1,076	11/28/2022	12/7/2022	9	0.000%	0.0000
4000470299	11372	2,842	11/29/2022	12/8/2022	9	0.001%	0.0001
4000470300	24383	838	11/29/2022	12/8/2022	9	0.000%	0.0000
4000470306	26642	1,538	11/29/2022	12/8/2022	9	0.000%	0.0000
4000470309	28737	3,184	11/29/2022	12/8/2022	9	0.001%	0.0001
4000470280	36403	18	11/29/2022	12/8/2022	9	0.000%	0.0000
4000470289	143436	836	11/29/2022	12/8/2022	9	0.000%	0.0000
4000470344	9673	8,100	11/30/2022	12/9/2022	9	0.002%	0.0002
4000470346	11474	1,750	11/30/2022	12/9/2022	9	0.000%	0.0000
4000470355	25659	31,008	11/30/2022	12/9/2022	9	0.008%	0.0007
4000470363	26639	8,235	11/30/2022	12/9/2022	9	0.002%	0.0002
4000470364	26643	5,506	11/30/2022	12/9/2022	9	0.001%	0.0001
4000470372	32510	520	11/30/2022	12/9/2022	9	0.000%	0.0000
4000470377	33747	1,656	11/30/2022	12/9/2022	9	0.000%	0.0000
4000470379	33975	9,574	11/30/2022	12/9/2022	9	0.003%	0.0002
4000470330	142926	46,763	11/30/2022	12/9/2022	9	0.012%	0.0011
4000470336	143941	458	11/30/2022	12/9/2022	9	0.000%	0.0000
4000470338	144487	55,671	11/30/2022	12/9/2022	9	0.015%	0.0013
4000470539	6396	8,921	12/5/2022	12/14/2022	9	0.002%	0.0002
4000470541	103008	1,887	12/5/2022	12/14/2022	9	0.000%	0.0000
4000470545	116384	59	12/5/2022	12/14/2022	9	0.000%	0.0000
4000470547	120208	3,000	12/5/2022	12/14/2022	9	0.001%	0.0001
4000470550	129855	427	12/5/2022	12/14/2022	9	0.000%	0.0000
4000470560	144131	500	12/5/2022	12/14/2022	9	0.000%	0.0000
4000470561	144460	2,000	12/5/2022	12/14/2022	9	0.001%	0.0000
4000470590	26588	840	12/6/2022	12/15/2022	9	0.000%	0.0000
4000470595	34088	15,110	12/6/2022	12/15/2022	9	0.004%	0.0004
4000470573	6396	8,921	12/6/2022	12/15/2022	9	0.002%	0.0002
4000470575	103392	304	12/6/2022	12/15/2022	9	0.000%	0.0000
4000470577	107047	18,040	12/6/2022	12/15/2022	9	0.005%	0.0004
4000470580	118989	6	12/6/2022	12/15/2022	9	0.000%	0.0000
4000470586	144422	2,822	12/6/2022	12/15/2022	9	0.001%	0.0001
4000470638	26604	7,695	12/7/2022	12/16/2022	9	0.002%	0.0002
4000470605	103392	20	12/7/2022	12/16/2022	9	0.000%	0.0000
4000470623	143525	6,491	12/7/2022	12/16/2022	9	0.002%	0.0002
4000470624	144084	7,937	12/7/2022	12/16/2022	9	0.002%	0.0002
4000470764	11304	12,450	12/12/2022	12/21/2022	9	0.003%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470765	18267	1,149	12/12/2022	12/21/2022	9	0.000%	0.0000
4000470767	24251	1,800	12/12/2022	12/21/2022	9	0.000%	0.0000
4000470775	27982	8,903	12/12/2022	12/21/2022	9	0.002%	0.0002
4000470744	36403	18	12/12/2022	12/21/2022	9	0.000%	0.0000
4000470746	105024	191	12/12/2022	12/21/2022	9	0.000%	0.0000
4000470749	116384	500	12/12/2022	12/21/2022	9	0.000%	0.0000
4000470802	26679	11,563	12/13/2022	12/22/2022	9	0.003%	0.0003
4000470805	32896	9,075	12/13/2022	12/22/2022	9	0.002%	0.0002
4000470837	9121	500	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470838	10630	6,200	12/14/2022	12/23/2022	9	0.002%	0.0001
4000470840	11577	7,560	12/14/2022	12/23/2022	9	0.002%	0.0002
4000470858	27068	6,099	12/14/2022	12/23/2022	9	0.002%	0.0001
4000470863	33956	4,962	12/14/2022	12/23/2022	9	0.001%	0.0001
4000470810	4765	4,000	12/14/2022	12/23/2022	9	0.001%	0.0001
4000470822	117202	114	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470823	118593	70	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470826	129783	619	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470828	138862	753	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470829	139733	132	12/14/2022	12/23/2022	9	0.000%	0.0000
4000470834	144084	68,620	12/14/2022	12/23/2022	9	0.018%	0.0016
4000470835	145224	150,000	12/14/2022	12/23/2022	9	0.040%	0.0036
4000471046	18267	998	12/19/2022	12/28/2022	9	0.000%	0.0000
4000471033	118807	512	12/19/2022	12/28/2022	9	0.000%	0.0000
4000471034	119139	37,855	12/19/2022	12/28/2022	9	0.010%	0.0009
4000471026	132914	318,250	12/19/2022	12/28/2022	9	0.084%	0.0076
4000471083	11054	7,798	12/20/2022	12/29/2022	9	0.002%	0.0002
4000471086	24825	1,940	12/20/2022	12/29/2022	9	0.001%	0.0000
4000471098	28084	5,035	12/20/2022	12/29/2022	9	0.001%	0.0001
4000471055	4502	6,731	12/20/2022	12/29/2022	9	0.002%	0.0002
4000471061	116384	151	12/20/2022	12/29/2022	9	0.000%	0.0000
4000471072	143340	362,689	12/20/2022	12/29/2022	9	0.096%	0.0086
4000471078	145379	3,000	12/20/2022	12/29/2022	9	0.001%	0.0001
4000471079	116971	3,000	12/20/2022	12/29/2022	9	0.001%	0.0001
4000471139	11260	5,198	12/21/2022	12/30/2022	9	0.001%	0.0001
4000471143	18267	8,664	12/21/2022	12/30/2022	9	0.002%	0.0002
4000471149	25599	375	12/21/2022	12/30/2022	9	0.000%	0.0000
4000471161	26655	849	12/21/2022	12/30/2022	9	0.000%	0.0000
4000471162	26659	4,987	12/21/2022	12/30/2022	9	0.001%	0.0001
4000471165	27994	3,960	12/21/2022	12/30/2022	9	0.001%	0.0001
4000471168	33956	1,017	12/21/2022	12/30/2022	9	0.000%	0.0000
4000471111	27094	27,945	12/21/2022	12/30/2022	9	0.007%	0.0007
4000471130	143796	55,632	12/21/2022	12/30/2022	9	0.015%	0.0013
4000471131	144015	10,000	12/21/2022	12/30/2022	9	0.003%	0.0002
4000471134	145352	1,500	12/21/2022	12/30/2022	9	0.000%	0.0000
4000471136	145531	31,617	12/21/2022	12/30/2022	9	0.008%	0.0008
4000471285	24281	18,609	12/27/2022	1/5/2023	9	0.005%	0.0004
4000471287	25808	27,300	12/27/2022	1/5/2023	9	0.007%	0.0006
4000471288	25905	600	12/27/2022	1/5/2023	9	0.000%	0.0000
4000471289	25908	3,375	12/27/2022	1/5/2023	9	0.001%	0.0001
4000471292	26588	13,145	12/27/2022	1/5/2023	9	0.003%	0.0003
4000471293	26604	3,070	12/27/2022	1/5/2023	9	0.001%	0.0001
4000471294	26639	12,690	12/27/2022	1/5/2023	9	0.003%	0.0003
4000471271	113448	10,939	12/27/2022	1/5/2023	9	0.003%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471272	116384	349	12/27/2022	1/5/2023	9	0.000%	0.0000
4000471276	143072	928	12/27/2022	1/5/2023	9	0.000%	0.0000
4000471278	143426	20,690	12/27/2022	1/5/2023	9	0.005%	0.0005
4000471320	25173	2,640	12/28/2022	1/6/2023	9	0.001%	0.0001
4000471321	26213	2,070	12/28/2022	1/6/2023	9	0.001%	0.0000
4000471326	27162	1,100	12/28/2022	1/6/2023	9	0.000%	0.0000
4000471298	4765	14,398	12/28/2022	1/6/2023	9	0.004%	0.0003
4000471299	6396	41,656	12/28/2022	1/6/2023	9	0.011%	0.0010
4000471309	116384	4	12/28/2022	1/6/2023	9	0.000%	0.0000
4000459558	28084	8,550	1/3/2022	1/13/2022	10	0.002%	0.0002
4000459559	33747	606	1/3/2022	1/13/2022	10	0.000%	0.0000
4000459563	117331	3,300	1/3/2022	1/13/2022	10	0.001%	0.0001
4000459549	134664	2,245	1/3/2022	1/13/2022	10	0.001%	0.0001
4000459551	142635	7,881	1/3/2022	1/13/2022	10	0.002%	0.0002
4000459585	24251	3,180	1/4/2022	1/14/2022	10	0.001%	0.0001
4000459576	116384	4	1/4/2022	1/14/2022	10	0.000%	0.0000
4000459577	125742	7,856	1/4/2022	1/14/2022	10	0.002%	0.0002
4000459721	25131	950	1/10/2022	1/20/2022	10	0.000%	0.0000
4000459737	124943	665	1/10/2022	1/20/2022	10	0.000%	0.0000
4000459739	133795	11,499	1/10/2022	1/20/2022	10	0.003%	0.0003
4000459707	143413	37,479	1/10/2022	1/20/2022	10	0.010%	0.0010
4000459768	34531	48,436	1/11/2022	1/21/2022	10	0.013%	0.0013
4000459748	139184	58,500	1/11/2022	1/21/2022	10	0.015%	0.0015
4000459988	14463	17,895	1/18/2022	1/28/2022	10	0.005%	0.0005
4000460002	30475	20,864	1/18/2022	1/28/2022	10	0.006%	0.0006
4000460003	30475	15,216	1/18/2022	1/28/2022	10	0.004%	0.0004
4000460004	32875	1,900	1/18/2022	1/28/2022	10	0.001%	0.0001
4000460009	106699	3,828	1/18/2022	1/28/2022	10	0.001%	0.0001
4000459954	4502	77,733	1/18/2022	1/28/2022	10	0.021%	0.0021
4000460110	112215	928	1/21/2022	1/31/2022	10	0.000%	0.0000
4000460160	26577	1,750	1/24/2022	2/3/2022	10	0.000%	0.0000
4000460165	33747	705	1/24/2022	2/3/2022	10	0.000%	0.0000
4000460131	10384	4,000	1/24/2022	2/3/2022	10	0.001%	0.0001
4000460147	143569	7,050	1/24/2022	2/3/2022	10	0.002%	0.0002
4000460148	144825	15,587	1/24/2022	2/3/2022	10	0.004%	0.0004
4000460169	32971	2,471	1/24/2022	2/3/2022	10	0.001%	0.0001
4000460174	32985	11,550	1/24/2022	2/3/2022	10	0.003%	0.0003
4000460175	32990	10,228	1/24/2022	2/3/2022	10	0.003%	0.0003
4000460180	33011	17,838	1/24/2022	2/3/2022	10	0.005%	0.0005
4000460181	33012	434	1/24/2022	2/3/2022	10	0.000%	0.0000
4000460182	33013	17,801	1/24/2022	2/3/2022	10	0.005%	0.0005
4000460203	33047	28,915	1/24/2022	2/3/2022	10	0.008%	0.0008
4000460206	33050	77,230	1/24/2022	2/3/2022	10	0.020%	0.0020
4000460208	33053	19,138	1/24/2022	2/3/2022	10	0.005%	0.0005
4000460212	33057	1,061	1/24/2022	2/3/2022	10	0.000%	0.0000
4000460213	33058	573	1/24/2022	2/3/2022	10	0.000%	0.0000
4000460216	33061	3,607	1/24/2022	2/3/2022	10	0.001%	0.0001
4000460220	33068	282,360	1/24/2022	2/3/2022	10	0.074%	0.0074
4000460222	33086	7,759	1/24/2022	2/3/2022	10	0.002%	0.0002
4000460254	24251	1,020	1/25/2022	2/4/2022	10	0.000%	0.0000
4000460257	25716	11,415	1/25/2022	2/4/2022	10	0.003%	0.0003
4000460260	27068	21,109	1/25/2022	2/4/2022	10	0.006%	0.0006
4000460261	27162	1,100	1/25/2022	2/4/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460263	28084	3,848	1/25/2022	2/4/2022	10	0.001%	0.0001
4000460269	32875	2,800	1/25/2022	2/4/2022	10	0.001%	0.0001
4000460271	105195	3,164	1/25/2022	2/4/2022	10	0.001%	0.0001
4000460233	105195	1,383	1/25/2022	2/4/2022	10	0.000%	0.0000
4000460236	116051	3,998	1/25/2022	2/4/2022	10	0.001%	0.0001
4000460242	142926	3,086	1/25/2022	2/4/2022	10	0.001%	0.0001
4000460246	143659	90,400	1/25/2022	2/4/2022	10	0.024%	0.0024
4000460491	33021	105,357	1/28/2022	2/7/2022	10	0.028%	0.0028
4000460492	33027	2,847	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460493	33038	2,438	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460494	33067	53,243	1/28/2022	2/7/2022	10	0.014%	0.0014
4000460502	33077	14,991	1/28/2022	2/7/2022	10	0.004%	0.0004
4000460503	33079	19,203	1/28/2022	2/7/2022	10	0.005%	0.0005
4000460504	33080	119,748	1/28/2022	2/7/2022	10	0.032%	0.0032
4000460506	33082	655	1/28/2022	2/7/2022	10	0.000%	0.0000
4000460509	33088	2,421	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460512	33093	132	1/28/2022	2/7/2022	10	0.000%	0.0000
4000460517	33099	29,022	1/28/2022	2/7/2022	10	0.008%	0.0008
4000460528	33115	2,153	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460541	33130	193	1/28/2022	2/7/2022	10	0.000%	0.0000
4000460543	33132	2,062	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460547	33136	2,178	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460548	33137	7,020	1/28/2022	2/7/2022	10	0.002%	0.0002
4000460549	33138	3,949	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460554	33144	29,789	1/28/2022	2/7/2022	10	0.008%	0.0008
4000460560	33152	4,845	1/28/2022	2/7/2022	10	0.001%	0.0001
4000460561	33153	12,007	1/28/2022	2/7/2022	10	0.003%	0.0003
4000460586	11474	4,375	1/31/2022	2/10/2022	10	0.001%	0.0001
4000460591	24259	514	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460598	25716	42,255	1/31/2022	2/10/2022	10	0.011%	0.0011
4000460599	26213	2,484	1/31/2022	2/10/2022	10	0.001%	0.0001
4000460600	26301	599	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460603	26363	1,863	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460604	26381	3,360	1/31/2022	2/10/2022	10	0.001%	0.0001
4000460606	26604	655	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460611	28084	20,948	1/31/2022	2/10/2022	10	0.006%	0.0006
4000460612	33238	420	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460565	32099	600	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460569	108092	3,150	1/31/2022	2/10/2022	10	0.001%	0.0001
4000460571	123042	17,748	1/31/2022	2/10/2022	10	0.005%	0.0005
4000460574	139487	66	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460578	143477	4,833	1/31/2022	2/10/2022	10	0.001%	0.0001
4000460615	32923	6	1/31/2022	2/10/2022	10	0.000%	0.0000
4000460669	30228	31,746	2/1/2022	2/11/2022	10	0.008%	0.0008
4000460620	15871	1,893	2/1/2022	2/11/2022	10	0.000%	0.0000
4000460635	139521	4,011	2/1/2022	2/11/2022	10	0.001%	0.0001
4000460643	141884	10,288	2/1/2022	2/11/2022	10	0.003%	0.0003
4000460644	142002	7,696	2/1/2022	2/11/2022	10	0.002%	0.0002
4000460791	18267	2,570	2/4/2022	2/14/2022	10	0.001%	0.0001
4000460805	34064	125	2/4/2022	2/14/2022	10	0.000%	0.0000
4000460806	34341	3,147	2/4/2022	2/14/2022	10	0.001%	0.0001
4000460768	105195	7,007	2/4/2022	2/14/2022	10	0.002%	0.0002
4000460770	115761	205	2/4/2022	2/14/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460776	125742	32,688	2/4/2022	2/14/2022	10	0.009%	0.0009
4000460780	143111	2,400	2/4/2022	2/14/2022	10	0.001%	0.0001
4000460785	144666	8,722	2/4/2022	2/14/2022	10	0.002%	0.0002
4000460827	9673	5,850	2/7/2022	2/17/2022	10	0.002%	0.0002
4000460831	11536	11,983	2/7/2022	2/17/2022	10	0.003%	0.0003
4000460840	26604	4,860	2/7/2022	2/17/2022	10	0.001%	0.0001
4000460845	28084	9,215	2/7/2022	2/17/2022	10	0.002%	0.0002
4000460848	33747	528	2/7/2022	2/17/2022	10	0.000%	0.0000
4000460812	32842	1,836	2/7/2022	2/17/2022	10	0.000%	0.0000
4000460817	125742	16,800	2/7/2022	2/17/2022	10	0.004%	0.0004
4000460820	139089	150	2/7/2022	2/17/2022	10	0.000%	0.0000
4000460810	127614	3,605	2/7/2022	2/17/2022	10	0.001%	0.0001
4000460878	24281	21,042	2/8/2022	2/18/2022	10	0.006%	0.0006
4000460881	26643	8,231	2/8/2022	2/18/2022	10	0.002%	0.0002
4000460882	26644	1,080	2/8/2022	2/18/2022	10	0.000%	0.0000
4000460858	118807	653	2/8/2022	2/18/2022	10	0.000%	0.0000
4000460863	125742	147	2/8/2022	2/18/2022	10	0.000%	0.0000
4000460865	129119	2,318	2/8/2022	2/18/2022	10	0.001%	0.0001
4000460868	133986	2,018	2/8/2022	2/18/2022	10	0.001%	0.0001
4000461062	24259	1,349	2/14/2022	2/24/2022	10	0.000%	0.0000
4000461063	26297	1,478	2/14/2022	2/24/2022	10	0.000%	0.0000
4000461065	26338	5,408	2/14/2022	2/24/2022	10	0.001%	0.0001
4000461066	26361	1,142	2/14/2022	2/24/2022	10	0.000%	0.0000
4000461070	26667	8,675	2/14/2022	2/24/2022	10	0.002%	0.0002
4000461071	26674	1,680	2/14/2022	2/24/2022	10	0.000%	0.0000
4000461076	134272	305,660	2/14/2022	2/24/2022	10	0.081%	0.0081
4000461049	119251	103,905	2/14/2022	2/24/2022	10	0.027%	0.0027
4000461094	9121	2,400	2/15/2022	2/25/2022	10	0.001%	0.0001
4000461095	25173	2,640	2/15/2022	2/25/2022	10	0.001%	0.0001
4000461219	112215	8,332	2/18/2022	2/28/2022	10	0.002%	0.0002
4000461220	116332	291,547	2/18/2022	2/28/2022	10	0.077%	0.0077
4000461303	27068	7,937	2/22/2022	3/4/2022	10	0.002%	0.0002
4000461310	34173	1,242	2/22/2022	3/4/2022	10	0.000%	0.0000
4000461265	32138	6,070	2/22/2022	3/4/2022	10	0.002%	0.0002
4000461269	107313	5,000	2/22/2022	3/4/2022	10	0.001%	0.0001
4000461287	141583	671	2/22/2022	3/4/2022	10	0.000%	0.0000
4000461443	18267	2,048	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461446	24281	3,632	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461452	27013	19,091	2/25/2022	3/7/2022	10	0.005%	0.0005
4000461458	30257	6,111	2/25/2022	3/7/2022	10	0.002%	0.0002
4000461459	30475	187,357	2/25/2022	3/7/2022	10	0.049%	0.0049
4000461463	105195	3,670	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461467	126775	4,898	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461407	10384	17,800	2/25/2022	3/7/2022	10	0.005%	0.0005
4000461408	15871	75	2/25/2022	3/7/2022	10	0.000%	0.0000
4000461409	19534	12,695	2/25/2022	3/7/2022	10	0.003%	0.0003
4000461413	32842	3,215	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461414	33238	1,890	2/25/2022	3/7/2022	10	0.000%	0.0000
4000461415	101709	1,100	2/25/2022	3/7/2022	10	0.000%	0.0000
4000461421	116384	150	2/25/2022	3/7/2022	10	0.000%	0.0000
4000461425	135488	97	2/25/2022	3/7/2022	10	0.000%	0.0000
4000461432	142998	9,900	2/25/2022	3/7/2022	10	0.003%	0.0003
4000461433	143477	19,703	2/25/2022	3/7/2022	10	0.005%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461436	144530	68,199	2/25/2022	3/7/2022	10	0.018%	0.0018
4000461437	116971	3,000	2/25/2022	3/7/2022	10	0.001%	0.0001
4000461497	11054	8,623	2/28/2022	3/10/2022	10	0.002%	0.0002
4000461500	14463	10,268	2/28/2022	3/10/2022	10	0.003%	0.0003
4000461507	26604	3,500	2/28/2022	3/10/2022	10	0.001%	0.0001
4000461511	28737	5,000	2/28/2022	3/10/2022	10	0.001%	0.0001
4000461513	32875	2,100	2/28/2022	3/10/2022	10	0.001%	0.0001
4000461515	34173	36,484	2/28/2022	3/10/2022	10	0.010%	0.0010
4000461469	9145	31,650	2/28/2022	3/10/2022	10	0.008%	0.0008
4000461489	134986	10,000	2/28/2022	3/10/2022	10	0.003%	0.0003
4000461494	144581	2,960	2/28/2022	3/10/2022	10	0.001%	0.0001
4000461649	143867	22,784	3/4/2022	3/14/2022	10	0.006%	0.0006
4000461650	144208	694,535	3/4/2022	3/14/2022	10	0.183%	0.0183
4000461681	104872	366	3/7/2022	3/17/2022	10	0.000%	0.0000
4000461683	105205	1,000	3/7/2022	3/17/2022	10	0.000%	0.0000
4000461684	111529	2,500	3/7/2022	3/17/2022	10	0.001%	0.0001
4000461724	24251	5,220	3/8/2022	3/18/2022	10	0.001%	0.0001
4000461729	27068	808	3/8/2022	3/18/2022	10	0.000%	0.0000
4000461734	134272	108,830	3/8/2022	3/18/2022	10	0.029%	0.0029
4000461713	104872	740	3/8/2022	3/18/2022	10	0.000%	0.0000
4000461721	142942	644	3/8/2022	3/18/2022	10	0.000%	0.0000
4000461840	13534	17,595	3/11/2022	3/21/2022	10	0.005%	0.0005
4000461841	18267	4,616	3/11/2022	3/21/2022	10	0.001%	0.0001
4000461847	34064	808	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461848	34341	13,200	3/11/2022	3/21/2022	10	0.003%	0.0003
4000461851	34658	14,160	3/11/2022	3/21/2022	10	0.004%	0.0004
4000461852	105195	3,113	3/11/2022	3/21/2022	10	0.001%	0.0001
4000461853	133795	10,224	3/11/2022	3/21/2022	10	0.003%	0.0003
4000461809	16767	2,028	3/11/2022	3/21/2022	10	0.001%	0.0001
4000461810	20287	325	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461811	21678	268,722	3/11/2022	3/21/2022	10	0.071%	0.0071
4000461812	25093	7,050	3/11/2022	3/21/2022	10	0.002%	0.0002
4000461813	27476	5,634	3/11/2022	3/21/2022	10	0.001%	0.0001
4000461815	33238	998	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461821	116384	445	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461822	118807	4,359	3/11/2022	3/21/2022	10	0.001%	0.0001
4000461825	129387	7,000	3/11/2022	3/21/2022	10	0.002%	0.0002
4000461827	135488	1,213	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461829	138343	1,724	3/11/2022	3/21/2022	10	0.000%	0.0000
4000461832	143659	30,186	3/11/2022	3/21/2022	10	0.008%	0.0008
4000461834	144530	77,942	3/11/2022	3/21/2022	10	0.021%	0.0021
4000461835	144567	6,000	3/11/2022	3/21/2022	10	0.002%	0.0002
4000461868	24259	583	3/14/2022	3/24/2022	10	0.000%	0.0000
4000461860	125742	15,838	3/14/2022	3/24/2022	10	0.004%	0.0004
4000461899	9891	520	3/15/2022	3/25/2022	10	0.000%	0.0000
4000461902	11577	630	3/15/2022	3/25/2022	10	0.000%	0.0000
4000461908	25437	1,200	3/15/2022	3/25/2022	10	0.000%	0.0000
4000461914	27994	7,205	3/15/2022	3/25/2022	10	0.002%	0.0002
4000461887	125742	11,671	3/15/2022	3/25/2022	10	0.003%	0.0003
4000461894	142942	7,995	3/15/2022	3/25/2022	10	0.002%	0.0002
4000462036	18267	1,402	3/18/2022	3/28/2022	10	0.000%	0.0000
4000462039	24281	1,816	3/18/2022	3/28/2022	10	0.000%	0.0000
4000462045	27013	18,211	3/18/2022	3/28/2022	10	0.005%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462049	30475	74,777	3/18/2022	3/28/2022	10	0.020%	0.0020
4000462050	30475	87,360	3/18/2022	3/28/2022	10	0.023%	0.0023
4000462051	30475	59,331	3/18/2022	3/28/2022	10	0.016%	0.0016
4000462052	30475	66,225	3/18/2022	3/28/2022	10	0.017%	0.0017
4000462053	34341	7,000	3/18/2022	3/28/2022	10	0.002%	0.0002
4000462008	10055	19,748	3/18/2022	3/28/2022	10	0.005%	0.0005
4000462010	15871	2,474	3/18/2022	3/28/2022	10	0.001%	0.0001
4000462011	27094	26,464	3/18/2022	3/28/2022	10	0.007%	0.0007
4000462012	32842	414	3/18/2022	3/28/2022	10	0.000%	0.0000
4000462015	116384	193	3/18/2022	3/28/2022	10	0.000%	0.0000
4000462016	118807	79	3/18/2022	3/28/2022	10	0.000%	0.0000
4000462020	135488	50,092	3/18/2022	3/28/2022	10	0.013%	0.0013
4000462024	142376	20,995	3/18/2022	3/28/2022	10	0.006%	0.0006
4000462026	142942	22,031	3/18/2022	3/28/2022	10	0.006%	0.0006
4000462028	143529	4,526	3/18/2022	3/28/2022	10	0.001%	0.0001
4000462031	144567	11,420	3/18/2022	3/28/2022	10	0.003%	0.0003
4000462032	144567	11,978	3/18/2022	3/28/2022	10	0.003%	0.0003
4000462033	144567	10,553	3/18/2022	3/28/2022	10	0.003%	0.0003
4000462034	144878	17,831	3/18/2022	3/28/2022	10	0.005%	0.0005
4000462084	8392	4,469	3/21/2022	3/31/2022	10	0.001%	0.0001
4000462086	11304	6,150	3/21/2022	3/31/2022	10	0.002%	0.0002
4000462090	24211	2,778	3/21/2022	3/31/2022	10	0.001%	0.0001
4000462104	26604	8,780	3/21/2022	3/31/2022	10	0.002%	0.0002
4000462111	26679	1,750	3/21/2022	3/31/2022	10	0.000%	0.0000
4000462114	126165	51,320	3/21/2022	3/31/2022	10	0.014%	0.0014
4000462063	108289	602	3/21/2022	3/31/2022	10	0.000%	0.0000
4000462082	144583	4,100	3/21/2022	3/31/2022	10	0.001%	0.0001
4000462128	144996	2,500	3/22/2022	4/1/2022	10	0.001%	0.0001
4000462232	30257	5,955	3/25/2022	4/4/2022	10	0.002%	0.0002
4000462234	33956	3,939	3/25/2022	4/4/2022	10	0.001%	0.0001
4000462235	34064	151	3/25/2022	4/4/2022	10	0.000%	0.0000
4000462238	34658	2,030	3/25/2022	4/4/2022	10	0.001%	0.0001
4000462200	7529	9,932	3/25/2022	4/4/2022	10	0.003%	0.0003
4000462201	9145	16,925	3/25/2022	4/4/2022	10	0.004%	0.0004
4000462206	103392	293	3/25/2022	4/4/2022	10	0.000%	0.0000
4000462209	116384	58	3/25/2022	4/4/2022	10	0.000%	0.0000
4000462210	125742	15,080	3/25/2022	4/4/2022	10	0.004%	0.0004
4000462212	135488	22,944	3/25/2022	4/4/2022	10	0.006%	0.0006
4000462219	143436	2,956	3/25/2022	4/4/2022	10	0.001%	0.0001
4000462220	143659	20,363	3/25/2022	4/4/2022	10	0.005%	0.0005
4000462221	143920	92	3/25/2022	4/4/2022	10	0.000%	0.0000
4000462256	11260	2,705	3/28/2022	4/7/2022	10	0.001%	0.0001
4000462258	11577	840	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462260	24259	2,762	3/28/2022	4/7/2022	10	0.001%	0.0001
4000462263	25379	975	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462266	26323	1,236	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462274	28737	10,500	3/28/2022	4/7/2022	10	0.003%	0.0003
4000462276	33238	788	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462278	126165	1,894	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462245	104872	141	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462252	132321	104	3/28/2022	4/7/2022	10	0.000%	0.0000
4000462302	13911	61,655	3/29/2022	4/8/2022	10	0.016%	0.0016
4000462311	26643	1,572	3/29/2022	4/8/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462524	24113	1,608	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462535	30475	58,987	4/1/2022	4/11/2022	10	0.016%	0.0016
4000462536	30475	64,246	4/1/2022	4/11/2022	10	0.017%	0.0017
4000462537	30475	71,194	4/1/2022	4/11/2022	10	0.019%	0.0019
4000462538	30475	116,822	4/1/2022	4/11/2022	10	0.031%	0.0031
4000462539	30475	124,851	4/1/2022	4/11/2022	10	0.033%	0.0033
4000462542	33956	950	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462543	34064	23	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462544	34341	3,300	4/1/2022	4/11/2022	10	0.001%	0.0001
4000462478	34888	3,549	4/1/2022	4/11/2022	10	0.001%	0.0001
4000462482	104154	880	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462488	116384	463	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462489	118807	106	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462492	125742	10,380	4/1/2022	4/11/2022	10	0.003%	0.0003
4000462495	135488	8,160	4/1/2022	4/11/2022	10	0.002%	0.0002
4000462500	139713	85,735	4/1/2022	4/11/2022	10	0.023%	0.0023
4000462503	142926	28,360	4/1/2022	4/11/2022	10	0.007%	0.0007
4000462506	143154	808	4/1/2022	4/11/2022	10	0.000%	0.0000
4000462507	143867	24,411	4/1/2022	4/11/2022	10	0.006%	0.0006
4000462510	144097	615,982	4/1/2022	4/11/2022	10	0.162%	0.0162
4000462567	142164	5,356	4/4/2022	4/14/2022	10	0.001%	0.0001
4000462573	143400	3,000	4/4/2022	4/14/2022	10	0.001%	0.0001
4000462576	143807	1,058	4/4/2022	4/14/2022	10	0.000%	0.0000
4000462584	144801	52,093	4/4/2022	4/14/2022	10	0.014%	0.0014
4000462616	34173	10,764	4/5/2022	4/15/2022	10	0.003%	0.0003
4000462727	18267	7,780	4/8/2022	4/18/2022	10	0.002%	0.0002
4000462741	34341	13,200	4/8/2022	4/18/2022	10	0.003%	0.0003
4000462743	105195	5,500	4/8/2022	4/18/2022	10	0.001%	0.0001
4000462691	27094	57,232	4/8/2022	4/18/2022	10	0.015%	0.0015
4000462693	101853	12,600	4/8/2022	4/18/2022	10	0.003%	0.0003
4000462697	112215	2,524	4/8/2022	4/18/2022	10	0.001%	0.0001
4000462698	116384	58	4/8/2022	4/18/2022	10	0.000%	0.0000
4000462701	125742	53,477	4/8/2022	4/18/2022	10	0.014%	0.0014
4000462705	138494	12,000	4/8/2022	4/18/2022	10	0.003%	0.0003
4000462706	138862	116	4/8/2022	4/18/2022	10	0.000%	0.0000
4000462708	142635	52,618	4/8/2022	4/18/2022	10	0.014%	0.0014
4000462712	143485	139,545	4/8/2022	4/18/2022	10	0.037%	0.0037
4000462714	144097	17,890	4/8/2022	4/18/2022	10	0.005%	0.0005
4000462716	144292	4,298	4/8/2022	4/18/2022	10	0.001%	0.0001
4000462719	144567	6,250	4/8/2022	4/18/2022	10	0.002%	0.0002
4000462721	144663	74,917	4/8/2022	4/18/2022	10	0.020%	0.0020
4000462723	144955	2,320	4/8/2022	4/18/2022	10	0.001%	0.0001
4000462760	9121	700	4/11/2022	4/21/2022	10	0.000%	0.0000
4000462764	13911	10,105	4/11/2022	4/21/2022	10	0.003%	0.0003
4000462773	26679	1,875	4/11/2022	4/21/2022	10	0.000%	0.0000
4000462774	27962	1,824	4/11/2022	4/21/2022	10	0.000%	0.0000
4000462746	7529	3,096	4/11/2022	4/21/2022	10	0.001%	0.0001
4000462759	145005	1,000	4/11/2022	4/21/2022	10	0.000%	0.0000
4000462788	144430	500	4/12/2022	4/22/2022	10	0.000%	0.0000
4000462953	25131	1,805	4/18/2022	4/28/2022	10	0.000%	0.0000
4000462955	27704	1,600	4/18/2022	4/28/2022	10	0.000%	0.0000
4000462956	27994	990	4/18/2022	4/28/2022	10	0.000%	0.0000
4000462959	32808	1,540	4/18/2022	4/28/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462960	32875	2,500	4/18/2022	4/28/2022	10	0.001%	0.0001
4000462962	34069	1,300	4/18/2022	4/28/2022	10	0.000%	0.0000
4000462940	123042	17,748	4/18/2022	4/28/2022	10	0.005%	0.0005
4000462948	144190	344	4/18/2022	4/28/2022	10	0.000%	0.0000
4000462967	102473	3,900	4/19/2022	4/29/2022	10	0.001%	0.0001
4000463118	25173	880	4/22/2022	5/2/2022	10	0.000%	0.0000
4000463092	125742	8,012	4/22/2022	5/2/2022	10	0.002%	0.0002
4000463096	138494	3,080	4/22/2022	5/2/2022	10	0.001%	0.0001
4000463097	139713	85,735	4/22/2022	5/2/2022	10	0.023%	0.0023
4000463104	143520	2,779	4/22/2022	5/2/2022	10	0.001%	0.0001
4000463105	143867	8,137	4/22/2022	5/2/2022	10	0.002%	0.0002
4000463106	143944	848	4/22/2022	5/2/2022	10	0.000%	0.0000
4000463107	144097	710,050	4/22/2022	5/2/2022	10	0.187%	0.0187
4000463110	144663	19,474	4/22/2022	5/2/2022	10	0.005%	0.0005
4000463173	25659	11,100	4/25/2022	5/5/2022	10	0.003%	0.0003
4000463176	28737	15,600	4/25/2022	5/5/2022	10	0.004%	0.0004
4000463144	118777	5,000	4/25/2022	5/5/2022	10	0.001%	0.0001
4000463374	24383	18,485	4/29/2022	5/9/2022	10	0.005%	0.0005
4000463375	24383	17,490	4/29/2022	5/9/2022	10	0.005%	0.0005
4000463377	25173	2,723	4/29/2022	5/9/2022	10	0.001%	0.0001
4000463329	27466	3,125	4/29/2022	5/9/2022	10	0.001%	0.0001
4000463339	133414	1,741	4/29/2022	5/9/2022	10	0.000%	0.0000
4000463341	135057	133	4/29/2022	5/9/2022	10	0.000%	0.0000
4000463343	135488	17,553	4/29/2022	5/9/2022	10	0.005%	0.0005
4000463351	143312	151,395	4/29/2022	5/9/2022	10	0.040%	0.0040
4000463354	143606	110,570	4/29/2022	5/9/2022	10	0.029%	0.0029
4000463355	143637	3,750	4/29/2022	5/9/2022	10	0.001%	0.0001
4000463324	129121	28,634	4/29/2022	5/9/2022	10	0.008%	0.0008
4000463425	24259	1,542	5/2/2022	5/12/2022	10	0.000%	0.0000
4000463437	27962	1,824	5/2/2022	5/12/2022	10	0.000%	0.0000
4000463407	104872	344	5/2/2022	5/12/2022	10	0.000%	0.0000
4000463421	141583	158	5/2/2022	5/12/2022	10	0.000%	0.0000
4000463504	9673	400	5/3/2022	5/13/2022	10	0.000%	0.0000
4000463457	104872	743	5/3/2022	5/13/2022	10	0.000%	0.0000
4000463478	142002	7,696	5/3/2022	5/13/2022	10	0.002%	0.0002
4000463491	144047	125	5/3/2022	5/13/2022	10	0.000%	0.0000
4000463492	144270	8,295	5/3/2022	5/13/2022	10	0.002%	0.0002
4000463497	144927	6,000	5/3/2022	5/13/2022	10	0.002%	0.0002
4000463610	11474	875	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463622	34341	7,538	5/6/2022	5/16/2022	10	0.002%	0.0002
4000463578	15871	5,989	5/6/2022	5/16/2022	10	0.002%	0.0002
4000463582	32842	3,748	5/6/2022	5/16/2022	10	0.001%	0.0001
4000463583	101853	1,452	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463585	112215	14,404	5/6/2022	5/16/2022	10	0.004%	0.0004
4000463586	115998	400	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463587	116051	4,325	5/6/2022	5/16/2022	10	0.001%	0.0001
4000463588	116332	41,863	5/6/2022	5/16/2022	10	0.011%	0.0011
4000463589	116384	568	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463590	125742	13,375	5/6/2022	5/16/2022	10	0.004%	0.0004
4000463591	125951	52	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463592	138494	1,785	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463593	138862	345	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463595	142635	53,912	5/6/2022	5/16/2022	10	0.014%	0.0014

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463599	143485	139,545	5/6/2022	5/16/2022	10	0.037%	0.0037
4000463604	144567	30,731	5/6/2022	5/16/2022	10	0.008%	0.0008
4000463606	144949	564	5/6/2022	5/16/2022	10	0.000%	0.0000
4000463643	27994	1,375	5/9/2022	5/19/2022	10	0.000%	0.0000
4000463650	104872	31	5/10/2022	5/20/2022	10	0.000%	0.0000
4000463655	124628	29,640	5/10/2022	5/20/2022	10	0.008%	0.0008
4000463800	26490	2,027	5/13/2022	5/23/2022	10	0.001%	0.0001
4000463818	34064	690	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463819	34341	14,700	5/13/2022	5/23/2022	10	0.004%	0.0004
4000463758	26604	1,295	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463764	101740	59,258	5/13/2022	5/23/2022	10	0.016%	0.0016
4000463767	108501	201,696	5/13/2022	5/23/2022	10	0.053%	0.0053
4000463768	115998	160	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463769	116384	683	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463770	118807	88	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463774	126775	3,531	5/13/2022	5/23/2022	10	0.001%	0.0001
4000463776	129855	432	5/13/2022	5/23/2022	10	0.000%	0.0000
4000463778	139713	41,095	5/13/2022	5/23/2022	10	0.011%	0.0011
4000463782	143312	59,269	5/13/2022	5/23/2022	10	0.016%	0.0016
4000463783	143477	21,849	5/13/2022	5/23/2022	10	0.006%	0.0006
4000463785	144567	18,277	5/13/2022	5/23/2022	10	0.005%	0.0005
4000463786	144567	14,106	5/13/2022	5/23/2022	10	0.004%	0.0004
4000463889	25987	7,650	5/16/2022	5/26/2022	10	0.002%	0.0002
4000463890	26297	104	5/16/2022	5/26/2022	10	0.000%	0.0000
4000463892	26361	15,502	5/16/2022	5/26/2022	10	0.004%	0.0004
4000463895	26679	750	5/16/2022	5/26/2022	10	0.000%	0.0000
4000463898	27981	3,540	5/16/2022	5/26/2022	10	0.001%	0.0001
4000463825	12331	25,000	5/16/2022	5/26/2022	10	0.007%	0.0007
4000463835	110708	1,700	5/16/2022	5/26/2022	10	0.000%	0.0000
4000463837	115781	7,500	5/16/2022	5/26/2022	10	0.002%	0.0002
4000463843	122311	5,000	5/16/2022	5/26/2022	10	0.001%	0.0001
4000463849	125445	3,000	5/16/2022	5/26/2022	10	0.001%	0.0001
4000463857	129014	10,000	5/16/2022	5/26/2022	10	0.003%	0.0003
4000463864	141590	7,500	5/16/2022	5/26/2022	10	0.002%	0.0002
4000463908	104872	1,286	5/17/2022	5/27/2022	10	0.000%	0.0000
4000464092	25131	1,710	5/23/2022	6/2/2022	10	0.000%	0.0000
4000464093	27013	1,617	5/23/2022	6/2/2022	10	0.000%	0.0000
4000464066	6396	5,950	5/23/2022	6/2/2022	10	0.002%	0.0002
4000464067	103392	256	5/23/2022	6/2/2022	10	0.000%	0.0000
4000464076	119733	1,000	5/23/2022	6/2/2022	10	0.000%	0.0000
4000464085	144791	800	5/23/2022	6/2/2022	10	0.000%	0.0000
4000464086	145131	13,966	5/23/2022	6/2/2022	10	0.004%	0.0004
4000464065	102060	10,000	5/23/2022	6/2/2022	10	0.003%	0.0003
4000464088	116971	3,000	5/23/2022	6/2/2022	10	0.001%	0.0001
4000464119	26213	690	5/24/2022	6/3/2022	10	0.000%	0.0000
4000464120	26577	1,500	5/24/2022	6/3/2022	10	0.000%	0.0000
4000464121	26604	6,415	5/24/2022	6/3/2022	10	0.002%	0.0002
4000464128	32510	1,087	5/24/2022	6/3/2022	10	0.000%	0.0000
4000464130	33770	2,588	5/24/2022	6/3/2022	10	0.001%	0.0001
4000464097	104872	22	5/24/2022	6/3/2022	10	0.000%	0.0000
4000464257	112215	680	5/27/2022	6/6/2022	10	0.000%	0.0000
4000464262	121825	88,492	5/27/2022	6/6/2022	10	0.023%	0.0023
4000464265	125742	482	5/27/2022	6/6/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464271	139713	248,550	5/27/2022	6/6/2022	10	0.066%	0.0066
4000464273	142635	23,519	5/27/2022	6/6/2022	10	0.006%	0.0006
4000464283	144270	77,800	5/27/2022	6/6/2022	10	0.021%	0.0021
4000464343	9891	1,170	5/31/2022	6/10/2022	10	0.000%	0.0000
4000464345	11304	9,075	5/31/2022	6/10/2022	10	0.002%	0.0002
4000464349	25659	6,818	5/31/2022	6/10/2022	10	0.002%	0.0002
4000464350	25987	900	5/31/2022	6/10/2022	10	0.000%	0.0000
4000464354	26323	6,611	5/31/2022	6/10/2022	10	0.002%	0.0002
4000464356	26363	22,192	5/31/2022	6/10/2022	10	0.006%	0.0006
4000464360	26643	1,751	5/31/2022	6/10/2022	10	0.000%	0.0000
4000464363	28084	15,770	5/31/2022	6/10/2022	10	0.004%	0.0004
4000464311	9891	1,008	5/31/2022	6/10/2022	10	0.000%	0.0000
4000464317	107767	1,000	5/31/2022	6/10/2022	10	0.000%	0.0000
4000464528	18267	1,582	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464538	34064	598	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464542	105195	16,149	6/3/2022	6/13/2022	10	0.004%	0.0004
4000464495	34888	206	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464497	105195	6,413	6/3/2022	6/13/2022	10	0.002%	0.0002
4000464498	108092	1,030	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464499	112215	664	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464500	116332	367,050	6/3/2022	6/13/2022	10	0.097%	0.0097
4000464501	125742	6,400	6/3/2022	6/13/2022	10	0.002%	0.0002
4000464503	135488	35,920	6/3/2022	6/13/2022	10	0.009%	0.0009
4000464506	139713	55,575	6/3/2022	6/13/2022	10	0.015%	0.0015
4000464509	142635	49,224	6/3/2022	6/13/2022	10	0.013%	0.0013
4000464511	143072	1,895	6/3/2022	6/13/2022	10	0.000%	0.0000
4000464512	143340	64,980	6/3/2022	6/13/2022	10	0.017%	0.0017
4000464513	143485	139,545	6/3/2022	6/13/2022	10	0.037%	0.0037
4000464515	144084	25,995	6/3/2022	6/13/2022	10	0.007%	0.0007
4000464516	144270	24,390	6/3/2022	6/13/2022	10	0.006%	0.0006
4000464519	144567	24,000	6/3/2022	6/13/2022	10	0.006%	0.0006
4000464521	144955	9,090	6/3/2022	6/13/2022	10	0.002%	0.0002
4000464553	9673	4,000	6/6/2022	6/16/2022	10	0.001%	0.0001
4000464554	10384	850	6/6/2022	6/16/2022	10	0.000%	0.0000
4000464555	11054	12,245	6/6/2022	6/16/2022	10	0.003%	0.0003
4000464572	106699	1,800	6/6/2022	6/16/2022	10	0.000%	0.0000
4000464552	145028	15,000	6/6/2022	6/16/2022	10	0.004%	0.0004
4000464609	33747	420	6/7/2022	6/17/2022	10	0.000%	0.0000
4000464610	137825	349	6/7/2022	6/17/2022	10	0.000%	0.0000
4000464580	104872	1,033	6/7/2022	6/17/2022	10	0.000%	0.0000
4000464755	11054	6,917	6/13/2022	6/23/2022	10	0.002%	0.0002
4000464756	13534	30,016	6/13/2022	6/23/2022	10	0.008%	0.0008
4000464757	13911	1,100	6/13/2022	6/23/2022	10	0.000%	0.0000
4000464760	24251	1,140	6/13/2022	6/23/2022	10	0.000%	0.0000
4000464761	24259	514	6/13/2022	6/23/2022	10	0.000%	0.0000
4000464766	25379	3,875	6/13/2022	6/23/2022	10	0.001%	0.0001
4000464769	26297	16,077	6/13/2022	6/23/2022	10	0.004%	0.0004
4000464778	26674	3,080	6/13/2022	6/23/2022	10	0.001%	0.0001
4000464784	117331	3,300	6/13/2022	6/23/2022	10	0.001%	0.0001
4000464743	28084	7,030	6/13/2022	6/23/2022	10	0.002%	0.0002
4000464748	143340	275,201	6/13/2022	6/23/2022	10	0.073%	0.0073
4000464806	8392	32,903	6/14/2022	6/24/2022	10	0.009%	0.0009
4000464810	18267	2,230	6/14/2022	6/24/2022	10	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464811	25809	351	6/14/2022	6/24/2022	10	0.000%	0.0000
4000464812	27013	15,297	6/14/2022	6/24/2022	10	0.004%	0.0004
4000464813	27994	11,275	6/14/2022	6/24/2022	10	0.003%	0.0003
4000464817	130375	19,065	6/14/2022	6/24/2022	10	0.005%	0.0005
4000464790	105195	1,783	6/14/2022	6/24/2022	10	0.000%	0.0000
4000464796	129859	30,325	6/14/2022	6/24/2022	10	0.008%	0.0008
4000464907	108092	3,204	6/17/2022	6/27/2022	10	0.001%	0.0001
4000464908	112215	3,432	6/17/2022	6/27/2022	10	0.001%	0.0001
4000464913	125742	10,844	6/17/2022	6/27/2022	10	0.003%	0.0003
4000464918	138494	3,080	6/17/2022	6/27/2022	10	0.001%	0.0001
4000464920	139713	38,595	6/17/2022	6/27/2022	10	0.010%	0.0010
4000464927	144270	87,910	6/17/2022	6/27/2022	10	0.023%	0.0023
4000464990	9673	23,325	6/20/2022	6/30/2022	10	0.006%	0.0006
4000464991	25599	10,003	6/20/2022	6/30/2022	10	0.003%	0.0003
4000464993	26490	1,623	6/20/2022	6/30/2022	10	0.000%	0.0000
4000464981	105097	500	6/20/2022	6/30/2022	10	0.000%	0.0000
4000464985	126791	3,000	6/20/2022	6/30/2022	10	0.001%	0.0001
4000465016	26363	1,178	6/21/2022	7/1/2022	10	0.000%	0.0000
4000465211	24259	1,028	6/27/2022	7/7/2022	10	0.000%	0.0000
4000465178	100400	46,000	6/27/2022	7/7/2022	10	0.012%	0.0012
4000465180	103392	15	6/27/2022	7/7/2022	10	0.000%	0.0000
4000465186	123883	25,000	6/27/2022	7/7/2022	10	0.007%	0.0007
4000465189	126928	173	6/27/2022	7/7/2022	10	0.000%	0.0000
4000465195	143497	1,000	6/27/2022	7/7/2022	10	0.000%	0.0000
4000465198	145202	2,000	6/27/2022	7/7/2022	10	0.001%	0.0001
4000465234	35151	2,250	6/28/2022	7/8/2022	10	0.001%	0.0001
4000465237	106674	30,967	6/28/2022	7/8/2022	10	0.008%	0.0008
4000465244	126928	32	6/28/2022	7/8/2022	10	0.000%	0.0000
4000465400	112215	970	7/1/2022	7/11/2022	10	0.000%	0.0000
4000465402	116332	82,004	7/1/2022	7/11/2022	10	0.022%	0.0022
4000465404	121825	5,999	7/1/2022	7/11/2022	10	0.002%	0.0002
4000465405	125742	25,059	7/1/2022	7/11/2022	10	0.007%	0.0007
4000465420	144270	55,707	7/1/2022	7/11/2022	10	0.015%	0.0015
4000465487	27162	7,157	7/5/2022	7/15/2022	10	0.002%	0.0002
4000465600	18267	5,807	7/8/2022	7/18/2022	10	0.002%	0.0002
4000465602	24281	23,409	7/8/2022	7/18/2022	10	0.006%	0.0006
4000465607	26207	7,325	7/8/2022	7/18/2022	10	0.002%	0.0002
4000465611	26604	13,975	7/8/2022	7/18/2022	10	0.004%	0.0004
4000465622	33956	1,585	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465623	34064	416	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465565	4765	16,970	7/8/2022	7/18/2022	10	0.004%	0.0004
4000465567	20287	344	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465569	34888	22	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465570	104496	29	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465571	105195	15,965	7/8/2022	7/18/2022	10	0.004%	0.0004
4000465573	113448	27,951	7/8/2022	7/18/2022	10	0.007%	0.0007
4000465574	121825	35,997	7/8/2022	7/18/2022	10	0.009%	0.0009
4000465575	125742	24,080	7/8/2022	7/18/2022	10	0.006%	0.0006
4000465577	138494	5,100	7/8/2022	7/18/2022	10	0.001%	0.0001
4000465578	141114	16,824	7/8/2022	7/18/2022	10	0.004%	0.0004
4000465580	142635	46,880	7/8/2022	7/18/2022	10	0.012%	0.0012
4000465581	142700	3,030	7/8/2022	7/18/2022	10	0.001%	0.0001
4000465583	143072	8,010	7/8/2022	7/18/2022	10	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465585	143659	1,730	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465586	143796	72,563	7/8/2022	7/18/2022	10	0.019%	0.0019
4000465587	144270	1,139	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465589	144480	14,525	7/8/2022	7/18/2022	10	0.004%	0.0004
4000465590	144567	9,433	7/8/2022	7/18/2022	10	0.002%	0.0002
4000465592	145137	1,700	7/8/2022	7/18/2022	10	0.000%	0.0000
4000465655	28348	920	7/11/2022	7/21/2022	10	0.000%	0.0000
4000465656	28530	23,047	7/11/2022	7/21/2022	10	0.006%	0.0006
4000465725	8392	16,508	7/12/2022	7/22/2022	10	0.004%	0.0004
4000465861	33956	4,055	7/15/2022	7/25/2022	10	0.001%	0.0001
4000465862	34064	464	7/15/2022	7/25/2022	10	0.000%	0.0000
4000465819	121825	11,999	7/15/2022	7/25/2022	10	0.003%	0.0003
4000465820	125742	198	7/15/2022	7/25/2022	10	0.000%	0.0000
4000465822	137204	16,197	7/15/2022	7/25/2022	10	0.004%	0.0004
4000465824	138494	3,400	7/15/2022	7/25/2022	10	0.001%	0.0001
4000465831	143312	26,298	7/15/2022	7/25/2022	10	0.007%	0.0007
4000465833	143584	6,090	7/15/2022	7/25/2022	10	0.002%	0.0002
4000465834	143588	10,938	7/15/2022	7/25/2022	10	0.003%	0.0003
4000465835	143920	13	7/15/2022	7/25/2022	10	0.000%	0.0000
4000465837	144270	25,317	7/15/2022	7/25/2022	10	0.007%	0.0007
4000465838	144567	15,275	7/15/2022	7/25/2022	10	0.004%	0.0004
4000465839	144567	12,574	7/15/2022	7/25/2022	10	0.003%	0.0003
4000465840	145137	850	7/15/2022	7/25/2022	10	0.000%	0.0000
4000465884	24383	1,988	7/18/2022	7/28/2022	10	0.001%	0.0001
4000465888	27389	7,993	7/18/2022	7/28/2022	10	0.002%	0.0002
4000465871	133437	10,000	7/18/2022	7/28/2022	10	0.003%	0.0003
4000465906	24113	4,834	7/19/2022	7/29/2022	10	0.001%	0.0001
4000465892	116384	260	7/19/2022	7/29/2022	10	0.000%	0.0000
4000466028	112215	11,031	7/22/2022	8/1/2022	10	0.003%	0.0003
4000466029	116384	168	7/22/2022	8/1/2022	10	0.000%	0.0000
4000466030	121825	65,994	7/22/2022	8/1/2022	10	0.017%	0.0017
4000466032	125742	63,669	7/22/2022	8/1/2022	10	0.017%	0.0017
4000466036	138494	1,700	7/22/2022	8/1/2022	10	0.000%	0.0000
4000466038	142700	21,212	7/22/2022	8/1/2022	10	0.006%	0.0006
4000466042	143072	3,043	7/22/2022	8/1/2022	10	0.001%	0.0001
4000466045	144097	940,744	7/22/2022	8/1/2022	10	0.248%	0.0248
4000466046	144270	8,305	7/22/2022	8/1/2022	10	0.002%	0.0002
4000466050	145139	170,000	7/22/2022	8/1/2022	10	0.045%	0.0045
4000466097	24259	1,739	7/25/2022	8/4/2022	10	0.000%	0.0000
4000466101	25599	1,465	7/25/2022	8/4/2022	10	0.000%	0.0000
4000466102	26297	8,743	7/25/2022	8/4/2022	10	0.002%	0.0002
4000466086	6396	8,921	7/25/2022	8/4/2022	10	0.002%	0.0002
4000466165	134272	96,331	7/26/2022	8/5/2022	10	0.025%	0.0025
4000466116	131647	2,338	7/26/2022	8/5/2022	10	0.001%	0.0001
4000466121	141021	2,700	7/26/2022	8/5/2022	10	0.001%	0.0001
4000466122	141370	13,250	7/26/2022	8/5/2022	10	0.003%	0.0003
4000466125	142002	7,696	7/26/2022	8/5/2022	10	0.002%	0.0002
4000466137	143807	1,058	7/26/2022	8/5/2022	10	0.000%	0.0000
4000466142	144410	2,850	7/26/2022	8/5/2022	10	0.001%	0.0001
4000466150	144927	6,000	7/26/2022	8/5/2022	10	0.002%	0.0002
4000466272	125742	5,397	7/29/2022	8/8/2022	10	0.001%	0.0001
4000466274	133414	12,077	7/29/2022	8/8/2022	10	0.003%	0.0003
4000466289	144949	64	7/29/2022	8/8/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466366	4263	4,800	8/1/2022	8/11/2022	10	0.001%	0.0001
4000466367	9673	525	8/1/2022	8/11/2022	10	0.000%	0.0000
4000466371	11426	620	8/1/2022	8/11/2022	10	0.000%	0.0000
4000466377	26213	6,394	8/1/2022	8/11/2022	10	0.002%	0.0002
4000466385	28084	2,850	8/1/2022	8/11/2022	10	0.001%	0.0001
4000466386	28737	14,350	8/1/2022	8/11/2022	10	0.004%	0.0004
4000466390	134272	73,657	8/1/2022	8/11/2022	10	0.019%	0.0019
4000466357	143880	1,800	8/1/2022	8/11/2022	10	0.000%	0.0000
4000466360	144986	4,000	8/1/2022	8/11/2022	10	0.001%	0.0001
4000466361	145028	15,000	8/1/2022	8/11/2022	10	0.004%	0.0004
4000466365	145239	11,899	8/1/2022	8/11/2022	10	0.003%	0.0003
4000466393	32922	1,059	8/1/2022	8/11/2022	10	0.000%	0.0000
4000466408	33032	1,357	8/1/2022	8/11/2022	10	0.000%	0.0000
4000466414	33069	240,673	8/1/2022	8/11/2022	10	0.063%	0.0063
4000466415	33096	18,772	8/1/2022	8/11/2022	10	0.005%	0.0005
4000466433	26588	29,230	8/2/2022	8/12/2022	10	0.008%	0.0008
4000466564	18518	6,600	8/5/2022	8/15/2022	10	0.002%	0.0002
4000466537	125742	22,762	8/5/2022	8/15/2022	10	0.006%	0.0006
4000466543	142635	57,238	8/5/2022	8/15/2022	10	0.015%	0.0015
4000466545	142700	9,091	8/5/2022	8/15/2022	10	0.002%	0.0002
4000466547	143072	13,406	8/5/2022	8/15/2022	10	0.004%	0.0004
4000466556	144097	100,000	8/5/2022	8/15/2022	10	0.026%	0.0026
4000466557	144480	36,313	8/5/2022	8/15/2022	10	0.010%	0.0010
4000466595	24281	5,448	8/8/2022	8/18/2022	10	0.001%	0.0001
4000466603	26490	1,267	8/8/2022	8/18/2022	10	0.000%	0.0000
4000466608	26679	3,625	8/8/2022	8/18/2022	10	0.001%	0.0001
4000466613	130375	1,206	8/8/2022	8/18/2022	10	0.000%	0.0000
4000466636	11304	4,500	8/9/2022	8/19/2022	10	0.001%	0.0001
4000466618	103392	885	8/9/2022	8/19/2022	10	0.000%	0.0000
4000466619	103471	33	8/9/2022	8/19/2022	10	0.000%	0.0000
4000466814	34335	450	8/12/2022	8/22/2022	10	0.000%	0.0000
4000466817	34658	3,700	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466820	133795	11,499	8/12/2022	8/22/2022	10	0.003%	0.0003
4000466780	112215	3,460	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466782	116384	668	8/12/2022	8/22/2022	10	0.000%	0.0000
4000466785	125742	2,056	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466788	138494	18,010	8/12/2022	8/22/2022	10	0.005%	0.0005
4000466789	141114	5,285	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466792	143072	7,321	8/12/2022	8/22/2022	10	0.002%	0.0002
4000466794	143154	1,602	8/12/2022	8/22/2022	10	0.000%	0.0000
4000466798	143485	139,545	8/12/2022	8/22/2022	10	0.037%	0.0037
4000466799	143577	4,613	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466803	144583	35,800	8/12/2022	8/22/2022	10	0.009%	0.0009
4000466805	145194	2,150	8/12/2022	8/22/2022	10	0.001%	0.0001
4000466841	25808	720	8/15/2022	8/25/2022	10	0.000%	0.0000
4000466844	26604	69,445	8/15/2022	8/25/2022	10	0.018%	0.0018
4000466846	27013	3,570	8/15/2022	8/25/2022	10	0.001%	0.0001
4000466847	28084	4,845	8/15/2022	8/25/2022	10	0.001%	0.0001
4000466849	32538	237	8/15/2022	8/25/2022	10	0.000%	0.0000
4000466852	126165	25,201	8/15/2022	8/25/2022	10	0.007%	0.0007
4000466824	24765	37,557	8/15/2022	8/25/2022	10	0.010%	0.0010
4000466833	143072	3,612	8/15/2022	8/25/2022	10	0.001%	0.0001
4000466834	145254	11,809	8/15/2022	8/25/2022	10	0.003%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466886	11536	5,675	8/16/2022	8/26/2022	10	0.001%	0.0001
4000466865	108149	115	8/16/2022	8/26/2022	10	0.000%	0.0000
4000466868	116902	26,783	8/16/2022	8/26/2022	10	0.007%	0.0007
4000466869	116902	15,764	8/16/2022	8/26/2022	10	0.004%	0.0004
4000467030	117331	20,812	8/19/2022	8/29/2022	10	0.005%	0.0005
4000466985	110291	511	8/19/2022	8/29/2022	10	0.000%	0.0000
4000466987	121825	35,997	8/19/2022	8/29/2022	10	0.009%	0.0009
4000466989	125742	26,645	8/19/2022	8/29/2022	10	0.007%	0.0007
4000466996	142700	18,181	8/19/2022	8/29/2022	10	0.005%	0.0005
4000466998	143072	2,111	8/19/2022	8/29/2022	10	0.001%	0.0001
4000467002	143573	1,205,735	8/19/2022	8/29/2022	10	0.318%	0.0318
4000467003	143577	7,399	8/19/2022	8/29/2022	10	0.002%	0.0002
4000467033	32938	4,106	8/19/2022	8/29/2022	10	0.001%	0.0001
4000467047	33016	95,102	8/19/2022	8/29/2022	10	0.025%	0.0025
4000467057	33126	162,479	8/19/2022	8/29/2022	10	0.043%	0.0043
4000467083	26604	25,325	8/22/2022	9/1/2022	10	0.007%	0.0007
4000467059	6396	16,990	8/22/2022	9/1/2022	10	0.004%	0.0004
4000467060	32869	19,269	8/22/2022	9/1/2022	10	0.005%	0.0005
4000467065	104872	474	8/22/2022	9/1/2022	10	0.000%	0.0000
4000467066	107450	3,000	8/22/2022	9/1/2022	10	0.001%	0.0001
4000467070	122107	500	8/22/2022	9/1/2022	10	0.000%	0.0000
4000467074	142164	5,356	8/22/2022	9/1/2022	10	0.001%	0.0001
4000467075	142164	17,554	8/22/2022	9/1/2022	10	0.005%	0.0005
4000467106	27013	8,650	8/23/2022	9/2/2022	10	0.002%	0.0002
4000467283	32808	990	8/29/2022	9/8/2022	10	0.000%	0.0000
4000467285	33203	31,625	8/29/2022	9/8/2022	10	0.008%	0.0008
4000467286	34937	12,000	8/29/2022	9/8/2022	10	0.003%	0.0003
4000467273	123377	2,508	8/29/2022	9/8/2022	10	0.001%	0.0001
4000467276	144119	3,600	8/29/2022	9/8/2022	10	0.001%	0.0001
4000467277	144460	1,100	8/29/2022	9/8/2022	10	0.000%	0.0000
4000467279	144567	200	8/29/2022	9/8/2022	10	0.000%	0.0000
4000467316	9673	11,450	8/30/2022	9/9/2022	10	0.003%	0.0003
4000467323	26643	16,937	8/30/2022	9/9/2022	10	0.004%	0.0004
4000467328	34531	2,640	8/30/2022	9/9/2022	10	0.001%	0.0001
4000467290	35151	2,250	8/30/2022	9/9/2022	10	0.001%	0.0001
4000467447	126711	7,686	9/2/2022	9/12/2022	10	0.002%	0.0002
4000467465	125742	6,441	9/2/2022	9/12/2022	10	0.002%	0.0002
4000467478	141822	8,480	9/2/2022	9/12/2022	10	0.002%	0.0002
4000467482	142635	25,592	9/2/2022	9/12/2022	10	0.007%	0.0007
4000467503	144583	9,900	9/2/2022	9/12/2022	10	0.003%	0.0003
4000467668	133795	11,499	9/9/2022	9/19/2022	10	0.003%	0.0003
4000467628	125742	21,760	9/9/2022	9/19/2022	10	0.006%	0.0006
4000467631	138494	102,000	9/9/2022	9/19/2022	10	0.027%	0.0027
4000467632	142613	18,930	9/9/2022	9/19/2022	10	0.005%	0.0005
4000467633	142635	43,280	9/9/2022	9/19/2022	10	0.011%	0.0011
4000467643	144097	535,792	9/9/2022	9/19/2022	10	0.141%	0.0141
4000467684	26679	4,813	9/12/2022	9/22/2022	10	0.001%	0.0001
4000467669	103392	27	9/12/2022	9/22/2022	10	0.000%	0.0000
4000467670	107047	22,924	9/12/2022	9/22/2022	10	0.006%	0.0006
4000467674	134072	10,500	9/12/2022	9/22/2022	10	0.003%	0.0003
4000467678	143072	30,395	9/12/2022	9/22/2022	10	0.008%	0.0008
4000467682	144530	10,698	9/12/2022	9/22/2022	10	0.003%	0.0003
4000467707	27068	6,555	9/13/2022	9/23/2022	10	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467842	110291	1,235	9/16/2022	9/26/2022	10	0.000%	0.0000
4000467847	125742	3,172	9/16/2022	9/26/2022	10	0.001%	0.0001
4000467848	133414	118	9/16/2022	9/26/2022	10	0.000%	0.0000
4000467850	138494	30,528	9/16/2022	9/26/2022	10	0.008%	0.0008
4000467853	142926	57,208	9/16/2022	9/26/2022	10	0.015%	0.0015
4000467855	143072	52,336	9/16/2022	9/26/2022	10	0.014%	0.0014
4000467857	143577	3,435	9/16/2022	9/26/2022	10	0.001%	0.0001
4000467900	11054	3,734	9/19/2022	9/29/2022	10	0.001%	0.0001
4000467901	11372	471	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467902	11536	89,355	9/19/2022	9/29/2022	10	0.024%	0.0024
4000467906	27013	9,278	9/19/2022	9/29/2022	10	0.002%	0.0002
4000467907	27982	1,695	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467908	27994	1,430	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467911	33747	840	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467887	10439	935	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467888	26130	11,178	9/19/2022	9/29/2022	10	0.003%	0.0003
4000467894	138862	50	9/19/2022	9/29/2022	10	0.000%	0.0000
4000467943	26639	4,523	9/20/2022	9/30/2022	10	0.001%	0.0001
4000467947	34972	56,650	9/20/2022	9/30/2022	10	0.015%	0.0015
4000467920	125789	1,080	9/20/2022	9/30/2022	10	0.000%	0.0000
4000468035	100577	27	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468040	110291	43,043	9/23/2022	10/3/2022	10	0.011%	0.0011
4000468041	110291	32,263	9/23/2022	10/3/2022	10	0.009%	0.0009
4000468042	110291	16,856	9/23/2022	10/3/2022	10	0.004%	0.0004
4000468043	113563	385	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468045	116384	905	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468047	125742	19,746	9/23/2022	10/3/2022	10	0.005%	0.0005
4000468049	129855	1,342	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468053	137204	2,446	9/23/2022	10/3/2022	10	0.001%	0.0001
4000468057	141552	16,916	9/23/2022	10/3/2022	10	0.004%	0.0004
4000468058	142587	2,516	9/23/2022	10/3/2022	10	0.001%	0.0001
4000468059	142926	1,601	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468061	143072	12,463	9/23/2022	10/3/2022	10	0.003%	0.0003
4000468064	143588	12,775	9/23/2022	10/3/2022	10	0.003%	0.0003
4000468065	144381	1,400	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468067	145170	1,032	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468069	145212	5,259	9/23/2022	10/3/2022	10	0.001%	0.0001
4000468070	145377	277	9/23/2022	10/3/2022	10	0.000%	0.0000
4000468118	25708	2,351	9/26/2022	10/6/2022	10	0.001%	0.0001
4000468120	26490	4,561	9/26/2022	10/6/2022	10	0.001%	0.0001
4000468124	30475	12,857	9/26/2022	10/6/2022	10	0.003%	0.0003
4000468125	32808	1,760	9/26/2022	10/6/2022	10	0.000%	0.0000
4000468126	34173	11,592	9/26/2022	10/6/2022	10	0.003%	0.0003
4000468097	9673	2,050	9/26/2022	10/6/2022	10	0.001%	0.0001
4000468100	107047	20,108	9/26/2022	10/6/2022	10	0.005%	0.0005
4000468105	135441	5,000	9/26/2022	10/6/2022	10	0.001%	0.0001
4000468114	144381	5,600	9/26/2022	10/6/2022	10	0.001%	0.0001
4000468170	33017	6,413	9/27/2022	10/7/2022	10	0.002%	0.0002
4000468173	33039	4,950	9/27/2022	10/7/2022	10	0.001%	0.0001
4000468175	33060	5,500	9/27/2022	10/7/2022	10	0.001%	0.0001
4000468182	33103	5,563	9/27/2022	10/7/2022	10	0.001%	0.0001
4000468185	33116	3,597	9/27/2022	10/7/2022	10	0.001%	0.0001
4000468191	33152	4,876	9/27/2022	10/7/2022	10	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468447	17342	945	10/3/2022	10/13/2022	10	0.000%	0.0000
4000468450	24259	11,499	10/3/2022	10/13/2022	10	0.003%	0.0003
4000468453	26297	55,166	10/3/2022	10/13/2022	10	0.015%	0.0015
4000468458	26490	2,027	10/3/2022	10/13/2022	10	0.001%	0.0001
4000468459	26639	540	10/3/2022	10/13/2022	10	0.000%	0.0000
4000468468	126165	1,320	10/3/2022	10/13/2022	10	0.000%	0.0000
4000468426	26130	182,807	10/3/2022	10/13/2022	10	0.048%	0.0048
4000468438	144986	4,000	10/3/2022	10/13/2022	10	0.001%	0.0001
4000468441	145067	2,200	10/3/2022	10/13/2022	10	0.001%	0.0001
4000468479	9673	1,850	10/4/2022	10/14/2022	10	0.000%	0.0000
4000468481	26604	7,470	10/4/2022	10/14/2022	10	0.002%	0.0002
4000468482	27013	13,414	10/4/2022	10/14/2022	10	0.004%	0.0004
4000468569	143694	5,800	10/7/2022	10/17/2022	10	0.002%	0.0002
4000468652	26490	7,471	10/11/2022	10/21/2022	10	0.002%	0.0002
4000468660	27068	14,421	10/11/2022	10/21/2022	10	0.004%	0.0004
4000468665	30365	2,010	10/11/2022	10/21/2022	10	0.001%	0.0001
4000468666	32875	3,400	10/11/2022	10/21/2022	10	0.001%	0.0001
4000468668	34531	39,224	10/11/2022	10/21/2022	10	0.010%	0.0010
4000468618	26130	7,218	10/11/2022	10/21/2022	10	0.002%	0.0002
4000468621	102473	63,394	10/11/2022	10/21/2022	10	0.017%	0.0017
4000468623	103471	112	10/11/2022	10/21/2022	10	0.000%	0.0000
4000468627	126047	26,434	10/11/2022	10/21/2022	10	0.007%	0.0007
4000468637	144581	966	10/11/2022	10/21/2022	10	0.000%	0.0000
4000468638	144794	5,600	10/11/2022	10/21/2022	10	0.001%	0.0001
4000468841	34335	150	10/14/2022	10/24/2022	10	0.000%	0.0000
4000468842	34341	1,325	10/14/2022	10/24/2022	10	0.000%	0.0000
4000468843	34389	5,000	10/14/2022	10/24/2022	10	0.001%	0.0001
4000468792	36403	3,866	10/14/2022	10/24/2022	10	0.001%	0.0001
4000468795	108092	22,080	10/14/2022	10/24/2022	10	0.006%	0.0006
4000468796	110291	44,152	10/14/2022	10/24/2022	10	0.012%	0.0012
4000468797	110291	15,046	10/14/2022	10/24/2022	10	0.004%	0.0004
4000468798	133414	1,717	10/14/2022	10/24/2022	10	0.000%	0.0000
4000468801	141552	3,754	10/14/2022	10/24/2022	10	0.001%	0.0001
4000468802	142635	8,249	10/14/2022	10/24/2022	10	0.002%	0.0002
4000468810	143338	112,880	10/14/2022	10/24/2022	10	0.030%	0.0030
4000468871	9673	17,600	10/17/2022	10/27/2022	10	0.005%	0.0005
4000468872	11054	1,344	10/17/2022	10/27/2022	10	0.000%	0.0000
4000468880	25987	900	10/17/2022	10/27/2022	10	0.000%	0.0000
4000468882	26363	1,970	10/17/2022	10/27/2022	10	0.001%	0.0001
4000468883	26604	8,700	10/17/2022	10/27/2022	10	0.002%	0.0002
4000468884	26639	5,738	10/17/2022	10/27/2022	10	0.002%	0.0002
4000468888	28530	39,473	10/17/2022	10/27/2022	10	0.010%	0.0010
4000468892	106699	6,188	10/17/2022	10/27/2022	10	0.002%	0.0002
4000468851	24765	34,908	10/17/2022	10/27/2022	10	0.009%	0.0009
4000468856	114571	2,000	10/17/2022	10/27/2022	10	0.001%	0.0001
4000468858	116518	25,000	10/17/2022	10/27/2022	10	0.007%	0.0007
4000468914	141583	129	10/18/2022	10/28/2022	10	0.000%	0.0000
4000468896	111823	16,483	10/18/2022	10/28/2022	10	0.004%	0.0004
4000469083	104509	2,082	10/21/2022	10/31/2022	10	0.001%	0.0001
4000469085	112215	21,891	10/21/2022	10/31/2022	10	0.006%	0.0006
4000469086	116384	289	10/21/2022	10/31/2022	10	0.000%	0.0000
4000469087	121825	61,680	10/21/2022	10/31/2022	10	0.016%	0.0016
4000469089	125742	4,200	10/21/2022	10/31/2022	10	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469091	129859	2,124,758	10/21/2022	10/31/2022	10	0.560%	0.0560
4000469095	141256	7	10/21/2022	10/31/2022	10	0.000%	0.0000
4000469100	143072	5,641	10/21/2022	10/31/2022	10	0.001%	0.0001
4000469141	118807	2,492	10/24/2022	11/3/2022	10	0.001%	0.0001
4000469143	133057	1,200	10/24/2022	11/3/2022	10	0.000%	0.0000
4000469144	133102	500	10/24/2022	11/3/2022	10	0.000%	0.0000
4000469145	141203	237,008	10/24/2022	11/3/2022	10	0.063%	0.0063
4000469187	8392	22,203	10/25/2022	11/4/2022	10	0.006%	0.0006
4000469189	9673	525	10/25/2022	11/4/2022	10	0.000%	0.0000
4000469193	24113	2,863	10/25/2022	11/4/2022	10	0.001%	0.0001
4000469194	24211	3,434	10/25/2022	11/4/2022	10	0.001%	0.0001
4000469170	108289	142	10/25/2022	11/4/2022	10	0.000%	0.0000
4000469172	116384	18	10/25/2022	11/4/2022	10	0.000%	0.0000
4000469173	116902	40,100	10/25/2022	11/4/2022	10	0.011%	0.0011
4000469177	135057	2,526	10/25/2022	11/4/2022	10	0.001%	0.0001
4000469205	33118	1,282	10/25/2022	11/4/2022	10	0.000%	0.0000
4000469346	137204	2,232	10/28/2022	11/7/2022	10	0.001%	0.0001
4000469350	143072	82,346	10/28/2022	11/7/2022	10	0.022%	0.0022
4000469432	11054	6,412	10/31/2022	11/10/2022	10	0.002%	0.0002
4000469433	11372	9,251	10/31/2022	11/10/2022	10	0.002%	0.0002
4000469434	11474	1,750	10/31/2022	11/10/2022	10	0.000%	0.0000
4000469443	27994	15,895	10/31/2022	11/10/2022	10	0.004%	0.0004
4000469445	28530	35,880	10/31/2022	11/10/2022	10	0.009%	0.0009
4000469405	22798	38,022	10/31/2022	11/10/2022	10	0.010%	0.0010
4000469410	104872	1,398	10/31/2022	11/10/2022	10	0.000%	0.0000
4000469419	134862	316,027	10/31/2022	11/10/2022	10	0.083%	0.0083
4000469611	100577	170	11/4/2022	11/14/2022	10	0.000%	0.0000
4000469615	108092	9,840	11/4/2022	11/14/2022	10	0.003%	0.0003
4000469616	110291	8,340	11/4/2022	11/14/2022	10	0.002%	0.0002
4000469618	125742	15,109	11/4/2022	11/14/2022	10	0.004%	0.0004
4000469622	138494	32,000	11/4/2022	11/14/2022	10	0.008%	0.0008
4000469623	139713	38,595	11/4/2022	11/14/2022	10	0.010%	0.0010
4000469625	142926	116,844	11/4/2022	11/14/2022	10	0.031%	0.0031
4000469681	25272	13,908	11/7/2022	11/17/2022	10	0.004%	0.0004
4000469675	143741	500	11/7/2022	11/17/2022	10	0.000%	0.0000
4000469690	104872	30	11/8/2022	11/18/2022	10	0.000%	0.0000
4000469896	27962	2,963	11/15/2022	11/25/2022	10	0.001%	0.0001
4000470007	110291	47,230	11/18/2022	11/28/2022	10	0.012%	0.0012
4000470009	129387	32,628	11/18/2022	11/28/2022	10	0.009%	0.0009
4000470092	24825	3,499	11/21/2022	12/1/2022	10	0.001%	0.0001
4000470095	26643	421	11/21/2022	12/1/2022	10	0.000%	0.0000
4000470074	142926	4,604	11/21/2022	12/1/2022	10	0.001%	0.0001
4000470134	25131	950	11/22/2022	12/2/2022	10	0.000%	0.0000
4000470140	25987	1,000	11/22/2022	12/2/2022	10	0.000%	0.0000
4000470142	27068	13,110	11/22/2022	12/2/2022	10	0.003%	0.0003
4000470107	104872	187	11/22/2022	12/2/2022	10	0.000%	0.0000
4000470111	118807	456	11/22/2022	12/2/2022	10	0.000%	0.0000
4000470123	143659	13,295	11/22/2022	12/2/2022	10	0.004%	0.0004
4000470131	116971	3,000	11/22/2022	12/2/2022	10	0.001%	0.0001
4000470249	11054	6,289	11/28/2022	12/8/2022	10	0.002%	0.0002
4000470251	14949	951	11/28/2022	12/8/2022	10	0.000%	0.0000
4000470258	25905	700	11/28/2022	12/8/2022	10	0.000%	0.0000
4000470259	25987	400	11/28/2022	12/8/2022	10	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470260	26296	1,503	11/28/2022	12/8/2022	10	0.000%	0.0000
4000470263	26604	38,935	11/28/2022	12/8/2022	10	0.010%	0.0010
4000470265	26674	4,550	11/28/2022	12/8/2022	10	0.001%	0.0001
4000470269	27389	23,805	11/28/2022	12/8/2022	10	0.006%	0.0006
4000470270	27982	993	11/28/2022	12/8/2022	10	0.000%	0.0000
4000470245	144487	11,730	11/28/2022	12/8/2022	10	0.003%	0.0003
4000470284	116384	116	11/29/2022	12/9/2022	10	0.000%	0.0000
4000470285	142926	55,647	11/29/2022	12/9/2022	10	0.015%	0.0015
4000470450	126711	7,686	12/2/2022	12/12/2022	10	0.002%	0.0002
4000470461	112215	156	12/2/2022	12/12/2022	10	0.000%	0.0000
4000470469	138494	5,227	12/2/2022	12/12/2022	10	0.001%	0.0001
4000470472	141114	1,211	12/2/2022	12/12/2022	10	0.000%	0.0000
4000470474	141822	8,480	12/2/2022	12/12/2022	10	0.002%	0.0002
4000470481	142700	11,505	12/2/2022	12/12/2022	10	0.003%	0.0003
4000470494	143485	139,759	12/2/2022	12/12/2022	10	0.037%	0.0037
4000470569	27389	46,690	12/5/2022	12/15/2022	10	0.012%	0.0012
4000470544	104872	175	12/5/2022	12/15/2022	10	0.000%	0.0000
4000470546	118807	651	12/5/2022	12/15/2022	10	0.000%	0.0000
4000470548	126047	41,240	12/5/2022	12/15/2022	10	0.011%	0.0011
4000470558	143807	1,400	12/5/2022	12/15/2022	10	0.000%	0.0000
4000470563	145240	8,046	12/5/2022	12/15/2022	10	0.002%	0.0002
4000470579	116051	800	12/6/2022	12/16/2022	10	0.000%	0.0000
4000470585	143659	25,068	12/6/2022	12/16/2022	10	0.007%	0.0007
4000470701	125742	31,859	12/9/2022	12/19/2022	10	0.008%	0.0008
4000470704	138494	20,000	12/9/2022	12/19/2022	10	0.005%	0.0005
4000470705	142587	3,142	12/9/2022	12/19/2022	10	0.001%	0.0001
4000470706	142700	15,334	12/9/2022	12/19/2022	10	0.004%	0.0004
4000470708	143011	31,686	12/9/2022	12/19/2022	10	0.008%	0.0008
4000470709	143072	15,708	12/9/2022	12/19/2022	10	0.004%	0.0004
4000470763	10630	2,560	12/12/2022	12/22/2022	10	0.001%	0.0001
4000470768	25808	23,940	12/12/2022	12/22/2022	10	0.006%	0.0006
4000470772	26604	2,255	12/12/2022	12/22/2022	10	0.001%	0.0001
4000470776	28530	24,125	12/12/2022	12/22/2022	10	0.006%	0.0006
4000470778	34069	920	12/12/2022	12/22/2022	10	0.000%	0.0000
4000470780	126775	27,965	12/12/2022	12/22/2022	10	0.007%	0.0007
4000470751	129783	159	12/12/2022	12/22/2022	10	0.000%	0.0000
4000470756	143072	5,612	12/12/2022	12/22/2022	10	0.001%	0.0001
4000470788	142942	3,258	12/13/2022	12/23/2022	10	0.001%	0.0001
4000470790	143520	2,236	12/13/2022	12/23/2022	10	0.001%	0.0001
4000470793	144924	3,540	12/13/2022	12/23/2022	10	0.001%	0.0001
4000471043	11305	35,890	12/19/2022	12/29/2022	10	0.009%	0.0009
4000471045	17342	4,185	12/19/2022	12/29/2022	10	0.001%	0.0001
4000471030	110291	1,020	12/19/2022	12/29/2022	10	0.000%	0.0000
4000471031	116384	540	12/19/2022	12/29/2022	10	0.000%	0.0000
4000471032	117159	31,338	12/19/2022	12/29/2022	10	0.008%	0.0008
4000471036	142732	30,000	12/19/2022	12/29/2022	10	0.008%	0.0008
4000471082	10630	1,120	12/20/2022	12/30/2022	10	0.000%	0.0000
4000471085	24385	24,849	12/20/2022	12/30/2022	10	0.007%	0.0007
4000471089	25659	18,035	12/20/2022	12/30/2022	10	0.005%	0.0005
4000471097	27994	11,770	12/20/2022	12/30/2022	10	0.003%	0.0003
4000471102	32537	550	12/20/2022	12/30/2022	10	0.000%	0.0000
4000471058	103008	2,493	12/20/2022	12/30/2022	10	0.001%	0.0001
4000471060	107047	25,256	12/20/2022	12/30/2022	10	0.007%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471064	125742	26,132	12/20/2022	12/30/2022	10	0.007%	0.0007
4000471280	9673	9,725	12/27/2022	1/6/2023	10	0.003%	0.0003
4000471282	11304	4,800	12/27/2022	1/6/2023	10	0.001%	0.0001
4000471291	26338	2,193	12/27/2022	1/6/2023	10	0.001%	0.0001
4000471270	110291	1,144	12/27/2022	1/6/2023	10	0.000%	0.0000
4000471431	112215	13,520	12/30/2022	1/9/2023	10	0.004%	0.0004
4000471432	112215	14,184	12/30/2022	1/9/2023	10	0.004%	0.0004
4000459555	24251	12,840	1/3/2022	1/14/2022	11	0.003%	0.0004
4000459557	27068	21,463	1/3/2022	1/14/2022	11	0.006%	0.0006
4000459546	116384	304	1/3/2022	1/14/2022	11	0.000%	0.0000
4000459673	11305	1,180	1/7/2022	1/18/2022	11	0.000%	0.0000
4000459665	112215	11,875	1/7/2022	1/18/2022	11	0.003%	0.0003
4000459697	33770	79,267	1/10/2022	1/21/2022	11	0.021%	0.0023
4000459704	126928	139	1/10/2022	1/21/2022	11	0.000%	0.0000
4000459708	143741	950	1/10/2022	1/21/2022	11	0.000%	0.0000
4000459709	144846	39	1/10/2022	1/21/2022	11	0.000%	0.0000
4000459858	1908	18,759	1/13/2022	1/24/2022	11	0.005%	0.0005
4000459863	18267	11,853	1/13/2022	1/24/2022	11	0.003%	0.0003
4000459873	34064	143	1/13/2022	1/24/2022	11	0.000%	0.0000
4000459811	4208	80,447	1/13/2022	1/24/2022	11	0.021%	0.0023
4000459818	10055	35,806	1/13/2022	1/24/2022	11	0.009%	0.0010
4000459821	27094	80,241	1/13/2022	1/24/2022	11	0.021%	0.0023
4000459828	105195	9,313	1/13/2022	1/24/2022	11	0.002%	0.0003
4000459830	112215	106,284	1/13/2022	1/24/2022	11	0.028%	0.0031
4000459831	113563	15,241	1/13/2022	1/24/2022	11	0.004%	0.0004
4000459832	116332	517,318	1/13/2022	1/24/2022	11	0.136%	0.0150
4000459834	129855	432	1/13/2022	1/24/2022	11	0.000%	0.0000
4000459836	134862	778,668	1/13/2022	1/24/2022	11	0.205%	0.0226
4000459846	143452	21,165	1/13/2022	1/24/2022	11	0.006%	0.0006
4000459849	144084	252,107	1/13/2022	1/24/2022	11	0.066%	0.0073
4000459850	144567	4,956	1/13/2022	1/24/2022	11	0.001%	0.0001
4000459852	144663	93,450	1/13/2022	1/24/2022	11	0.025%	0.0027
4000459853	144663	93,850	1/13/2022	1/24/2022	11	0.025%	0.0027
4000459854	144663	90,150	1/13/2022	1/24/2022	11	0.024%	0.0026
4000459904	117331	8,200	1/14/2022	1/25/2022	11	0.002%	0.0002
4000459905	124943	1,140	1/14/2022	1/25/2022	11	0.000%	0.0000
4000459884	101740	15,821	1/14/2022	1/25/2022	11	0.004%	0.0005
4000459885	103392	15	1/14/2022	1/25/2022	11	0.000%	0.0000
4000459888	115761	169	1/14/2022	1/25/2022	11	0.000%	0.0000
4000459889	116384	4	1/14/2022	1/25/2022	11	0.000%	0.0000
4000459890	118807	2,645	1/14/2022	1/25/2022	11	0.001%	0.0001
4000459916	32938	4,206	1/14/2022	1/25/2022	11	0.001%	0.0001
4000459934	32968	17,194	1/14/2022	1/25/2022	11	0.005%	0.0005
4000459945	32994	1,554	1/14/2022	1/25/2022	11	0.000%	0.0000
4000459948	32998	50,797	1/14/2022	1/25/2022	11	0.013%	0.0015
4000459879	103925	6,781	1/14/2022	1/25/2022	11	0.002%	0.0002
4000460081	11577	5,303	1/20/2022	1/31/2022	11	0.001%	0.0002
4000460084	25659	1,143	1/20/2022	1/31/2022	11	0.000%	0.0000
4000460088	27982	2,000	1/20/2022	1/31/2022	11	0.001%	0.0001
4000460089	28084	1,473	1/20/2022	1/31/2022	11	0.000%	0.0000
4000460091	28737	1,000	1/20/2022	1/31/2022	11	0.000%	0.0000
4000460092	30475	25,174	1/20/2022	1/31/2022	11	0.007%	0.0007
4000460094	32808	440	1/20/2022	1/31/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460100	117331	3,000	1/20/2022	1/31/2022	11	0.001%	0.0001
4000460052	4502	2,808	1/20/2022	1/31/2022	11	0.001%	0.0001
4000460059	27466	5,948	1/20/2022	1/31/2022	11	0.002%	0.0002
4000460061	102637	119	1/20/2022	1/31/2022	11	0.000%	0.0000
4000460062	103114	943	1/20/2022	1/31/2022	11	0.000%	0.0000
4000460070	132507	3,142	1/20/2022	1/31/2022	11	0.001%	0.0001
4000460075	143941	2,163	1/20/2022	1/31/2022	11	0.001%	0.0001
4000460076	143994	13,862	1/20/2022	1/31/2022	11	0.004%	0.0004
4000460118	26356	1,190	1/21/2022	2/1/2022	11	0.000%	0.0000
4000460125	126775	1,149	1/21/2022	2/1/2022	11	0.000%	0.0000
4000460161	26643	8,924	1/24/2022	2/4/2022	11	0.002%	0.0003
4000460162	27162	1,007	1/24/2022	2/4/2022	11	0.000%	0.0000
4000460164	27636	4,100	1/24/2022	2/4/2022	11	0.001%	0.0001
4000460132	102473	1,050	1/24/2022	2/4/2022	11	0.000%	0.0000
4000460135	118807	533	1/24/2022	2/4/2022	11	0.000%	0.0000
4000460144	142926	1,678	1/24/2022	2/4/2022	11	0.000%	0.0000
4000460193	33031	51,769	1/24/2022	2/4/2022	11	0.014%	0.0015
4000460197	33037	920,670	1/24/2022	2/4/2022	11	0.243%	0.0267
4000460423	10630	2,240	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460308	4502	75,372	1/27/2022	2/7/2022	11	0.020%	0.0022
4000460349	33021	105,357	1/27/2022	2/7/2022	11	0.028%	0.0031
4000460351	33027	2,847	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460353	33038	2,438	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460354	33067	53,243	1/27/2022	2/7/2022	11	0.014%	0.0015
4000460362	33077	14,991	1/27/2022	2/7/2022	11	0.004%	0.0004
4000460363	33079	19,203	1/27/2022	2/7/2022	11	0.005%	0.0006
4000460364	33080	119,748	1/27/2022	2/7/2022	11	0.032%	0.0035
4000460366	33082	655	1/27/2022	2/7/2022	11	0.000%	0.0000
4000460369	33088	2,421	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460372	33093	132	1/27/2022	2/7/2022	11	0.000%	0.0000
4000460378	33099	29,022	1/27/2022	2/7/2022	11	0.008%	0.0008
4000460389	33115	2,153	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460402	33130	193	1/27/2022	2/7/2022	11	0.000%	0.0000
4000460404	33132	2,062	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460408	33136	2,178	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460409	33137	7,020	1/27/2022	2/7/2022	11	0.002%	0.0002
4000460410	33138	3,949	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460415	33144	29,789	1/27/2022	2/7/2022	11	0.008%	0.0009
4000460421	33152	4,845	1/27/2022	2/7/2022	11	0.001%	0.0001
4000460422	33153	12,007	1/27/2022	2/7/2022	11	0.003%	0.0003
4000460468	4861	239,219	1/28/2022	2/8/2022	11	0.063%	0.0069
4000460484	34064	251,396	1/28/2022	2/8/2022	11	0.066%	0.0073
4000460485	124943	380	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460487	126775	4,701	1/28/2022	2/8/2022	11	0.001%	0.0001
4000460451	25623	561	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460456	103230	500,000	1/28/2022	2/8/2022	11	0.132%	0.0145
4000460457	103392	14	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460460	118807	924	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460463	143312	21,169	1/28/2022	2/8/2022	11	0.006%	0.0006
4000460498	33072	46,050	1/28/2022	2/8/2022	11	0.012%	0.0013
4000460501	33076	39,642	1/28/2022	2/8/2022	11	0.010%	0.0012
4000460523	33107	11,688	1/28/2022	2/8/2022	11	0.003%	0.0003
4000460537	33126	77,400	1/28/2022	2/8/2022	11	0.020%	0.0022

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460550	33139	29,678	1/28/2022	2/8/2022	11	0.008%	0.0009
4000460551	33140	21,878	1/28/2022	2/8/2022	11	0.006%	0.0006
4000460553	33142	9,131	1/28/2022	2/8/2022	11	0.002%	0.0003
4000460555	33145	1,567	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460557	33147	38	1/28/2022	2/8/2022	11	0.000%	0.0000
4000460559	33150	33,324	1/28/2022	2/8/2022	11	0.009%	0.0010
4000460583	9891	11,871	1/31/2022	2/11/2022	11	0.003%	0.0003
4000460605	26490	1,584	1/31/2022	2/11/2022	11	0.000%	0.0000
4000460613	34531	6,544	1/31/2022	2/11/2022	11	0.002%	0.0002
4000460572	124628	5,279	1/31/2022	2/11/2022	11	0.001%	0.0002
4000460580	143892	2,000	1/31/2022	2/11/2022	11	0.001%	0.0001
4000460581	144581	1,208	1/31/2022	2/11/2022	11	0.000%	0.0000
4000460616	33006	306,227	1/31/2022	2/11/2022	11	0.081%	0.0089
4000460738	8392	2,170	2/3/2022	2/14/2022	11	0.001%	0.0001
4000460741	11372	3,899	2/3/2022	2/14/2022	11	0.001%	0.0001
4000460744	25808	1,620	2/3/2022	2/14/2022	11	0.000%	0.0000
4000460754	27994	8,855	2/3/2022	2/14/2022	11	0.002%	0.0003
4000460736	143400	3,000	2/3/2022	2/14/2022	11	0.001%	0.0001
4000460792	24281	7,168	2/4/2022	2/15/2022	11	0.002%	0.0002
4000460795	27013	5,333	2/4/2022	2/15/2022	11	0.001%	0.0002
4000460763	15871	3,595	2/4/2022	2/15/2022	11	0.001%	0.0001
4000460769	112103	9,495	2/4/2022	2/15/2022	11	0.003%	0.0003
4000460771	116384	173	2/4/2022	2/15/2022	11	0.000%	0.0000
4000460778	135488	19,120	2/4/2022	2/15/2022	11	0.005%	0.0006
4000460782	143944	7,272	2/4/2022	2/15/2022	11	0.002%	0.0002
4000460826	8392	5,867	2/7/2022	2/18/2022	11	0.002%	0.0002
4000460842	26643	4,092	2/7/2022	2/18/2022	11	0.001%	0.0001
4000461042	34341	12,600	2/11/2022	2/22/2022	11	0.003%	0.0004
4000461045	133795	11,499	2/11/2022	2/22/2022	11	0.003%	0.0003
4000461005	112215	22,300	2/11/2022	2/22/2022	11	0.006%	0.0006
4000461006	116332	2,300	2/11/2022	2/22/2022	11	0.001%	0.0001
4000461007	116384	1,688	2/11/2022	2/22/2022	11	0.000%	0.0000
4000461009	125742	8,020	2/11/2022	2/22/2022	11	0.002%	0.0002
4000461015	132422	1,734	2/11/2022	2/22/2022	11	0.000%	0.0001
4000461021	142635	48,427	2/11/2022	2/22/2022	11	0.013%	0.0014
4000460982	144920	250	2/11/2022	2/22/2022	11	0.000%	0.0000
4000461060	13911	71,553	2/14/2022	2/25/2022	11	0.019%	0.0021
4000461067	26363	643	2/14/2022	2/25/2022	11	0.000%	0.0000
4000461068	26381	1,920	2/14/2022	2/25/2022	11	0.001%	0.0001
4000461054	139275	195	2/14/2022	2/25/2022	11	0.000%	0.0000
4000461055	142870	22,970	2/14/2022	2/25/2022	11	0.006%	0.0007
4000461058	201066	1,328	2/14/2022	2/25/2022	11	0.000%	0.0000
4000461184	10384	7,600	2/17/2022	2/28/2022	11	0.002%	0.0002
4000461185	11054	6,747	2/17/2022	2/28/2022	11	0.002%	0.0002
4000461194	25809	3,014	2/17/2022	2/28/2022	11	0.001%	0.0001
4000461196	27013	16,471	2/17/2022	2/28/2022	11	0.004%	0.0005
4000461197	27994	880	2/17/2022	2/28/2022	11	0.000%	0.0000
4000461201	32537	3,080	2/17/2022	2/28/2022	11	0.001%	0.0001
4000461178	140752	2,802	2/17/2022	2/28/2022	11	0.001%	0.0001
4000461182	143941	4,374	2/17/2022	2/28/2022	11	0.001%	0.0001
4000461244	18267	3,908	2/18/2022	3/1/2022	11	0.001%	0.0001
4000461246	24281	19,696	2/18/2022	3/1/2022	11	0.005%	0.0006
4000461250	26659	4,114	2/18/2022	3/1/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461254	30475	112,337	2/18/2022	3/1/2022	11	0.030%	0.0033
4000461255	30475	123,698	2/18/2022	3/1/2022	11	0.033%	0.0036
4000461256	33238	1,838	2/18/2022	3/1/2022	11	0.000%	0.0001
4000461258	34064	383	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461259	34341	7,000	2/18/2022	3/1/2022	11	0.002%	0.0002
4000461261	34658	2,000	2/18/2022	3/1/2022	11	0.001%	0.0001
4000461262	34894	19,439	2/18/2022	3/1/2022	11	0.005%	0.0006
4000461263	105195	1,365	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461216	104872	1,135	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461217	105195	1,383	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461221	116384	695	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461222	118807	1,081	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461227	126628	1,789	2/18/2022	3/1/2022	11	0.000%	0.0001
4000461228	126721	1,513	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461230	132466	1,445	2/18/2022	3/1/2022	11	0.000%	0.0000
4000461238	144097	2,048,114	2/18/2022	3/1/2022	11	0.540%	0.0594
4000461239	144222	1,838	2/18/2022	3/1/2022	11	0.000%	0.0001
4000461392	11372	2,353	2/24/2022	3/7/2022	11	0.001%	0.0001
4000461403	105195	592	2/24/2022	3/7/2022	11	0.000%	0.0000
4000461377	125742	10,480	2/24/2022	3/7/2022	11	0.003%	0.0003
4000461441	9121	1,500	2/25/2022	3/8/2022	11	0.000%	0.0000
4000461442	17342	15,255	2/25/2022	3/8/2022	11	0.004%	0.0004
4000461448	25131	380	2/25/2022	3/8/2022	11	0.000%	0.0000
4000461456	28474	785	2/25/2022	3/8/2022	11	0.000%	0.0000
4000461464	117331	19,600	2/25/2022	3/8/2022	11	0.005%	0.0006
4000461418	103008	1,559	2/25/2022	3/8/2022	11	0.000%	0.0000
4000461419	108289	271	2/25/2022	3/8/2022	11	0.000%	0.0000
4000461420	112215	8,832	2/25/2022	3/8/2022	11	0.002%	0.0003
4000461423	132202	5,799	2/25/2022	3/8/2022	11	0.002%	0.0002
4000461509	27994	4,070	2/28/2022	3/11/2022	11	0.001%	0.0001
4000461473	100212	20,000	2/28/2022	3/11/2022	11	0.005%	0.0006
4000461476	104720	10,000	2/28/2022	3/11/2022	11	0.003%	0.0003
4000461491	142942	514	2/28/2022	3/11/2022	11	0.000%	0.0000
4000461625	24281	1,816	3/3/2022	3/14/2022	11	0.000%	0.0001
4000461628	29919	2,295	3/3/2022	3/14/2022	11	0.001%	0.0001
4000461630	34064	251,438	3/3/2022	3/14/2022	11	0.066%	0.0073
4000461631	117331	6,600	3/3/2022	3/14/2022	11	0.002%	0.0002
4000461610	116384	286	3/3/2022	3/14/2022	11	0.000%	0.0000
4000461616	143577	9,250	3/3/2022	3/14/2022	11	0.002%	0.0003
4000461619	144510	2,000	3/3/2022	3/14/2022	11	0.001%	0.0001
4000461657	18267	8,853	3/4/2022	3/15/2022	11	0.002%	0.0003
4000461670	34341	3,300	3/4/2022	3/15/2022	11	0.001%	0.0001
4000461673	117331	3,300	3/4/2022	3/15/2022	11	0.001%	0.0001
4000461633	4502	34,660	3/4/2022	3/15/2022	11	0.009%	0.0010
4000461636	105195	1,206	3/4/2022	3/15/2022	11	0.000%	0.0000
4000461638	116051	575	3/4/2022	3/15/2022	11	0.000%	0.0000
4000461639	116384	58	3/4/2022	3/15/2022	11	0.000%	0.0000
4000461640	117392	6,880	3/4/2022	3/15/2022	11	0.002%	0.0002
4000461641	125742	900	3/4/2022	3/15/2022	11	0.000%	0.0000
4000461642	129855	213,902	3/4/2022	3/15/2022	11	0.056%	0.0062
4000461643	135488	22,944	3/4/2022	3/15/2022	11	0.006%	0.0007
4000461644	139982	9,434	3/4/2022	3/15/2022	11	0.002%	0.0003
4000461645	142607	2,500	3/4/2022	3/15/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461647	143340	327,028	3/4/2022	3/15/2022	11	0.086%	0.0095
4000461648	143436	836	3/4/2022	3/15/2022	11	0.000%	0.0000
4000461655	144972	17,310	3/4/2022	3/15/2022	11	0.005%	0.0005
4000461680	103471	1,688	3/7/2022	3/18/2022	11	0.000%	0.0000
4000461696	141389	750	3/7/2022	3/18/2022	11	0.000%	0.0000
4000461698	142942	261	3/7/2022	3/18/2022	11	0.000%	0.0000
4000461785	11372	2,326	3/10/2022	3/21/2022	11	0.001%	0.0001
4000461792	26639	9,045	3/10/2022	3/21/2022	11	0.002%	0.0003
4000461799	28619	523	3/10/2022	3/21/2022	11	0.000%	0.0000
4000461766	15871	2,843	3/10/2022	3/21/2022	11	0.001%	0.0001
4000461770	121825	11,428	3/10/2022	3/21/2022	11	0.003%	0.0003
4000461771	125742	9,417	3/10/2022	3/21/2022	11	0.002%	0.0003
4000461777	143030	120,000	3/10/2022	3/21/2022	11	0.032%	0.0035
4000461780	143588	24,368	3/10/2022	3/21/2022	11	0.006%	0.0007
4000461839	11536	3,058	3/11/2022	3/22/2022	11	0.001%	0.0001
4000461846	33770	31,194	3/11/2022	3/22/2022	11	0.008%	0.0009
4000461849	34393	1,173	3/11/2022	3/22/2022	11	0.000%	0.0000
4000461808	4502	14,622	3/11/2022	3/22/2022	11	0.004%	0.0004
4000461814	30580	2,801	3/11/2022	3/22/2022	11	0.001%	0.0001
4000461818	103471	2,456	3/11/2022	3/22/2022	11	0.001%	0.0001
4000461823	121825	17,141	3/11/2022	3/22/2022	11	0.005%	0.0005
4000461824	125742	35,603	3/11/2022	3/22/2022	11	0.009%	0.0010
4000461855	107938	2,500	3/14/2022	3/25/2022	11	0.001%	0.0001
4000461865	142942	7,827	3/14/2022	3/25/2022	11	0.002%	0.0002
4000461992	27013	38,730	3/17/2022	3/28/2022	11	0.010%	0.0011
4000461994	30475	66,040	3/17/2022	3/28/2022	11	0.017%	0.0019
4000461995	30475	76,519	3/17/2022	3/28/2022	11	0.020%	0.0022
4000462000	105195	1,764	3/17/2022	3/28/2022	11	0.000%	0.0001
4000461963	24259	2,056	3/17/2022	3/28/2022	11	0.001%	0.0001
4000461971	121825	5,714	3/17/2022	3/28/2022	11	0.002%	0.0002
4000461973	125742	3,200	3/17/2022	3/28/2022	11	0.001%	0.0001
4000461976	138494	3,080	3/17/2022	3/28/2022	11	0.001%	0.0001
4000462043	26453	1,730	3/18/2022	3/29/2022	11	0.000%	0.0001
4000462048	27982	1,660	3/18/2022	3/29/2022	11	0.000%	0.0000
4000462005	4502	1,040	3/18/2022	3/29/2022	11	0.000%	0.0000
4000462006	4765	360	3/18/2022	3/29/2022	11	0.000%	0.0000
4000462017	119251	8,347	3/18/2022	3/29/2022	11	0.002%	0.0002
4000462018	125742	13,634	3/18/2022	3/29/2022	11	0.004%	0.0004
4000462021	138494	3,080	3/18/2022	3/29/2022	11	0.001%	0.0001
4000462023	141101	239,601	3/18/2022	3/29/2022	11	0.063%	0.0070
4000462030	144546	690	3/18/2022	3/29/2022	11	0.000%	0.0000
4000462085	9673	13,975	3/21/2022	4/1/2022	11	0.004%	0.0004
4000462099	26301	1,498	3/21/2022	4/1/2022	11	0.000%	0.0000
4000462101	26361	361	3/21/2022	4/1/2022	11	0.000%	0.0000
4000462105	26639	17,685	3/21/2022	4/1/2022	11	0.005%	0.0005
4000462107	26643	1,001	3/21/2022	4/1/2022	11	0.000%	0.0000
4000462070	126928	312	3/21/2022	4/1/2022	11	0.000%	0.0000
4000462071	131493	10,000	3/21/2022	4/1/2022	11	0.003%	0.0003
4000462072	132321	3,823	3/21/2022	4/1/2022	11	0.001%	0.0001
4000462188	25987	1,600	3/24/2022	4/4/2022	11	0.000%	0.0000
4000462170	104872	42	3/24/2022	4/4/2022	11	0.000%	0.0000
4000462175	125742	1,380	3/24/2022	4/4/2022	11	0.000%	0.0000
4000462228	18267	1,544	3/25/2022	4/5/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462199	4765	23,832	3/25/2022	4/5/2022	11	0.006%	0.0007
4000462207	105195	1,750	3/25/2022	4/5/2022	11	0.000%	0.0001
4000462211	133539	47,000	3/25/2022	4/5/2022	11	0.012%	0.0014
4000462213	139503	27,124	3/25/2022	4/5/2022	11	0.007%	0.0008
4000462215	141101	166,918	3/25/2022	4/5/2022	11	0.044%	0.0048
4000462223	144860	3,000	3/25/2022	4/5/2022	11	0.001%	0.0001
4000462259	13911	49,708	3/28/2022	4/8/2022	11	0.013%	0.0014
4000462269	26643	1,572	3/28/2022	4/8/2022	11	0.000%	0.0000
4000462272	28084	32,585	3/28/2022	4/8/2022	11	0.009%	0.0009
4000462241	9891	13,878	3/28/2022	4/8/2022	11	0.004%	0.0004
4000462439	25029	4,368	3/31/2022	4/11/2022	11	0.001%	0.0001
4000462452	27704	2,100	3/31/2022	4/11/2022	11	0.001%	0.0001
4000462457	32400	10,368	3/31/2022	4/11/2022	11	0.003%	0.0003
4000462466	134272	2,125	3/31/2022	4/11/2022	11	0.001%	0.0001
4000462408	15871	1,878	3/31/2022	4/11/2022	11	0.000%	0.0001
4000462425	143477	1,617	3/31/2022	4/11/2022	11	0.000%	0.0000
4000462429	144270	285	3/31/2022	4/11/2022	11	0.000%	0.0000
4000462525	24259	8,801	4/1/2022	4/12/2022	11	0.002%	0.0003
4000462530	25905	2,600	4/1/2022	4/12/2022	11	0.001%	0.0001
4000462540	32808	880	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462473	4502	9,401	4/1/2022	4/12/2022	11	0.002%	0.0003
4000462474	4765	9,817	4/1/2022	4/12/2022	11	0.003%	0.0003
4000462476	15871	4,448	4/1/2022	4/12/2022	11	0.001%	0.0001
4000462477	20287	425	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462480	103114	993	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462485	106674	43,891	4/1/2022	4/12/2022	11	0.012%	0.0013
4000462486	111669	60	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462498	139487	240	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462499	139503	3,024	4/1/2022	4/12/2022	11	0.001%	0.0001
4000462501	139982	9,434	4/1/2022	4/12/2022	11	0.002%	0.0003
4000462509	144085	122	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462513	144803	42,712	4/1/2022	4/12/2022	11	0.011%	0.0012
4000462468	107932	30	4/1/2022	4/12/2022	11	0.000%	0.0000
4000462516	116971	3,000	4/1/2022	4/12/2022	11	0.001%	0.0001
4000462517	116971	3,000	4/1/2022	4/12/2022	11	0.001%	0.0001
4000462588	20332	1,900	4/4/2022	4/15/2022	11	0.001%	0.0001
4000462550	30580	142	4/4/2022	4/15/2022	11	0.000%	0.0000
4000462553	126715	10,000	4/4/2022	4/15/2022	11	0.003%	0.0003
4000462565	142002	7,696	4/4/2022	4/15/2022	11	0.002%	0.0002
4000462577	143929	22,666	4/4/2022	4/15/2022	11	0.006%	0.0007
4000462646	4502	7,377	4/7/2022	4/18/2022	11	0.002%	0.0002
4000462661	142885	3,047	4/7/2022	4/18/2022	11	0.001%	0.0001
4000462666	144270	23,340	4/7/2022	4/18/2022	11	0.006%	0.0007
4000462733	28474	2,913	4/8/2022	4/19/2022	11	0.001%	0.0001
4000462736	30475	27,961	4/8/2022	4/19/2022	11	0.007%	0.0008
4000462737	30475	38,338	4/8/2022	4/19/2022	11	0.010%	0.0011
4000462740	34064	610	4/8/2022	4/19/2022	11	0.000%	0.0000
4000462689	4502	8,473	4/8/2022	4/19/2022	11	0.002%	0.0002
4000462690	4765	9,680	4/8/2022	4/19/2022	11	0.003%	0.0003
4000462695	104872	782	4/8/2022	4/19/2022	11	0.000%	0.0000
4000462700	118807	146	4/8/2022	4/19/2022	11	0.000%	0.0000
4000462707	139503	27,124	4/8/2022	4/19/2022	11	0.007%	0.0008
4000462711	143477	3,675	4/8/2022	4/19/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462720	144620	187,501	4/8/2022	4/19/2022	11	0.049%	0.0054
4000462724	116971	3,000	4/8/2022	4/19/2022	11	0.001%	0.0001
4000462763	11536	3,438	4/11/2022	4/22/2022	11	0.001%	0.0001
4000462769	25808	1,140	4/11/2022	4/22/2022	11	0.000%	0.0000
4000462749	104872	1,612	4/11/2022	4/22/2022	11	0.000%	0.0000
4000462906	25809	858	4/14/2022	4/25/2022	11	0.000%	0.0000
4000462908	26356	2,634	4/14/2022	4/25/2022	11	0.001%	0.0001
4000462911	28530	18,581	4/14/2022	4/25/2022	11	0.005%	0.0005
4000462914	30475	51,642	4/14/2022	4/25/2022	11	0.014%	0.0015
4000462915	30475	58,694	4/14/2022	4/25/2022	11	0.015%	0.0017
4000462917	30475	94,614	4/14/2022	4/25/2022	11	0.025%	0.0027
4000462918	30475	43,761	4/14/2022	4/25/2022	11	0.012%	0.0013
4000462919	30475	45,697	4/14/2022	4/25/2022	11	0.012%	0.0013
4000462920	30475	49,238	4/14/2022	4/25/2022	11	0.013%	0.0014
4000462922	33770	105,636	4/14/2022	4/25/2022	11	0.028%	0.0031
4000462868	27094	10,293	4/14/2022	4/25/2022	11	0.003%	0.0003
4000462877	142926	104,748	4/14/2022	4/25/2022	11	0.028%	0.0030
4000462878	142942	25,650	4/14/2022	4/25/2022	11	0.007%	0.0007
4000462886	144084	1,205	4/14/2022	4/25/2022	11	0.000%	0.0000
4000462934	102473	650	4/18/2022	4/29/2022	11	0.000%	0.0000
4000463066	26655	1,488	4/21/2022	5/2/2022	11	0.000%	0.0000
4000463068	26674	1,960	4/21/2022	5/2/2022	11	0.001%	0.0001
4000463074	126165	1,722	4/21/2022	5/2/2022	11	0.000%	0.0000
4000463040	142926	26,700	4/21/2022	5/2/2022	11	0.007%	0.0008
4000463041	142942	3,852	4/21/2022	5/2/2022	11	0.001%	0.0001
4000463117	18267	4,829	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463120	27013	28,292	4/22/2022	5/3/2022	11	0.007%	0.0008
4000463126	30257	2,735	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463136	34658	2,000	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463137	105195	3,320	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463139	117331	26,150	4/22/2022	5/3/2022	11	0.007%	0.0008
4000463076	4502	6,057	4/22/2022	5/3/2022	11	0.002%	0.0002
4000463077	4765	22,227	4/22/2022	5/3/2022	11	0.006%	0.0006
4000463084	101853	748	4/22/2022	5/3/2022	11	0.000%	0.0000
4000463086	102637	171	4/22/2022	5/3/2022	11	0.000%	0.0000
4000463088	105195	18,390	4/22/2022	5/3/2022	11	0.005%	0.0005
4000463089	116384	135	4/22/2022	5/3/2022	11	0.000%	0.0000
4000463090	118807	42	4/22/2022	5/3/2022	11	0.000%	0.0000
4000463094	133414	7,150	4/22/2022	5/3/2022	11	0.002%	0.0002
4000463095	137204	4,934	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463099	141858	2,560	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463102	143340	436,038	4/22/2022	5/3/2022	11	0.115%	0.0127
4000463109	144567	1,516	4/22/2022	5/3/2022	11	0.000%	0.0000
4000463112	144955	4,002	4/22/2022	5/3/2022	11	0.001%	0.0001
4000463291	11536	2,660	4/28/2022	5/9/2022	11	0.001%	0.0001
4000463298	24211	2,449	4/28/2022	5/9/2022	11	0.001%	0.0001
4000463312	26643	2,000	4/28/2022	5/9/2022	11	0.001%	0.0001
4000463316	28084	9,310	4/28/2022	5/9/2022	11	0.002%	0.0003
4000463262	6031	2,680	4/28/2022	5/9/2022	11	0.001%	0.0001
4000463275	125960	195	4/28/2022	5/9/2022	11	0.000%	0.0000
4000463368	13534	24,497	4/29/2022	5/10/2022	11	0.006%	0.0007
4000463369	18267	823	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463371	24113	5,696	4/29/2022	5/10/2022	11	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463376	24825	3,480	4/29/2022	5/10/2022	11	0.001%	0.0001
4000463379	26363	829	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463385	28474	3,480	4/29/2022	5/10/2022	11	0.001%	0.0001
4000463386	28530	20,327	4/29/2022	5/10/2022	11	0.005%	0.0006
4000463395	33956	3,412	4/29/2022	5/10/2022	11	0.001%	0.0001
4000463396	34064	252,122	4/29/2022	5/10/2022	11	0.066%	0.0073
4000463397	34341	2,653	4/29/2022	5/10/2022	11	0.001%	0.0001
4000463399	34937	12,000	4/29/2022	5/10/2022	11	0.003%	0.0003
4000463400	117331	475	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463325	4502	1,346	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463330	103392	390	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463331	105195	27,817	4/29/2022	5/10/2022	11	0.007%	0.0008
4000463332	108289	65	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463337	116384	53	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463344	139487	260	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463345	139503	94,736	4/29/2022	5/10/2022	11	0.025%	0.0027
4000463346	139713	162,925	4/29/2022	5/10/2022	11	0.043%	0.0047
4000463352	143463	27,290	4/29/2022	5/10/2022	11	0.007%	0.0008
4000463357	143892	1,550	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463359	144567	130	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463360	144741	1,592	4/29/2022	5/10/2022	11	0.000%	0.0000
4000463362	144955	2,526	4/29/2022	5/10/2022	11	0.001%	0.0001
4000463423	8392	43,900	5/2/2022	5/13/2022	11	0.012%	0.0013
4000463419	132507	18,615	5/2/2022	5/13/2022	11	0.005%	0.0005
4000463549	34888	491	5/5/2022	5/16/2022	11	0.000%	0.0000
4000463552	103392	27	5/5/2022	5/16/2022	11	0.000%	0.0000
4000463560	134862	216,814	5/5/2022	5/16/2022	11	0.057%	0.0063
4000463566	144270	38,900	5/5/2022	5/16/2022	11	0.010%	0.0011
4000463621	33770	5,341	5/6/2022	5/17/2022	11	0.001%	0.0002
4000463624	117331	21,150	5/6/2022	5/17/2022	11	0.006%	0.0006
4000463577	4765	304,940	5/6/2022	5/17/2022	11	0.080%	0.0088
4000463584	103008	847	5/6/2022	5/17/2022	11	0.000%	0.0000
4000463594	139503	3,888	5/6/2022	5/17/2022	11	0.001%	0.0001
4000463597	143340	69,174	5/6/2022	5/17/2022	11	0.018%	0.0020
4000463601	144270	31,120	5/6/2022	5/17/2022	11	0.008%	0.0009
4000463607	144955	2,693	5/6/2022	5/17/2022	11	0.001%	0.0001
4000463642	27962	3,533	5/9/2022	5/20/2022	11	0.001%	0.0001
4000463634	144270	13,280	5/9/2022	5/20/2022	11	0.004%	0.0004
4000463749	11372	2,446	5/12/2022	5/23/2022	11	0.001%	0.0001
4000463742	112215	12,768	5/12/2022	5/23/2022	11	0.003%	0.0004
4000463735	125009	5,821	5/12/2022	5/23/2022	11	0.002%	0.0002
4000463792	24281	4,742	5/13/2022	5/24/2022	11	0.001%	0.0001
4000463793	24765	3,405	5/13/2022	5/24/2022	11	0.001%	0.0001
4000463794	24825	7,337	5/13/2022	5/24/2022	11	0.002%	0.0002
4000463796	25437	3,750	5/13/2022	5/24/2022	11	0.001%	0.0001
4000463797	25599	970	5/13/2022	5/24/2022	11	0.000%	0.0000
4000463805	28530	22,072	5/13/2022	5/24/2022	11	0.006%	0.0006
4000463816	33770	21,126	5/13/2022	5/24/2022	11	0.006%	0.0006
4000463817	33956	3,180	5/13/2022	5/24/2022	11	0.001%	0.0001
4000463822	117331	46,043	5/13/2022	5/24/2022	11	0.012%	0.0013
4000463756	4502	29,314	5/13/2022	5/24/2022	11	0.008%	0.0009
4000463757	10384	3,800	5/13/2022	5/24/2022	11	0.001%	0.0001
4000463766	105195	1,506	5/13/2022	5/24/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463771	121825	42,746	5/13/2022	5/24/2022	11	0.011%	0.0012
4000463773	125742	20,843	5/13/2022	5/24/2022	11	0.005%	0.0006
4000463777	138494	5,520	5/13/2022	5/24/2022	11	0.001%	0.0002
4000463781	142942	22,998	5/13/2022	5/24/2022	11	0.006%	0.0007
4000463784	144270	900	5/13/2022	5/24/2022	11	0.000%	0.0000
4000463788	144955	10,682	5/13/2022	5/24/2022	11	0.003%	0.0003
4000463881	13911	1,100	5/16/2022	5/27/2022	11	0.000%	0.0000
4000463897	27068	8,294	5/16/2022	5/27/2022	11	0.002%	0.0002
4000463899	32897	900	5/16/2022	5/27/2022	11	0.000%	0.0000
4000463828	26604	8,030	5/16/2022	5/27/2022	11	0.002%	0.0002
4000463834	109140	5,000	5/16/2022	5/27/2022	11	0.001%	0.0001
4000463840	117787	1,000	5/16/2022	5/27/2022	11	0.000%	0.0000
4000463842	122098	25,000	5/16/2022	5/27/2022	11	0.007%	0.0007
4000463844	122421	1,500	5/16/2022	5/27/2022	11	0.000%	0.0000
4000463845	122480	4,750	5/16/2022	5/27/2022	11	0.001%	0.0001
4000463862	135469	1,500	5/16/2022	5/27/2022	11	0.000%	0.0000
4000463869	143477	200	5/16/2022	5/27/2022	11	0.000%	0.0000
4000464051	29919	2,355	5/20/2022	5/31/2022	11	0.001%	0.0001
4000464052	30257	121,246	5/20/2022	5/31/2022	11	0.032%	0.0035
4000464059	34064	125	5/20/2022	5/31/2022	11	0.000%	0.0000
4000464061	34658	2,000	5/20/2022	5/31/2022	11	0.001%	0.0001
4000464015	7214	216,563	5/20/2022	5/31/2022	11	0.057%	0.0063
4000464021	104261	80	5/20/2022	5/31/2022	11	0.000%	0.0000
4000464024	116384	78	5/20/2022	5/31/2022	11	0.000%	0.0000
4000464025	118807	598	5/20/2022	5/31/2022	11	0.000%	0.0000
4000464026	121825	110,990	5/20/2022	5/31/2022	11	0.029%	0.0032
4000464027	125742	8,303	5/20/2022	5/31/2022	11	0.002%	0.0002
4000464029	137204	14,361	5/20/2022	5/31/2022	11	0.004%	0.0004
4000464031	142613	11,954	5/20/2022	5/31/2022	11	0.003%	0.0003
4000464032	142635	13,818	5/20/2022	5/31/2022	11	0.004%	0.0004
4000464036	143584	35,210	5/20/2022	5/31/2022	11	0.009%	0.0010
4000464037	143920	2	5/20/2022	5/31/2022	11	0.000%	0.0000
4000464039	144270	47,718	5/20/2022	5/31/2022	11	0.013%	0.0014
4000464041	144860	3,000	5/20/2022	5/31/2022	11	0.001%	0.0001
4000464042	144955	11,099	5/20/2022	5/31/2022	11	0.003%	0.0003
4000464084	144581	4,349	5/23/2022	6/3/2022	11	0.001%	0.0001
4000464208	8392	13,214	5/26/2022	6/6/2022	11	0.003%	0.0004
4000464216	26362	2,750	5/26/2022	6/6/2022	11	0.001%	0.0001
4000464222	27994	2,200	5/26/2022	6/6/2022	11	0.001%	0.0001
4000464224	28530	22,329	5/26/2022	6/6/2022	11	0.006%	0.0006
4000464184	101853	5,431	5/26/2022	6/6/2022	11	0.001%	0.0002
4000464195	142613	9,743	5/26/2022	6/6/2022	11	0.003%	0.0003
4000464196	142926	7,852	5/26/2022	6/6/2022	11	0.002%	0.0002
4000464198	143577	9,981	5/26/2022	6/6/2022	11	0.003%	0.0003
4000464206	145099	114,500	5/26/2022	6/6/2022	11	0.030%	0.0033
4000464294	27305	4,000	5/27/2022	6/7/2022	11	0.001%	0.0001
4000464301	33956	5,383	5/27/2022	6/7/2022	11	0.001%	0.0002
4000464302	34658	4,500	5/27/2022	6/7/2022	11	0.001%	0.0001
4000464303	34937	12,000	5/27/2022	6/7/2022	11	0.003%	0.0003
4000464305	109948	201	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464306	117331	70,173	5/27/2022	6/7/2022	11	0.019%	0.0020
4000464307	117331	75,872	5/27/2022	6/7/2022	11	0.020%	0.0022
4000464308	117331	67,391	5/27/2022	6/7/2022	11	0.018%	0.0020

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464243	17667	122,900	5/27/2022	6/7/2022	11	0.032%	0.0036
4000464248	27094	20,022	5/27/2022	6/7/2022	11	0.005%	0.0006
4000464253	104509	4,113	5/27/2022	6/7/2022	11	0.001%	0.0001
4000464255	105195	8,939	5/27/2022	6/7/2022	11	0.002%	0.0003
4000464256	112103	67,373	5/27/2022	6/7/2022	11	0.018%	0.0020
4000464258	116384	319	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464260	118807	1,660	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464261	119251	9,470	5/27/2022	6/7/2022	11	0.002%	0.0003
4000464263	123377	9,091	5/27/2022	6/7/2022	11	0.002%	0.0003
4000464268	132094	8,147	5/27/2022	6/7/2022	11	0.002%	0.0002
4000464269	133414	15,122	5/27/2022	6/7/2022	11	0.004%	0.0004
4000464270	135488	35,850	5/27/2022	6/7/2022	11	0.009%	0.0010
4000464272	141256	35	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464277	143312	37,662	5/27/2022	6/7/2022	11	0.010%	0.0011
4000464278	143340	1,495	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464279	143637	3,750	5/27/2022	6/7/2022	11	0.001%	0.0001
4000464280	143659	19,317	5/27/2022	6/7/2022	11	0.005%	0.0006
4000464281	143659	6,800	5/27/2022	6/7/2022	11	0.002%	0.0002
4000464284	144530	7,884	5/27/2022	6/7/2022	11	0.002%	0.0002
4000464285	144687	704	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464286	144955	7,400	5/27/2022	6/7/2022	11	0.002%	0.0002
4000464288	145093	1,573	5/27/2022	6/7/2022	11	0.000%	0.0000
4000464475	26604	11,885	6/2/2022	6/13/2022	11	0.003%	0.0003
4000464476	26639	9,990	6/2/2022	6/13/2022	11	0.003%	0.0003
4000464479	30475	16,328	6/2/2022	6/13/2022	11	0.004%	0.0005
4000464482	34341	7,100	6/2/2022	6/13/2022	11	0.002%	0.0002
4000464486	129435	52,230	6/2/2022	6/13/2022	11	0.014%	0.0015
4000464415	6031	2,113	6/2/2022	6/13/2022	11	0.001%	0.0001
4000464417	15871	1,157	6/2/2022	6/13/2022	11	0.000%	0.0000
4000464418	26958	5,419	6/2/2022	6/13/2022	11	0.001%	0.0002
4000464421	103392	1,370	6/2/2022	6/13/2022	11	0.000%	0.0000
4000464423	111669	249	6/2/2022	6/13/2022	11	0.000%	0.0000
4000464428	121825	71,993	6/2/2022	6/13/2022	11	0.019%	0.0021
4000464429	125742	3,200	6/2/2022	6/13/2022	11	0.001%	0.0001
4000464433	136045	42,000	6/2/2022	6/13/2022	11	0.011%	0.0012
4000464438	141025	18,000	6/2/2022	6/13/2022	11	0.005%	0.0005
4000464444	142162	11,000	6/2/2022	6/13/2022	11	0.003%	0.0003
4000464451	143364	12,300	6/2/2022	6/13/2022	11	0.003%	0.0004
4000464453	143477	800	6/2/2022	6/13/2022	11	0.000%	0.0000
4000464455	143807	1,058	6/2/2022	6/13/2022	11	0.000%	0.0000
4000464459	144410	2,850	6/2/2022	6/13/2022	11	0.001%	0.0001
4000464461	144530	17,847	6/2/2022	6/13/2022	11	0.005%	0.0005
4000464530	26604	655	6/3/2022	6/14/2022	11	0.000%	0.0000
4000464531	26659	27,490	6/3/2022	6/14/2022	11	0.007%	0.0008
4000464537	33956	450	6/3/2022	6/14/2022	11	0.000%	0.0000
4000464539	34341	22,000	6/3/2022	6/14/2022	11	0.006%	0.0006
4000464490	4502	16,416	6/3/2022	6/14/2022	11	0.004%	0.0005
4000464496	103392	46	6/3/2022	6/14/2022	11	0.000%	0.0000
4000464507	141409	750	6/3/2022	6/14/2022	11	0.000%	0.0000
4000464520	144816	6,900	6/3/2022	6/14/2022	11	0.002%	0.0002
4000464523	144986	4,000	6/3/2022	6/14/2022	11	0.001%	0.0001
4000464524	144996	2,500	6/3/2022	6/14/2022	11	0.001%	0.0001
4000464562	25809	319	6/6/2022	6/17/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464566	26644	6,210	6/6/2022	6/17/2022	11	0.002%	0.0002
4000464720	18275	17,680	6/10/2022	6/21/2022	11	0.005%	0.0005
4000464721	18518	3,950	6/10/2022	6/21/2022	11	0.001%	0.0001
4000464727	27013	3,601	6/10/2022	6/21/2022	11	0.001%	0.0001
4000464733	33956	5,981	6/10/2022	6/21/2022	11	0.002%	0.0002
4000464734	34064	209	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464735	34341	7,000	6/10/2022	6/21/2022	11	0.002%	0.0002
4000464740	126775	10,963	6/10/2022	6/21/2022	11	0.003%	0.0003
4000464741	133795	11,499	6/10/2022	6/21/2022	11	0.003%	0.0003
4000464687	27094	1,766	6/10/2022	6/21/2022	11	0.000%	0.0001
4000464689	32842	121	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464690	34888	20	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464695	111770	249	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464696	116384	632	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464697	118807	12,978	6/10/2022	6/21/2022	11	0.003%	0.0004
4000464698	121825	29,997	6/10/2022	6/21/2022	11	0.008%	0.0009
4000464699	125742	4,200	6/10/2022	6/21/2022	11	0.001%	0.0001
4000464702	134862	141,990	6/10/2022	6/21/2022	11	0.037%	0.0041
4000464703	135488	272	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464705	142635	12,723	6/10/2022	6/21/2022	11	0.003%	0.0004
4000464707	143072	302	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464708	143477	15,386	6/10/2022	6/21/2022	11	0.004%	0.0004
4000464709	143659	73,859	6/10/2022	6/21/2022	11	0.019%	0.0021
4000464711	143920	213	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464712	144270	50,337	6/10/2022	6/21/2022	11	0.013%	0.0015
4000464713	144663	169,696	6/10/2022	6/21/2022	11	0.045%	0.0049
4000464714	144949	135	6/10/2022	6/21/2022	11	0.000%	0.0000
4000464758	24113	6,149	6/13/2022	6/24/2022	11	0.002%	0.0002
4000464762	24383	6,046	6/13/2022	6/24/2022	11	0.002%	0.0002
4000464763	24765	2,829	6/13/2022	6/24/2022	11	0.001%	0.0001
4000464765	25131	1,045	6/13/2022	6/24/2022	11	0.000%	0.0000
4000464767	25599	970	6/13/2022	6/24/2022	11	0.000%	0.0000
4000464776	26642	4,773	6/13/2022	6/24/2022	11	0.001%	0.0001
4000464780	27994	2,200	6/13/2022	6/24/2022	11	0.001%	0.0001
4000464742	25147	257,034	6/13/2022	6/24/2022	11	0.068%	0.0075
4000464744	105195	20,656	6/13/2022	6/24/2022	11	0.005%	0.0006
4000464749	144567	12,085	6/13/2022	6/24/2022	11	0.003%	0.0004
4000464752	145181	1,200	6/13/2022	6/24/2022	11	0.000%	0.0000
4000464866	4502	16,505	6/16/2022	6/27/2022	11	0.004%	0.0005
4000464868	101853	25,658	6/16/2022	6/27/2022	11	0.007%	0.0007
4000464869	111108	9,945	6/16/2022	6/27/2022	11	0.003%	0.0003
4000464873	137512	50,000	6/16/2022	6/27/2022	11	0.013%	0.0015
4000464875	139128	3,560	6/16/2022	6/27/2022	11	0.001%	0.0001
4000464878	142942	910	6/16/2022	6/27/2022	11	0.000%	0.0000
4000464879	143072	2,358	6/16/2022	6/27/2022	11	0.001%	0.0001
4000464886	144955	53	6/16/2022	6/27/2022	11	0.000%	0.0000
4000464942	18267	4,588	6/17/2022	6/28/2022	11	0.001%	0.0001
4000464943	24383	5,288	6/17/2022	6/28/2022	11	0.001%	0.0002
4000464967	34064	1,500	6/17/2022	6/28/2022	11	0.000%	0.0000
4000464970	105195	4,132	6/17/2022	6/28/2022	11	0.001%	0.0001
4000464971	117331	15,900	6/17/2022	6/28/2022	11	0.004%	0.0005
4000464972	124943	760	6/17/2022	6/28/2022	11	0.000%	0.0000
4000464976	126775	4,907	6/17/2022	6/28/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464906	105195	8,896	6/17/2022	6/28/2022	11	0.002%	0.0003
4000464909	116384	241	6/17/2022	6/28/2022	11	0.000%	0.0000
4000464911	118807	27,488	6/17/2022	6/28/2022	11	0.007%	0.0008
4000464914	126775	2,352	6/17/2022	6/28/2022	11	0.001%	0.0001
4000464916	134480	2,026	6/17/2022	6/28/2022	11	0.001%	0.0001
4000464917	134862	5,361	6/17/2022	6/28/2022	11	0.001%	0.0002
4000464923	142942	27,540	6/17/2022	6/28/2022	11	0.007%	0.0008
4000464926	143659	874	6/17/2022	6/28/2022	11	0.000%	0.0000
4000464928	144567	13,772	6/17/2022	6/28/2022	11	0.004%	0.0004
4000464929	144567	14,376	6/17/2022	6/28/2022	11	0.004%	0.0004
4000464930	144567	14,835	6/17/2022	6/28/2022	11	0.004%	0.0004
4000464931	144949	52	6/17/2022	6/28/2022	11	0.000%	0.0000
4000464994	26604	2,575	6/20/2022	7/1/2022	11	0.001%	0.0001
4000464980	104872	175	6/20/2022	7/1/2022	11	0.000%	0.0000
4000464984	122955	1,000	6/20/2022	7/1/2022	11	0.000%	0.0000
4000465150	17342	6,345	6/24/2022	7/5/2022	11	0.002%	0.0002
4000465151	18267	4,656	6/24/2022	7/5/2022	11	0.001%	0.0001
4000465164	30257	10,365	6/24/2022	7/5/2022	11	0.003%	0.0003
4000465168	33956	21,949	6/24/2022	7/5/2022	11	0.006%	0.0006
4000465171	34658	6,000	6/24/2022	7/5/2022	11	0.002%	0.0002
4000465173	134272	9,807	6/24/2022	7/5/2022	11	0.003%	0.0003
4000465114	15871	13,930	6/24/2022	7/5/2022	11	0.004%	0.0004
4000465115	21678	1,500	6/24/2022	7/5/2022	11	0.000%	0.0000
4000465116	27094	14,311	6/24/2022	7/5/2022	11	0.004%	0.0004
4000465117	34888	32	6/24/2022	7/5/2022	11	0.000%	0.0000
4000465119	105195	8,629	6/24/2022	7/5/2022	11	0.002%	0.0003
4000465122	113448	2,521	6/24/2022	7/5/2022	11	0.001%	0.0001
4000465124	121825	71,993	6/24/2022	7/5/2022	11	0.019%	0.0021
4000465126	125742	10,251	6/24/2022	7/5/2022	11	0.003%	0.0003
4000465127	134862	303,315	6/24/2022	7/5/2022	11	0.080%	0.0088
4000465128	139713	77,190	6/24/2022	7/5/2022	11	0.020%	0.0022
4000465129	142700	39,393	6/24/2022	7/5/2022	11	0.010%	0.0011
4000465132	143011	7,345	6/24/2022	7/5/2022	11	0.002%	0.0002
4000465133	143072	884	6/24/2022	7/5/2022	11	0.000%	0.0000
4000465138	144270	204,252	6/24/2022	7/5/2022	11	0.054%	0.0059
4000465140	144822	4,000	6/24/2022	7/5/2022	11	0.001%	0.0001
4000465141	144955	911	6/24/2022	7/5/2022	11	0.000%	0.0000
4000465200	8392	54,965	6/27/2022	7/8/2022	11	0.014%	0.0016
4000465203	11536	59,980	6/27/2022	7/8/2022	11	0.016%	0.0017
4000465212	24383	2,303	6/27/2022	7/8/2022	11	0.001%	0.0001
4000465215	25131	2,708	6/27/2022	7/8/2022	11	0.001%	0.0001
4000465223	26655	2,018	6/27/2022	7/8/2022	11	0.001%	0.0001
4000465225	27068	29,184	6/27/2022	7/8/2022	11	0.008%	0.0008
4000465226	27994	6,380	6/27/2022	7/8/2022	11	0.002%	0.0002
4000465227	28348	920	6/27/2022	7/8/2022	11	0.000%	0.0000
4000465191	132691	500	6/27/2022	7/8/2022	11	0.000%	0.0000
4000465369	27636	14,450	6/30/2022	7/11/2022	11	0.004%	0.0004
4000465377	126775	16,294	6/30/2022	7/11/2022	11	0.004%	0.0005
4000465298	13911	14,085	6/30/2022	7/11/2022	11	0.004%	0.0004
4000465304	104480	2,811	6/30/2022	7/11/2022	11	0.001%	0.0001
4000465311	131647	2,338	6/30/2022	7/11/2022	11	0.001%	0.0001
4000465319	141021	2,700	6/30/2022	7/11/2022	11	0.001%	0.0001
4000465336	143400	3,000	6/30/2022	7/11/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465344	144344	9,000	6/30/2022	7/11/2022	11	0.002%	0.0003
4000465354	144996	2,500	6/30/2022	7/11/2022	11	0.001%	0.0001
4000465429	13534	6,786	7/1/2022	7/12/2022	11	0.002%	0.0002
4000465453	28474	1,840	7/1/2022	7/12/2022	11	0.000%	0.0001
4000465461	33956	1,970	7/1/2022	7/12/2022	11	0.001%	0.0001
4000465462	34064	412	7/1/2022	7/12/2022	11	0.000%	0.0000
4000465466	117331	40,670	7/1/2022	7/12/2022	11	0.011%	0.0012
4000465379	4502	144,428	7/1/2022	7/12/2022	11	0.038%	0.0042
4000465380	9145	78,435	7/1/2022	7/12/2022	11	0.021%	0.0023
4000465384	24825	4,805	7/1/2022	7/12/2022	11	0.001%	0.0001
4000465388	27094	5,297	7/1/2022	7/12/2022	11	0.001%	0.0002
4000465403	116384	20	7/1/2022	7/12/2022	11	0.000%	0.0000
4000465408	135488	12,000	7/1/2022	7/12/2022	11	0.003%	0.0003
4000465410	139982	9,422	7/1/2022	7/12/2022	11	0.002%	0.0003
4000465415	143340	2,740	7/1/2022	7/12/2022	11	0.001%	0.0001
4000465421	144358	64,882	7/1/2022	7/12/2022	11	0.017%	0.0019
4000465531	6031	1,808	7/7/2022	7/18/2022	11	0.000%	0.0001
4000465535	101853	3,304	7/7/2022	7/18/2022	11	0.001%	0.0001
4000465542	138494	11,900	7/7/2022	7/18/2022	11	0.003%	0.0003
4000465596	11305	17,338	7/8/2022	7/19/2022	11	0.005%	0.0005
4000465599	14949	698	7/8/2022	7/19/2022	11	0.000%	0.0000
4000465601	24259	2,663	7/8/2022	7/19/2022	11	0.001%	0.0001
4000465603	24385	15,653	7/8/2022	7/19/2022	11	0.004%	0.0005
4000465615	26674	7,630	7/8/2022	7/19/2022	11	0.002%	0.0002
4000465619	29469	1,265	7/8/2022	7/19/2022	11	0.000%	0.0000
4000465620	30475	39,684	7/8/2022	7/19/2022	11	0.010%	0.0012
4000465624	34341	1,454	7/8/2022	7/19/2022	11	0.000%	0.0000
4000465628	117331	27,500	7/8/2022	7/19/2022	11	0.007%	0.0008
4000465564	4502	6,505	7/8/2022	7/19/2022	11	0.002%	0.0002
4000465566	15871	4,150	7/8/2022	7/19/2022	11	0.001%	0.0001
4000465572	108934	1,000	7/8/2022	7/19/2022	11	0.000%	0.0000
4000465579	142311	420	7/8/2022	7/19/2022	11	0.000%	0.0000
4000465584	143340	2,415	7/8/2022	7/19/2022	11	0.001%	0.0001
4000465647	8392	12,061	7/11/2022	7/22/2022	11	0.003%	0.0003
4000465652	25809	848	7/11/2022	7/22/2022	11	0.000%	0.0000
4000465634	104872	182	7/11/2022	7/22/2022	11	0.000%	0.0000
4000465793	11372	1,664	7/14/2022	7/25/2022	11	0.000%	0.0000
4000465781	124628	4,364	7/14/2022	7/25/2022	11	0.001%	0.0001
4000465786	142926	178,754	7/14/2022	7/25/2022	11	0.047%	0.0052
4000465842	11260	3,872	7/15/2022	7/26/2022	11	0.001%	0.0001
4000465847	25659	31,355	7/15/2022	7/26/2022	11	0.008%	0.0009
4000465814	4502	2,817	7/15/2022	7/26/2022	11	0.001%	0.0001
4000465821	134862	34,570	7/15/2022	7/26/2022	11	0.009%	0.0010
4000465832	143340	4,127	7/15/2022	7/26/2022	11	0.001%	0.0001
4000465813	125852	2,537	7/15/2022	7/26/2022	11	0.001%	0.0001
4000465887	27068	14,763	7/18/2022	7/29/2022	11	0.004%	0.0004
4000465866	24114	1,210	7/18/2022	7/29/2022	11	0.000%	0.0000
4000465870	108082	2,500	7/18/2022	7/29/2022	11	0.001%	0.0001
4000466006	24211	8,661	7/21/2022	8/1/2022	11	0.002%	0.0003
4000466008	24259	8,351	7/21/2022	8/1/2022	11	0.002%	0.0002
4000466011	26604	17,230	7/21/2022	8/1/2022	11	0.005%	0.0005
4000466013	28530	4,825	7/21/2022	8/1/2022	11	0.001%	0.0001
4000466014	30475	63,810	7/21/2022	8/1/2022	11	0.017%	0.0019

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466015	30475	70,102	7/21/2022	8/1/2022	11	0.018%	0.0020
4000466016	30475	54,851	7/21/2022	8/1/2022	11	0.014%	0.0016
4000466017	30475	57,183	7/21/2022	8/1/2022	11	0.015%	0.0017
4000465986	4909	296	7/21/2022	8/1/2022	11	0.000%	0.0000
4000466001	144530	6,850	7/21/2022	8/1/2022	11	0.002%	0.0002
4000466059	18267	18,920	7/22/2022	8/2/2022	11	0.005%	0.0005
4000466064	25708	2,387	7/22/2022	8/2/2022	11	0.001%	0.0001
4000466070	26659	26,430	7/22/2022	8/2/2022	11	0.007%	0.0008
4000466071	26674	1,540	7/22/2022	8/2/2022	11	0.000%	0.0000
4000466073	30257	77,591	7/22/2022	8/2/2022	11	0.020%	0.0023
4000466078	33956	2,690	7/22/2022	8/2/2022	11	0.001%	0.0001
4000466079	34064	239	7/22/2022	8/2/2022	11	0.000%	0.0000
4000466080	34341	1,325	7/22/2022	8/2/2022	11	0.000%	0.0000
4000466082	117331	23,000	7/22/2022	8/2/2022	11	0.006%	0.0007
4000466083	124943	2,993	7/22/2022	8/2/2022	11	0.001%	0.0001
4000466021	4502	17,976	7/22/2022	8/2/2022	11	0.005%	0.0005
4000466022	4765	9,500	7/22/2022	8/2/2022	11	0.003%	0.0003
4000466025	32842	1,885	7/22/2022	8/2/2022	11	0.000%	0.0001
4000466027	105195	28,974	7/22/2022	8/2/2022	11	0.008%	0.0008
4000466035	135488	60,228	7/22/2022	8/2/2022	11	0.016%	0.0017
4000466044	143426	72,085	7/22/2022	8/2/2022	11	0.019%	0.0021
4000466047	144567	2,200	7/22/2022	8/2/2022	11	0.001%	0.0001
4000466048	144567	3,738	7/22/2022	8/2/2022	11	0.001%	0.0001
4000466100	25379	1,310	7/25/2022	8/5/2022	11	0.000%	0.0000
4000466105	33747	1,368	7/25/2022	8/5/2022	11	0.000%	0.0000
4000466228	13911	560	7/28/2022	8/8/2022	11	0.000%	0.0000
4000466231	24259	1,542	7/28/2022	8/8/2022	11	0.000%	0.0000
4000466237	26674	560	7/28/2022	8/8/2022	11	0.000%	0.0000
4000466239	27013	18,354	7/28/2022	8/8/2022	11	0.005%	0.0005
4000466241	27704	2,800	7/28/2022	8/8/2022	11	0.001%	0.0001
4000466245	32896	1,900	7/28/2022	8/8/2022	11	0.001%	0.0001
4000466207	6031	1,901	7/28/2022	8/8/2022	11	0.001%	0.0001
4000466209	13911	4,920	7/28/2022	8/8/2022	11	0.001%	0.0001
4000466293	18267	9,687	7/29/2022	8/9/2022	11	0.003%	0.0003
4000466316	28474	5,586	7/29/2022	8/9/2022	11	0.001%	0.0002
4000466330	33956	12,625	7/29/2022	8/9/2022	11	0.003%	0.0004
4000466331	34064	243,660	7/29/2022	8/9/2022	11	0.064%	0.0071
4000466333	34341	24,425	7/29/2022	8/9/2022	11	0.006%	0.0007
4000466338	109948	14,612	7/29/2022	8/9/2022	11	0.004%	0.0004
4000466339	124943	1,045	7/29/2022	8/9/2022	11	0.000%	0.0000
4000466253	4502	13,210	7/29/2022	8/9/2022	11	0.003%	0.0004
4000466262	26958	4,476	7/29/2022	8/9/2022	11	0.001%	0.0001
4000466265	32842	3,020	7/29/2022	8/9/2022	11	0.001%	0.0001
4000466269	105195	7,013	7/29/2022	8/9/2022	11	0.002%	0.0002
4000466281	143312	43,818	7/29/2022	8/9/2022	11	0.012%	0.0013
4000466284	143920	7	7/29/2022	8/9/2022	11	0.000%	0.0000
4000466285	144567	12,429	7/29/2022	8/9/2022	11	0.003%	0.0004
4000466287	144794	13,400	7/29/2022	8/9/2022	11	0.004%	0.0004
4000466288	144878	2,716	7/29/2022	8/9/2022	11	0.001%	0.0001
4000466291	145093	2,020	7/29/2022	8/9/2022	11	0.001%	0.0001
4000466372	11577	1,890	8/1/2022	8/12/2022	11	0.000%	0.0001
4000466373	13911	3,955	8/1/2022	8/12/2022	11	0.001%	0.0001
4000466383	27162	2,941	8/1/2022	8/12/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466384	27982	1,693	8/1/2022	8/12/2022	11	0.000%	0.0000
4000466387	32510	1,540	8/1/2022	8/12/2022	11	0.000%	0.0000
4000466388	32853	630	8/1/2022	8/12/2022	11	0.000%	0.0000
4000466343	6396	27,962	8/1/2022	8/12/2022	11	0.007%	0.0008
4000466344	24856	440	8/1/2022	8/12/2022	11	0.000%	0.0000
4000466498	113857	46,174	8/4/2022	8/15/2022	11	0.012%	0.0013
4000466502	129859	386,320	8/4/2022	8/15/2022	11	0.102%	0.0112
4000466504	143072	44,995	8/4/2022	8/15/2022	11	0.012%	0.0013
4000466505	143577	5,165	8/4/2022	8/15/2022	11	0.001%	0.0001
4000466563	18267	2,851	8/5/2022	8/16/2022	11	0.001%	0.0001
4000466576	34341	7,000	8/5/2022	8/16/2022	11	0.002%	0.0002
4000466578	117331	4,389	8/5/2022	8/16/2022	11	0.001%	0.0001
4000466527	4765	4,850	8/5/2022	8/16/2022	11	0.001%	0.0001
4000466531	27094	12,095	8/5/2022	8/16/2022	11	0.003%	0.0004
4000466534	105195	9,516	8/5/2022	8/16/2022	11	0.003%	0.0003
4000466536	116384	593	8/5/2022	8/16/2022	11	0.000%	0.0000
4000466551	143312	64,628	8/5/2022	8/16/2022	11	0.017%	0.0019
4000466552	143340	11,494	8/5/2022	8/16/2022	11	0.003%	0.0003
4000466554	143659	5,173	8/5/2022	8/16/2022	11	0.001%	0.0002
4000466555	143920	8	8/5/2022	8/16/2022	11	0.000%	0.0000
4000466561	144567	8,000	8/5/2022	8/16/2022	11	0.002%	0.0002
4000466594	11474	2,225	8/8/2022	8/19/2022	11	0.001%	0.0001
4000466609	27962	456	8/8/2022	8/19/2022	11	0.000%	0.0000
4000466581	104872	41	8/8/2022	8/19/2022	11	0.000%	0.0000
4000466767	34658	3,000	8/11/2022	8/22/2022	11	0.001%	0.0001
4000466730	104509	11,478	8/11/2022	8/22/2022	11	0.003%	0.0003
4000466733	108092	5,100	8/11/2022	8/22/2022	11	0.001%	0.0001
4000466734	125742	5,108	8/11/2022	8/22/2022	11	0.001%	0.0001
4000466739	143072	991	8/11/2022	8/22/2022	11	0.000%	0.0000
4000466744	144663	203,308	8/11/2022	8/22/2022	11	0.054%	0.0059
4000466806	18267	3,640	8/12/2022	8/23/2022	11	0.001%	0.0001
4000466813	34064	282	8/12/2022	8/23/2022	11	0.000%	0.0000
4000466818	105195	4,800	8/12/2022	8/23/2022	11	0.001%	0.0001
4000466819	117331	42,535	8/12/2022	8/23/2022	11	0.011%	0.0012
4000466770	9986	550,741	8/12/2022	8/23/2022	11	0.145%	0.0160
4000466772	27094	7,063	8/12/2022	8/23/2022	11	0.002%	0.0002
4000466774	101283	5,592	8/12/2022	8/23/2022	11	0.001%	0.0002
4000466777	105195	10,497	8/12/2022	8/23/2022	11	0.003%	0.0003
4000466778	106840	39	8/12/2022	8/23/2022	11	0.000%	0.0000
4000466783	118807	26	8/12/2022	8/23/2022	11	0.000%	0.0000
4000466787	134862	953,002	8/12/2022	8/23/2022	11	0.251%	0.0276
4000466791	142942	23,573	8/12/2022	8/23/2022	11	0.006%	0.0007
4000466795	143312	18,914	8/12/2022	8/23/2022	11	0.005%	0.0005
4000466796	143340	26,972	8/12/2022	8/23/2022	11	0.007%	0.0008
4000466797	143477	50,582	8/12/2022	8/23/2022	11	0.013%	0.0015
4000466800	143584	13,958	8/12/2022	8/23/2022	11	0.004%	0.0004
4000466801	144567	14,759	8/12/2022	8/23/2022	11	0.004%	0.0004
4000466802	144567	13,701	8/12/2022	8/23/2022	11	0.004%	0.0004
4000466837	11427	4,050	8/15/2022	8/26/2022	11	0.001%	0.0001
4000466845	26643	1,572	8/15/2022	8/26/2022	11	0.000%	0.0000
4000466943	26256	5,125	8/18/2022	8/29/2022	11	0.001%	0.0001
4000466953	132507	12,241	8/18/2022	8/29/2022	11	0.003%	0.0004
4000466959	142942	1,360	8/18/2022	8/29/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466960	143072	1,499	8/18/2022	8/29/2022	11	0.000%	0.0000
4000467010	11305	1,312	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467015	18267	29,422	8/19/2022	8/30/2022	11	0.008%	0.0009
4000467017	24383	1,675	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467018	24825	510	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467022	26659	1,122	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467026	33956	5,829	8/19/2022	8/30/2022	11	0.002%	0.0002
4000467027	34064	174	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467028	34341	1,325	8/19/2022	8/30/2022	11	0.000%	0.0000
4000466978	30580	8,020	8/19/2022	8/30/2022	11	0.002%	0.0002
4000466981	103392	16	8/19/2022	8/30/2022	11	0.000%	0.0000
4000466984	105195	9,779	8/19/2022	8/30/2022	11	0.003%	0.0003
4000466991	130315	39	8/19/2022	8/30/2022	11	0.000%	0.0000
4000466992	134862	346,045	8/19/2022	8/30/2022	11	0.091%	0.0100
4000466993	139713	38,310	8/19/2022	8/30/2022	11	0.010%	0.0011
4000466994	141256	72	8/19/2022	8/30/2022	11	0.000%	0.0000
4000466999	143111	5,000	8/19/2022	8/30/2022	11	0.001%	0.0001
4000467000	143463	30,360	8/19/2022	8/30/2022	11	0.008%	0.0009
4000467004	144546	1,366	8/19/2022	8/30/2022	11	0.000%	0.0000
4000467005	144567	16,908	8/19/2022	8/30/2022	11	0.004%	0.0005
4000467006	144627	12,659	8/19/2022	8/30/2022	11	0.003%	0.0004
4000467007	144816	2,877	8/19/2022	8/30/2022	11	0.001%	0.0001
4000467035	32947	62,462	8/19/2022	8/30/2022	11	0.016%	0.0018
4000467039	32972	8,273	8/19/2022	8/30/2022	11	0.002%	0.0002
4000467082	25905	5,900	8/22/2022	9/2/2022	11	0.002%	0.0002
4000467085	27013	2,791	8/22/2022	9/2/2022	11	0.001%	0.0001
4000467072	126928	27	8/22/2022	9/2/2022	11	0.000%	0.0000
4000467073	126928	219	8/22/2022	9/2/2022	11	0.000%	0.0000
4000467212	125742	8,840	8/26/2022	9/6/2022	11	0.002%	0.0003
4000467215	137204	11,287	8/26/2022	9/6/2022	11	0.003%	0.0003
4000467217	141858	2,560	8/26/2022	9/6/2022	11	0.001%	0.0001
4000467218	142635	8,684	8/26/2022	9/6/2022	11	0.002%	0.0003
4000467219	142700	10,026	8/26/2022	9/6/2022	11	0.003%	0.0003
4000467221	143072	71,928	8/26/2022	9/6/2022	11	0.019%	0.0021
4000467251	32939	70,302	8/26/2022	9/6/2022	11	0.019%	0.0020
4000467255	33042	33,214	8/26/2022	9/6/2022	11	0.009%	0.0010
4000467258	33071	345,455	8/26/2022	9/6/2022	11	0.091%	0.0100
4000467259	33089	65,841	8/26/2022	9/6/2022	11	0.017%	0.0019
4000467260	33094	9,215	8/26/2022	9/6/2022	11	0.002%	0.0003
4000467262	33123	1,503	8/26/2022	9/6/2022	11	0.000%	0.0000
4000467263	112304	20,965	8/26/2022	9/6/2022	11	0.006%	0.0006
4000467282	27013	1,100	8/29/2022	9/9/2022	11	0.000%	0.0000
4000467264	6396	26,762	8/29/2022	9/9/2022	11	0.007%	0.0008
4000467265	6396	15,654	8/29/2022	9/9/2022	11	0.004%	0.0005
4000467270	119251	6,624	8/29/2022	9/9/2022	11	0.002%	0.0002
4000467272	123042	17,393	8/29/2022	9/9/2022	11	0.005%	0.0005
4000467280	145295	2,710	8/29/2022	9/9/2022	11	0.001%	0.0001
4000467424	11536	2,620	9/1/2022	9/12/2022	11	0.001%	0.0001
4000467427	26297	24,168	9/1/2022	9/12/2022	11	0.006%	0.0007
4000467428	26338	896	9/1/2022	9/12/2022	11	0.000%	0.0000
4000467432	26588	13,400	9/1/2022	9/12/2022	11	0.004%	0.0004
4000467435	26674	7,000	9/1/2022	9/12/2022	11	0.002%	0.0002
4000467436	27013	23,699	9/1/2022	9/12/2022	11	0.006%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467439	29469	8,280	9/1/2022	9/12/2022	11	0.002%	0.0002
4000467442	33956	792	9/1/2022	9/12/2022	11	0.000%	0.0000
4000467395	6031	189	9/1/2022	9/12/2022	11	0.000%	0.0000
4000467410	142642	5,115	9/1/2022	9/12/2022	11	0.001%	0.0001
4000467421	145222	1,840	9/1/2022	9/12/2022	11	0.000%	0.0001
4000467520	26604	25,965	9/2/2022	9/13/2022	11	0.007%	0.0008
4000467530	33956	22,870	9/2/2022	9/13/2022	11	0.006%	0.0007
4000467533	34658	7,500	9/2/2022	9/13/2022	11	0.002%	0.0002
4000467535	117331	3,336	9/2/2022	9/13/2022	11	0.001%	0.0001
4000467448	4502	14,476	9/2/2022	9/13/2022	11	0.004%	0.0004
4000467451	7214	241,704	9/2/2022	9/13/2022	11	0.064%	0.0070
4000467452	9145	5,050	9/2/2022	9/13/2022	11	0.001%	0.0001
4000467457	27094	13,689	9/2/2022	9/13/2022	11	0.004%	0.0004
4000467459	103392	289	9/2/2022	9/13/2022	11	0.000%	0.0000
4000467463	116384	127	9/2/2022	9/13/2022	11	0.000%	0.0000
4000467466	126047	1,143	9/2/2022	9/13/2022	11	0.000%	0.0000
4000467469	133414	9,792	9/2/2022	9/13/2022	11	0.003%	0.0003
4000467470	134862	1,765,278	9/2/2022	9/13/2022	11	0.466%	0.0512
4000467475	141025	18,000	9/2/2022	9/13/2022	11	0.005%	0.0005
4000467476	141370	13,250	9/2/2022	9/13/2022	11	0.003%	0.0004
4000467484	142874	12,939	9/2/2022	9/13/2022	11	0.003%	0.0004
4000467485	142926	23,020	9/2/2022	9/13/2022	11	0.006%	0.0007
4000467487	143072	145,439	9/2/2022	9/13/2022	11	0.038%	0.0042
4000467488	143111	3,000	9/2/2022	9/13/2022	11	0.001%	0.0001
4000467491	143400	3,000	9/2/2022	9/13/2022	11	0.001%	0.0001
4000467504	144773	625	9/2/2022	9/13/2022	11	0.000%	0.0000
4000467615	25987	1,600	9/8/2022	9/19/2022	11	0.000%	0.0000
4000467618	34064	468	9/8/2022	9/19/2022	11	0.000%	0.0000
4000467621	135537	45,878	9/8/2022	9/19/2022	11	0.012%	0.0013
4000467591	103404	51	9/8/2022	9/19/2022	11	0.000%	0.0000
4000467606	144519	8,677	9/8/2022	9/19/2022	11	0.002%	0.0003
4000467608	145212	50,135	9/8/2022	9/19/2022	11	0.013%	0.0015
4000467656	18518	3,000	9/9/2022	9/20/2022	11	0.001%	0.0001
4000467663	34064	133	9/9/2022	9/20/2022	11	0.000%	0.0000
4000467666	34658	5,000	9/9/2022	9/20/2022	11	0.001%	0.0001
4000467667	117331	2,289	9/9/2022	9/20/2022	11	0.001%	0.0001
4000467622	4502	14,617	9/9/2022	9/20/2022	11	0.004%	0.0004
4000467627	116384	250	9/9/2022	9/20/2022	11	0.000%	0.0000
4000467639	143463	28,980	9/9/2022	9/20/2022	11	0.008%	0.0008
4000467641	143659	5,946	9/9/2022	9/20/2022	11	0.002%	0.0002
4000467644	144567	360	9/9/2022	9/20/2022	11	0.000%	0.0000
4000467645	144567	15,424	9/9/2022	9/20/2022	11	0.004%	0.0004
4000467646	144567	15,969	9/9/2022	9/20/2022	11	0.004%	0.0005
4000467647	144567	16,948	9/9/2022	9/20/2022	11	0.004%	0.0005
4000467648	144816	13,236	9/9/2022	9/20/2022	11	0.003%	0.0004
4000467671	107927	10,000	9/12/2022	9/23/2022	11	0.003%	0.0003
4000467676	137512	67,500	9/12/2022	9/23/2022	11	0.018%	0.0020
4000467817	25599	2,675	9/15/2022	9/26/2022	11	0.001%	0.0001
4000467818	25808	480	9/15/2022	9/26/2022	11	0.000%	0.0000
4000467831	124943	950	9/15/2022	9/26/2022	11	0.000%	0.0000
4000467833	135537	117,448	9/15/2022	9/26/2022	11	0.031%	0.0034
4000467789	107047	21,560	9/15/2022	9/26/2022	11	0.006%	0.0006
4000467799	134862	62,769	9/15/2022	9/26/2022	11	0.017%	0.0018

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467802	141583	138	9/15/2022	9/26/2022	11	0.000%	0.0000
4000467803	142311	516	9/15/2022	9/26/2022	11	0.000%	0.0000
4000467881	34341	1,325	9/16/2022	9/27/2022	11	0.000%	0.0000
4000467883	34658	2,500	9/16/2022	9/27/2022	11	0.001%	0.0001
4000467885	117331	5,630	9/16/2022	9/27/2022	11	0.001%	0.0002
4000467834	4502	13,257	9/16/2022	9/27/2022	11	0.003%	0.0004
4000467835	4765	1,500	9/16/2022	9/27/2022	11	0.000%	0.0000
4000467836	7214	888,792	9/16/2022	9/27/2022	11	0.234%	0.0258
4000467839	27094	8,829	9/16/2022	9/27/2022	11	0.002%	0.0003
4000467840	30475	43,841	9/16/2022	9/27/2022	11	0.012%	0.0013
4000467841	32842	4,511	9/16/2022	9/27/2022	11	0.001%	0.0001
4000467845	118807	794	9/16/2022	9/27/2022	11	0.000%	0.0000
4000467849	134862	997,758	9/16/2022	9/27/2022	11	0.263%	0.0289
4000467854	142942	23,858	9/16/2022	9/27/2022	11	0.006%	0.0007
4000467856	143111	3,200	9/16/2022	9/27/2022	11	0.001%	0.0001
4000467858	144084	53,440	9/16/2022	9/27/2022	11	0.014%	0.0016
4000467905	25131	1,710	9/19/2022	9/30/2022	11	0.000%	0.0000
4000467910	33203	748	9/19/2022	9/30/2022	11	0.000%	0.0000
4000467892	116902	14,106	9/19/2022	9/30/2022	11	0.004%	0.0004
4000468012	25905	22,800	9/22/2022	10/3/2022	11	0.006%	0.0007
4000468014	27962	7,124	9/22/2022	10/3/2022	11	0.002%	0.0002
4000467987	26256	3,375	9/22/2022	10/3/2022	11	0.001%	0.0001
4000467995	126928	33	9/22/2022	10/3/2022	11	0.000%	0.0000
4000467996	126928	141	9/22/2022	10/3/2022	11	0.000%	0.0000
4000468078	26490	1,014	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468088	34064	26	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468091	34658	2,500	9/23/2022	10/4/2022	11	0.001%	0.0001
4000468093	117331	359	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468029	12081	1,105	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468034	30580	5,861	9/23/2022	10/4/2022	11	0.002%	0.0002
4000468044	116051	100	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468046	118807	33	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468050	132094	875	9/23/2022	10/4/2022	11	0.000%	0.0000
4000468052	134862	1,143,746	9/23/2022	10/4/2022	11	0.302%	0.0332
4000468063	143477	22,628	9/23/2022	10/4/2022	11	0.006%	0.0007
4000468119	26323	2,580	9/26/2022	10/7/2022	11	0.001%	0.0001
4000468096	6396	8,921	9/26/2022	10/7/2022	11	0.002%	0.0003
4000468116	145324	390	9/26/2022	10/7/2022	11	0.000%	0.0000
4000468328	108092	19,665	9/30/2022	10/11/2022	11	0.005%	0.0006
4000468332	116384	399	9/30/2022	10/11/2022	11	0.000%	0.0000
4000468335	117392	9,953	9/30/2022	10/11/2022	11	0.003%	0.0003
4000468337	125742	36,438	9/30/2022	10/11/2022	11	0.010%	0.0011
4000468349	141114	5,382	9/30/2022	10/11/2022	11	0.001%	0.0002
4000468351	141822	6,898	9/30/2022	10/11/2022	11	0.002%	0.0002
4000468357	142635	8,529	9/30/2022	10/11/2022	11	0.002%	0.0002
4000468373	143796	93,335	9/30/2022	10/11/2022	11	0.025%	0.0027
4000468449	24113	276	10/3/2022	10/14/2022	11	0.000%	0.0000
4000468452	25987	2,200	10/3/2022	10/14/2022	11	0.001%	0.0001
4000468460	26642	2,991	10/3/2022	10/14/2022	11	0.001%	0.0001
4000468462	26674	1,680	10/3/2022	10/14/2022	11	0.000%	0.0000
4000468463	27013	25,811	10/3/2022	10/14/2022	11	0.007%	0.0007
4000468427	32869	15	10/3/2022	10/14/2022	11	0.000%	0.0000
4000468437	143880	1,800	10/3/2022	10/14/2022	11	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468443	145295	1,355	10/3/2022	10/14/2022	11	0.000%	0.0000
4000468525	26577	500	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468526	26643	1,175	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468527	26679	1,125	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468528	27013	84	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468529	28530	31,979	10/6/2022	10/17/2022	11	0.008%	0.0009
4000468533	34341	49	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468505	101853	651	10/6/2022	10/17/2022	11	0.000%	0.0000
4000468588	26604	4,990	10/7/2022	10/18/2022	11	0.001%	0.0001
4000468609	34658	2,500	10/7/2022	10/18/2022	11	0.001%	0.0001
4000468611	117331	16,138	10/7/2022	10/18/2022	11	0.004%	0.0005
4000468612	124943	760	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468544	34888	282	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468546	100577	578	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468551	104195	46	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468557	116384	113	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468562	143072	136,271	10/7/2022	10/18/2022	11	0.036%	0.0040
4000468563	143111	2,400	10/7/2022	10/18/2022	11	0.001%	0.0001
4000468564	143340	4,443	10/7/2022	10/18/2022	11	0.001%	0.0001
4000468565	143463	33,120	10/7/2022	10/18/2022	11	0.009%	0.0010
4000468566	143577	5,723	10/7/2022	10/18/2022	11	0.002%	0.0002
4000468567	143659	55,592	10/7/2022	10/18/2022	11	0.015%	0.0016
4000468568	143659	77,449	10/7/2022	10/18/2022	11	0.020%	0.0022
4000468570	143920	7	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468574	144567	81,968	10/7/2022	10/18/2022	11	0.022%	0.0024
4000468575	144724	1,130,289	10/7/2022	10/18/2022	11	0.298%	0.0328
4000468576	145141	496	10/7/2022	10/18/2022	11	0.000%	0.0000
4000468746	36403	967	10/13/2022	10/24/2022	11	0.000%	0.0000
4000468749	110291	18,998	10/13/2022	10/24/2022	11	0.005%	0.0006
4000468750	110291	13,695	10/13/2022	10/24/2022	11	0.004%	0.0004
4000468752	125742	3,320	10/13/2022	10/24/2022	11	0.001%	0.0001
4000468753	133414	2,693	10/13/2022	10/24/2022	11	0.001%	0.0001
4000468754	142635	52,196	10/13/2022	10/24/2022	11	0.014%	0.0015
4000468755	142700	6,060	10/13/2022	10/24/2022	11	0.002%	0.0002
4000468758	143577	4,501	10/13/2022	10/24/2022	11	0.001%	0.0001
4000468822	18267	13,283	10/14/2022	10/25/2022	11	0.004%	0.0004
4000468823	24281	28,639	10/14/2022	10/25/2022	11	0.008%	0.0008
4000468830	28474	599	10/14/2022	10/25/2022	11	0.000%	0.0000
4000468838	33975	19,780	10/14/2022	10/25/2022	11	0.005%	0.0006
4000468839	33984	48,196	10/14/2022	10/25/2022	11	0.013%	0.0014
4000468840	34064	75	10/14/2022	10/25/2022	11	0.000%	0.0000
4000468845	34658	2,500	10/14/2022	10/25/2022	11	0.001%	0.0001
4000468846	117331	1,900	10/14/2022	10/25/2022	11	0.001%	0.0001
4000468784	4502	3,250	10/14/2022	10/25/2022	11	0.001%	0.0001
4000468785	4502	12,476	10/14/2022	10/25/2022	11	0.003%	0.0004
4000468789	26256	5,250	10/14/2022	10/25/2022	11	0.001%	0.0002
4000468793	104872	186	10/14/2022	10/25/2022	11	0.000%	0.0000
4000468794	105195	24,173	10/14/2022	10/25/2022	11	0.006%	0.0007
4000468799	134862	47,405	10/14/2022	10/25/2022	11	0.013%	0.0014
4000468808	143111	6,200	10/14/2022	10/25/2022	11	0.002%	0.0002
4000468809	143312	9,587	10/14/2022	10/25/2022	11	0.003%	0.0003
4000468811	143573	179,940	10/14/2022	10/25/2022	11	0.047%	0.0052
4000468814	144567	6,865	10/14/2022	10/25/2022	11	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468815	144567	13,578	10/14/2022	10/25/2022	11	0.004%	0.0004
4000468816	144567	20,838	10/14/2022	10/25/2022	11	0.005%	0.0006
4000468817	144816	5,090	10/14/2022	10/25/2022	11	0.001%	0.0001
4000468818	145193	5,060	10/14/2022	10/25/2022	11	0.001%	0.0001
4000468877	25599	2,051	10/17/2022	10/28/2022	11	0.001%	0.0001
4000468878	25808	3,660	10/17/2022	10/28/2022	11	0.001%	0.0001
4000468862	126928	37	10/17/2022	10/28/2022	11	0.000%	0.0000
4000469060	24259	14,454	10/20/2022	10/31/2022	11	0.004%	0.0004
4000469064	30475	46,546	10/20/2022	10/31/2022	11	0.012%	0.0014
4000469065	30475	51,460	10/20/2022	10/31/2022	11	0.014%	0.0015
4000469066	30475	58,766	10/20/2022	10/31/2022	11	0.015%	0.0017
4000469071	105195	18,540	10/20/2022	10/31/2022	11	0.005%	0.0005
4000469036	100103	197	10/20/2022	10/31/2022	11	0.000%	0.0000
4000469047	133414	627	10/20/2022	10/31/2022	11	0.000%	0.0000
4000469049	142926	17,697	10/20/2022	10/31/2022	11	0.005%	0.0005
4000469050	142942	385	10/20/2022	10/31/2022	11	0.000%	0.0000
4000469121	33956	660	10/21/2022	11/1/2022	11	0.000%	0.0000
4000469122	34064	244	10/21/2022	11/1/2022	11	0.000%	0.0000
4000469123	34341	24,425	10/21/2022	11/1/2022	11	0.006%	0.0007
4000469126	34658	2,500	10/21/2022	11/1/2022	11	0.001%	0.0001
4000469128	117331	12,000	10/21/2022	11/1/2022	11	0.003%	0.0003
4000469076	7214	498,109	10/21/2022	11/1/2022	11	0.131%	0.0145
4000469078	22704	13,100	10/21/2022	11/1/2022	11	0.003%	0.0004
4000469080	27094	2,649	10/21/2022	11/1/2022	11	0.001%	0.0001
4000469090	126120	16,382	10/21/2022	11/1/2022	11	0.004%	0.0005
4000469092	132094	7,925	10/21/2022	11/1/2022	11	0.002%	0.0002
4000469094	139982	9,494	10/21/2022	11/1/2022	11	0.003%	0.0003
4000469096	142394	22,186	10/21/2022	11/1/2022	11	0.006%	0.0006
4000469099	142942	22,308	10/21/2022	11/1/2022	11	0.006%	0.0006
4000469101	143111	6,000	10/21/2022	11/1/2022	11	0.002%	0.0002
4000469103	144084	6,200	10/21/2022	11/1/2022	11	0.002%	0.0002
4000469104	144816	960	10/21/2022	11/1/2022	11	0.000%	0.0000
4000469158	8392	14,755	10/24/2022	11/4/2022	11	0.004%	0.0004
4000469161	27994	1,760	10/24/2022	11/4/2022	11	0.000%	0.0001
4000469293	9673	925	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469301	25905	3,900	10/27/2022	11/7/2022	11	0.001%	0.0001
4000469305	26490	697	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469306	26604	31,770	10/27/2022	11/7/2022	11	0.008%	0.0009
4000469307	26639	12,690	10/27/2022	11/7/2022	11	0.003%	0.0004
4000469308	26642	2,663	10/27/2022	11/7/2022	11	0.001%	0.0001
4000469314	32875	850	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469265	24825	7,184	10/27/2022	11/7/2022	11	0.002%	0.0002
4000469267	103603	2,927	10/27/2022	11/7/2022	11	0.001%	0.0001
4000469271	111669	18	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469273	125349	750	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469274	125742	5,680	10/27/2022	11/7/2022	11	0.001%	0.0002
4000469276	125960	277	10/27/2022	11/7/2022	11	0.000%	0.0000
4000469279	134862	193,819	10/27/2022	11/7/2022	11	0.051%	0.0056
4000469326	32962	7,626	10/27/2022	11/7/2022	11	0.002%	0.0002
4000469363	5673	6,800	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469386	30257	7,824	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469389	33956	845	10/28/2022	11/8/2022	11	0.000%	0.0000
4000469390	34064	125	10/28/2022	11/8/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469391	34341	7,000	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469397	117331	10,000	10/28/2022	11/8/2022	11	0.003%	0.0003
4000469330	26256	6,000	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469334	103392	267	10/28/2022	11/8/2022	11	0.000%	0.0000
4000469340	113448	10,913	10/28/2022	11/8/2022	11	0.003%	0.0003
4000469341	116384	112	10/28/2022	11/8/2022	11	0.000%	0.0000
4000469342	125742	44	10/28/2022	11/8/2022	11	0.000%	0.0000
4000469347	138494	3,400	10/28/2022	11/8/2022	11	0.001%	0.0001
4000469351	143111	6,000	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469352	143312	60,681	10/28/2022	11/8/2022	11	0.016%	0.0018
4000469353	143338	80,190	10/28/2022	11/8/2022	11	0.021%	0.0023
4000469354	143436	43,776	10/28/2022	11/8/2022	11	0.012%	0.0013
4000469356	143584	354,681	10/28/2022	11/8/2022	11	0.094%	0.0103
4000469358	143637	3,750	10/28/2022	11/8/2022	11	0.001%	0.0001
4000469360	144567	6,768	10/28/2022	11/8/2022	11	0.002%	0.0002
4000469361	144982	2,791	10/28/2022	11/8/2022	11	0.001%	0.0001
4000469580	14060	900	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469583	26577	1,800	11/3/2022	11/14/2022	11	0.000%	0.0001
4000469586	26674	1,120	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469592	33747	1,116	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469597	117331	8,601	11/3/2022	11/14/2022	11	0.002%	0.0002
4000469550	15871	6,317	11/3/2022	11/14/2022	11	0.002%	0.0002
4000469551	26958	1,233	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469554	108092	5,130	11/3/2022	11/14/2022	11	0.001%	0.0001
4000469557	116384	90	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469560	134862	17,216	11/3/2022	11/14/2022	11	0.005%	0.0005
4000469561	138494	3,400	11/3/2022	11/14/2022	11	0.001%	0.0001
4000469562	138862	155	11/3/2022	11/14/2022	11	0.000%	0.0000
4000469571	144567	9,000	11/3/2022	11/14/2022	11	0.002%	0.0003
4000469572	144986	4,000	11/3/2022	11/14/2022	11	0.001%	0.0001
4000469574	145067	2,200	11/3/2022	11/14/2022	11	0.001%	0.0001
4000469640	25083	6,634	11/4/2022	11/15/2022	11	0.002%	0.0002
4000469642	25599	675	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469647	26659	43,635	11/4/2022	11/15/2022	11	0.012%	0.0013
4000469656	33956	8,508	11/4/2022	11/15/2022	11	0.002%	0.0002
4000469657	34341	71	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469659	34658	5,000	11/4/2022	11/15/2022	11	0.001%	0.0001
4000469660	124943	1,045	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469601	4502	4,010	11/4/2022	11/15/2022	11	0.001%	0.0001
4000469605	7214	272,151	11/4/2022	11/15/2022	11	0.072%	0.0079
4000469606	12081	1,283	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469614	105195	7,426	11/4/2022	11/15/2022	11	0.002%	0.0002
4000469617	116384	59	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469620	132094	100	11/4/2022	11/15/2022	11	0.000%	0.0000
4000469627	143072	21,243	11/4/2022	11/15/2022	11	0.006%	0.0006
4000469628	143111	3,400	11/4/2022	11/15/2022	11	0.001%	0.0001
4000469631	144982	2,407	11/4/2022	11/15/2022	11	0.001%	0.0001
4000469633	145455	5,500	11/4/2022	11/15/2022	11	0.001%	0.0002
4000469688	134485	6,090	11/7/2022	11/18/2022	11	0.002%	0.0002
4000469664	104872	849	11/7/2022	11/18/2022	11	0.000%	0.0000
4000469822	28484	4,800	11/10/2022	11/21/2022	11	0.001%	0.0001
4000469831	133795	11,499	11/10/2022	11/21/2022	11	0.003%	0.0003
4000469785	116384	614	11/10/2022	11/21/2022	11	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469788	125742	19,622	11/10/2022	11/21/2022	11	0.005%	0.0006
4000469791	133926	974	11/10/2022	11/21/2022	11	0.000%	0.0000
4000469793	138494	91,480	11/10/2022	11/21/2022	11	0.024%	0.0027
4000469800	143243	287,232	11/10/2022	11/21/2022	11	0.076%	0.0083
4000469804	143577	3,050	11/10/2022	11/21/2022	11	0.001%	0.0001
4000469860	25809	2,288	11/14/2022	11/25/2022	11	0.001%	0.0001
4000469862	26453	17,430	11/14/2022	11/25/2022	11	0.005%	0.0005
4000469868	126165	4,535	11/14/2022	11/25/2022	11	0.001%	0.0001
4000469837	5089	3,240	11/14/2022	11/25/2022	11	0.001%	0.0001
4000469965	115761	48	11/17/2022	11/28/2022	11	0.000%	0.0000
4000469966	125742	11,904	11/17/2022	11/28/2022	11	0.003%	0.0003
4000469969	142635	3,075	11/17/2022	11/28/2022	11	0.001%	0.0001
4000469971	142700	26,038	11/17/2022	11/28/2022	11	0.007%	0.0008
4000469974	143577	5,798	11/17/2022	11/28/2022	11	0.002%	0.0002
4000469975	143796	2,116	11/17/2022	11/28/2022	11	0.001%	0.0001
4000469976	144097	3,894,916	11/17/2022	11/28/2022	11	1.027%	0.1130
4000470026	18267	17,752	11/18/2022	11/29/2022	11	0.005%	0.0005
4000470031	24825	1,940	11/18/2022	11/29/2022	11	0.001%	0.0001
4000470037	26604	5,515	11/18/2022	11/29/2022	11	0.001%	0.0002
4000470042	28474	2,427	11/18/2022	11/29/2022	11	0.001%	0.0001
4000470047	34335	450	11/18/2022	11/29/2022	11	0.000%	0.0000
4000470048	34341	24,425	11/18/2022	11/29/2022	11	0.006%	0.0007
4000470050	34658	2,500	11/18/2022	11/29/2022	11	0.001%	0.0001
4000469994	4502	1,795	11/18/2022	11/29/2022	11	0.000%	0.0001
4000469995	12081	267	11/18/2022	11/29/2022	11	0.000%	0.0000
4000469998	27094	19,424	11/18/2022	11/29/2022	11	0.005%	0.0006
4000470006	105195	8,551	11/18/2022	11/29/2022	11	0.002%	0.0002
4000470010	132094	288	11/18/2022	11/29/2022	11	0.000%	0.0000
4000470011	134862	832,647	11/18/2022	11/29/2022	11	0.220%	0.0242
4000470014	142942	23,733	11/18/2022	11/29/2022	11	0.006%	0.0007
4000470016	143111	5,400	11/18/2022	11/29/2022	11	0.001%	0.0002
4000470017	143243	179,520	11/18/2022	11/29/2022	11	0.047%	0.0052
4000470019	144358	131,419	11/18/2022	11/29/2022	11	0.035%	0.0038
4000470020	144567	3,976	11/18/2022	11/29/2022	11	0.001%	0.0001
4000470021	144982	15,516	11/18/2022	11/29/2022	11	0.004%	0.0005
4000470099	135537	10,375	11/21/2022	12/2/2022	11	0.003%	0.0003
4000470056	107047	24,244	11/21/2022	12/2/2022	11	0.006%	0.0007
4000470076	143426	7,042	11/21/2022	12/2/2022	11	0.002%	0.0002
4000470085	116971	3,000	11/21/2022	12/2/2022	11	0.001%	0.0001
4000470256	25131	380	11/28/2022	12/9/2022	11	0.000%	0.0000
4000470264	26639	2,025	11/28/2022	12/9/2022	11	0.001%	0.0001
4000470268	27068	3,306	11/28/2022	12/9/2022	11	0.001%	0.0001
4000470272	28619	11,200	11/28/2022	12/9/2022	11	0.003%	0.0003
4000470242	143502	851	11/28/2022	12/9/2022	11	0.000%	0.0000
4000470244	144097	5,545,808	11/28/2022	12/9/2022	11	1.463%	0.1609
4000470246	145240	5,508	11/28/2022	12/9/2022	11	0.001%	0.0002
4000470431	9673	7,450	12/1/2022	12/12/2022	11	0.002%	0.0002
4000470436	25173	5,280	12/1/2022	12/12/2022	11	0.001%	0.0002
4000470437	25809	12,115	12/1/2022	12/12/2022	11	0.003%	0.0004
4000470438	27962	912	12/1/2022	12/12/2022	11	0.000%	0.0000
4000470443	32245	9,975	12/1/2022	12/12/2022	11	0.003%	0.0003
4000470445	33203	2,663	12/1/2022	12/12/2022	11	0.001%	0.0001
4000470392	5089	8,094	12/1/2022	12/12/2022	11	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470393	13911	580	12/1/2022	12/12/2022	11	0.000%	0.0000
4000470396	26256	3,750	12/1/2022	12/12/2022	11	0.001%	0.0001
4000470404	113967	2,977	12/1/2022	12/12/2022	11	0.001%	0.0001
4000470413	134862	35,724	12/1/2022	12/12/2022	11	0.009%	0.0010
4000470416	142615	30,546	12/1/2022	12/12/2022	11	0.008%	0.0009
4000470420	142926	27,116	12/1/2022	12/12/2022	11	0.007%	0.0008
4000470422	143072	10,251	12/1/2022	12/12/2022	11	0.003%	0.0003
4000470426	143892	3,000	12/1/2022	12/12/2022	11	0.001%	0.0001
4000470533	33956	3,637	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470534	34064	497	12/2/2022	12/13/2022	11	0.000%	0.0000
4000470536	105195	6,899	12/2/2022	12/13/2022	11	0.002%	0.0002
4000470452	7214	411,182	12/2/2022	12/13/2022	11	0.108%	0.0119
4000470456	36403	4,832	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470460	110291	53,375	12/2/2022	12/13/2022	11	0.014%	0.0015
4000470485	142926	14,702	12/2/2022	12/13/2022	11	0.004%	0.0004
4000470486	142942	22,144	12/2/2022	12/13/2022	11	0.006%	0.0006
4000470490	143270	4,500	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470493	143436	836	12/2/2022	12/13/2022	11	0.000%	0.0000
4000470495	143637	3,750	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470498	144015	10,000	12/2/2022	12/13/2022	11	0.003%	0.0003
4000470502	144510	2,000	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470504	144573	4,000	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470505	144773	625	12/2/2022	12/13/2022	11	0.000%	0.0000
4000470508	144982	46,415	12/2/2022	12/13/2022	11	0.012%	0.0013
4000470513	145059	2,000	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470514	145067	2,200	12/2/2022	12/13/2022	11	0.001%	0.0001
4000470543	104752	2,500	12/5/2022	12/16/2022	11	0.001%	0.0001
4000470669	9121	4,600	12/8/2022	12/19/2022	11	0.001%	0.0001
4000470672	24113	9,453	12/8/2022	12/19/2022	11	0.002%	0.0003
4000470674	25131	760	12/8/2022	12/19/2022	11	0.000%	0.0000
4000470676	26490	4,481	12/8/2022	12/19/2022	11	0.001%	0.0001
4000470659	134862	446,629	12/8/2022	12/19/2022	11	0.118%	0.0130
4000470662	142942	802	12/8/2022	12/19/2022	11	0.000%	0.0000
4000470724	18267	10,460	12/9/2022	12/20/2022	11	0.003%	0.0003
4000470725	24385	1,132	12/9/2022	12/20/2022	11	0.000%	0.0000
4000470737	33956	6,486	12/9/2022	12/20/2022	11	0.002%	0.0002
4000470738	34064	304	12/9/2022	12/20/2022	11	0.000%	0.0000
4000470740	34341	1,325	12/9/2022	12/20/2022	11	0.000%	0.0000
4000470692	4502	8,819	12/9/2022	12/20/2022	11	0.002%	0.0003
4000470693	4765	9,000	12/9/2022	12/20/2022	11	0.002%	0.0003
4000470695	6351	99,300	12/9/2022	12/20/2022	11	0.026%	0.0029
4000470698	27094	10,520	12/9/2022	12/20/2022	11	0.003%	0.0003
4000470700	105195	21,754	12/9/2022	12/20/2022	11	0.006%	0.0006
4000470710	143312	2,346	12/9/2022	12/20/2022	11	0.001%	0.0001
4000470711	143340	1,476,263	12/9/2022	12/20/2022	11	0.389%	0.0428
4000470716	144567	31,365	12/9/2022	12/20/2022	11	0.008%	0.0009
4000470718	144982	3,912	12/9/2022	12/20/2022	11	0.001%	0.0001
4000470720	145479	2,475	12/9/2022	12/20/2022	11	0.001%	0.0001
4000470769	26299	1,296	12/12/2022	12/23/2022	11	0.000%	0.0000
4000470771	26381	11,040	12/12/2022	12/23/2022	11	0.003%	0.0003
4000470743	32869	8,500	12/12/2022	12/23/2022	11	0.002%	0.0002
4000470755	142942	5,909	12/12/2022	12/23/2022	11	0.002%	0.0002
4000470931	112215	2,808	12/16/2022	12/27/2022	11	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470955	141822	8,480	12/16/2022	12/27/2022	11	0.002%	0.0002
4000471050	27994	8,305	12/19/2022	12/30/2022	11	0.002%	0.0002
4000471051	32537	1,870	12/19/2022	12/30/2022	11	0.000%	0.0001
4000471037	143072	2,574	12/19/2022	12/30/2022	11	0.001%	0.0001
4000471229	112215	1,420	12/23/2022	1/3/2023	11	0.000%	0.0000
4000471372	11474	475	12/29/2022	1/9/2023	11	0.000%	0.0000
4000471373	11577	2,468	12/29/2022	1/9/2023	11	0.001%	0.0001
4000471376	18267	4,769	12/29/2022	1/9/2023	11	0.001%	0.0001
4000471381	24259	5,870	12/29/2022	1/9/2023	11	0.002%	0.0002
4000471402	27013	7,847	12/29/2022	1/9/2023	11	0.002%	0.0002
4000471404	28530	36,393	12/29/2022	1/9/2023	11	0.010%	0.0011
4000471343	15871	10,228	12/29/2022	1/9/2023	11	0.003%	0.0003
4000471347	104872	167	12/29/2022	1/9/2023	11	0.000%	0.0000
4000471348	105195	7,474	12/29/2022	1/9/2023	11	0.002%	0.0002
4000471351	116384	13	12/29/2022	1/9/2023	11	0.000%	0.0000
4000471364	144581	6,266	12/29/2022	1/9/2023	11	0.002%	0.0002
4000471508	32245	3,289	12/30/2022	1/10/2023	11	0.001%	0.0001
4000471521	117331	10,000	12/30/2022	1/10/2023	11	0.003%	0.0003
4000471436	123228	63,054	12/30/2022	1/10/2023	11	0.017%	0.0018
4000471439	129387	122,503	12/30/2022	1/10/2023	11	0.032%	0.0036
4000471441	133414	10,607	12/30/2022	1/10/2023	11	0.003%	0.0003
4000471447	142942	35,516	12/30/2022	1/10/2023	11	0.009%	0.0010
4000471459	143637	3,750	12/30/2022	1/10/2023	11	0.001%	0.0001
4000459647	27013	32,368	1/6/2022	1/18/2022	12	0.009%	0.0010
4000459652	34341	3,150	1/6/2022	1/18/2022	12	0.001%	0.0001
4000459657	117331	356,300	1/6/2022	1/18/2022	12	0.094%	0.0113
4000459612	34888	1,440	1/6/2022	1/18/2022	12	0.000%	0.0000
4000459620	121825	34,283	1/6/2022	1/18/2022	12	0.009%	0.0011
4000459621	125742	3,140	1/6/2022	1/18/2022	12	0.001%	0.0001
4000459629	142613	5,616	1/6/2022	1/18/2022	12	0.001%	0.0002
4000459635	144084	17,915	1/6/2022	1/18/2022	12	0.005%	0.0006
4000459641	144681	15,000	1/6/2022	1/18/2022	12	0.004%	0.0005
4000459671	9121	500	1/7/2022	1/19/2022	12	0.000%	0.0000
4000459677	17342	4,253	1/7/2022	1/19/2022	12	0.001%	0.0001
4000459686	26639	14,985	1/7/2022	1/19/2022	12	0.004%	0.0005
4000459689	26659	2,199	1/7/2022	1/19/2022	12	0.001%	0.0001
4000459695	117331	6,600	1/7/2022	1/19/2022	12	0.002%	0.0002
4000459658	10384	4,800	1/7/2022	1/19/2022	12	0.001%	0.0002
4000459661	26213	828	1/7/2022	1/19/2022	12	0.000%	0.0000
4000459662	26453	2,380	1/7/2022	1/19/2022	12	0.001%	0.0001
4000459667	134664	258	1/7/2022	1/19/2022	12	0.000%	0.0000
4000459668	134862	162,071	1/7/2022	1/19/2022	12	0.043%	0.0051
4000459788	11372	3,655	1/12/2022	1/24/2022	12	0.001%	0.0001
4000459798	30475	22,978	1/12/2022	1/24/2022	12	0.006%	0.0007
4000459799	30475	41,810	1/12/2022	1/24/2022	12	0.011%	0.0013
4000459806	126165	565	1/12/2022	1/24/2022	12	0.000%	0.0000
4000459782	143111	3,300	1/12/2022	1/24/2022	12	0.001%	0.0001
4000459860	9001	1,268,657	1/13/2022	1/25/2022	12	0.335%	0.0402
4000459865	25599	3,506	1/13/2022	1/25/2022	12	0.001%	0.0001
4000459868	27013	8,637	1/13/2022	1/25/2022	12	0.002%	0.0003
4000459869	28474	581	1/13/2022	1/25/2022	12	0.000%	0.0000
4000459872	33956	1,818	1/13/2022	1/25/2022	12	0.000%	0.0001
4000459877	117331	36,800	1/13/2022	1/25/2022	12	0.010%	0.0012

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459814	4765	41,804	1/13/2022	1/25/2022	12	0.011%	0.0013
4000459817	9145	33,050	1/13/2022	1/25/2022	12	0.009%	0.0010
4000459820	19534	35,200	1/13/2022	1/25/2022	12	0.009%	0.0011
4000459822	30580	1,242	1/13/2022	1/25/2022	12	0.000%	0.0000
4000459824	34888	1,320	1/13/2022	1/25/2022	12	0.000%	0.0000
4000459825	100577	3,184	1/13/2022	1/25/2022	12	0.001%	0.0001
4000459829	108289	271	1/13/2022	1/25/2022	12	0.000%	0.0000
4000459835	134664	15,402	1/13/2022	1/25/2022	12	0.004%	0.0005
4000459840	141858	42,782	1/13/2022	1/25/2022	12	0.011%	0.0014
4000459845	143436	836	1/13/2022	1/25/2022	12	0.000%	0.0000
4000459882	15871	637	1/14/2022	1/26/2022	12	0.000%	0.0000
4000459891	125742	6,300	1/14/2022	1/26/2022	12	0.002%	0.0002
4000459894	143111	900	1/14/2022	1/26/2022	12	0.000%	0.0000
4000459897	144663	4,900	1/14/2022	1/26/2022	12	0.001%	0.0002
4000459898	144710	66,724	1/14/2022	1/26/2022	12	0.018%	0.0021
4000459900	144737	174,733	1/14/2022	1/26/2022	12	0.046%	0.0055
4000459910	32928	156,782	1/14/2022	1/26/2022	12	0.041%	0.0050
4000459912	32932	12,298	1/14/2022	1/26/2022	12	0.003%	0.0004
4000459913	32933	7,244	1/14/2022	1/26/2022	12	0.002%	0.0002
4000459914	32934	7,025	1/14/2022	1/26/2022	12	0.002%	0.0002
4000459924	32948	6,631	1/14/2022	1/26/2022	12	0.002%	0.0002
4000459926	32950	96,141	1/14/2022	1/26/2022	12	0.025%	0.0030
4000459932	32966	4,963	1/14/2022	1/26/2022	12	0.001%	0.0002
4000459940	32982	16,734	1/14/2022	1/26/2022	12	0.004%	0.0005
4000459942	32986	47,977	1/14/2022	1/26/2022	12	0.013%	0.0015
4000459946	32996	56,800	1/14/2022	1/26/2022	12	0.015%	0.0018
4000459947	32997	38,661	1/14/2022	1/26/2022	12	0.010%	0.0012
4000459950	33001	314,920	1/14/2022	1/26/2022	12	0.083%	0.0100
4000460031	8392	5,558	1/19/2022	1/31/2022	12	0.001%	0.0002
4000460033	20063	7,502	1/19/2022	1/31/2022	12	0.002%	0.0002
4000460042	30475	74,114	1/19/2022	1/31/2022	12	0.020%	0.0023
4000460021	142926	48,400	1/19/2022	1/31/2022	12	0.013%	0.0015
4000460086	25809	2,760	1/20/2022	2/1/2022	12	0.001%	0.0001
4000460058	26312	10,406	1/20/2022	2/1/2022	12	0.003%	0.0003
4000460063	103620	245	1/20/2022	2/1/2022	12	0.000%	0.0000
4000460065	111669	60	1/20/2022	2/1/2022	12	0.000%	0.0000
4000460067	115811	18,000	1/20/2022	2/1/2022	12	0.005%	0.0006
4000460119	26643	8,719	1/21/2022	2/2/2022	12	0.002%	0.0003
4000460122	33354	24,125	1/21/2022	2/2/2022	12	0.006%	0.0008
4000460103	26674	1,960	1/21/2022	2/2/2022	12	0.001%	0.0001
4000460108	103867	7	1/21/2022	2/2/2022	12	0.000%	0.0000
4000460111	116384	648	1/21/2022	2/2/2022	12	0.000%	0.0000
4000460114	125960	269	1/21/2022	2/2/2022	12	0.000%	0.0000
4000460117	144758	11,000	1/21/2022	2/2/2022	12	0.003%	0.0003
4000460295	25173	2,640	1/26/2022	2/7/2022	12	0.001%	0.0001
4000460287	144097	2,945,781	1/26/2022	2/7/2022	12	0.777%	0.0932
4000460424	11372	1,353	1/27/2022	2/8/2022	12	0.000%	0.0000
4000460431	25599	2,892	1/27/2022	2/8/2022	12	0.001%	0.0001
4000460433	26643	16,104	1/27/2022	2/8/2022	12	0.004%	0.0005
4000460437	27994	7,590	1/27/2022	2/8/2022	12	0.002%	0.0002
4000460446	124943	665	1/27/2022	2/8/2022	12	0.000%	0.0000
4000460316	32538	378	1/27/2022	2/8/2022	12	0.000%	0.0000
4000460344	32964	18,350	1/27/2022	2/8/2022	12	0.005%	0.0006

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460345	32977	25,763	1/27/2022	2/8/2022	12	0.007%	0.0008
4000460358	33072	46,050	1/27/2022	2/8/2022	12	0.012%	0.0015
4000460361	33076	39,642	1/27/2022	2/8/2022	12	0.010%	0.0013
4000460376	33097	407,713	1/27/2022	2/8/2022	12	0.108%	0.0129
4000460384	33107	11,688	1/27/2022	2/8/2022	12	0.003%	0.0004
4000460398	33126	77,400	1/27/2022	2/8/2022	12	0.020%	0.0024
4000460411	33139	29,678	1/27/2022	2/8/2022	12	0.008%	0.0009
4000460412	33140	21,878	1/27/2022	2/8/2022	12	0.006%	0.0007
4000460414	33142	9,131	1/27/2022	2/8/2022	12	0.002%	0.0003
4000460416	33145	1,567	1/27/2022	2/8/2022	12	0.000%	0.0000
4000460418	33147	38	1/27/2022	2/8/2022	12	0.000%	0.0000
4000460420	33150	33,324	1/27/2022	2/8/2022	12	0.009%	0.0011
4000460469	11054	1,550	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460470	14060	17,894	1/28/2022	2/9/2022	12	0.005%	0.0006
4000460472	24383	7,315	1/28/2022	2/9/2022	12	0.002%	0.0002
4000460478	27493	6,525	1/28/2022	2/9/2022	12	0.002%	0.0002
4000460479	28474	1,485	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460453	27026	1,000	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460455	103008	42	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460459	116384	154	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460465	143433	3,020	1/28/2022	2/9/2022	12	0.001%	0.0001
4000460467	144794	4,850	1/28/2022	2/9/2022	12	0.001%	0.0002
4000460489	32952	32,331	1/28/2022	2/9/2022	12	0.009%	0.0010
4000460519	33102	20,121	1/28/2022	2/9/2022	12	0.005%	0.0006
4000460521	33104	81,353	1/28/2022	2/9/2022	12	0.021%	0.0026
4000460525	33112	178	1/28/2022	2/9/2022	12	0.000%	0.0000
4000460540	33129	1,668	1/28/2022	2/9/2022	12	0.000%	0.0001
4000460677	26958	2,846	2/2/2022	2/14/2022	12	0.001%	0.0001
4000460745	25938	3,524	2/3/2022	2/15/2022	12	0.001%	0.0001
4000460758	32356	986	2/3/2022	2/15/2022	12	0.000%	0.0000
4000460799	30475	69,434	2/4/2022	2/16/2022	12	0.018%	0.0022
4000460800	30475	72,199	2/4/2022	2/16/2022	12	0.019%	0.0023
4000460801	30475	76,971	2/4/2022	2/16/2022	12	0.020%	0.0024
4000460802	30475	61,017	2/4/2022	2/16/2022	12	0.016%	0.0019
4000460803	30475	62,923	2/4/2022	2/16/2022	12	0.017%	0.0020
4000460804	30475	67,906	2/4/2022	2/16/2022	12	0.018%	0.0021
4000460773	119139	70,000	2/4/2022	2/16/2022	12	0.018%	0.0022
4000460781	143941	10,397	2/4/2022	2/16/2022	12	0.003%	0.0003
4000460786	144900	10,481	2/4/2022	2/16/2022	12	0.003%	0.0003
4000460956	24251	13,920	2/10/2022	2/22/2022	12	0.004%	0.0004
4000460958	25437	6,323	2/10/2022	2/22/2022	12	0.002%	0.0002
4000460966	27389	43,528	2/10/2022	2/22/2022	12	0.011%	0.0014
4000460941	125742	7,500	2/10/2022	2/22/2022	12	0.002%	0.0002
4000460942	130875	480	2/10/2022	2/22/2022	12	0.000%	0.0000
4000460947	142998	3,500	2/10/2022	2/22/2022	12	0.001%	0.0001
4000461033	18267	8,215	2/11/2022	2/23/2022	12	0.002%	0.0003
4000461044	125016	1,479	2/11/2022	2/23/2022	12	0.000%	0.0000
4000460983	4765	34,966	2/11/2022	2/23/2022	12	0.009%	0.0011
4000460990	32842	3,080	2/11/2022	2/23/2022	12	0.001%	0.0001
4000460991	36140	2,895	2/11/2022	2/23/2022	12	0.001%	0.0001
4000460999	104154	352	2/11/2022	2/23/2022	12	0.000%	0.0000
4000461002	105195	3,651	2/11/2022	2/23/2022	12	0.001%	0.0001
4000461003	111669	18	2/11/2022	2/23/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461004	112103	86,751	2/11/2022	2/23/2022	12	0.023%	0.0027
4000461008	118807	2,789	2/11/2022	2/23/2022	12	0.001%	0.0001
4000461014	130163	1,147	2/11/2022	2/23/2022	12	0.000%	0.0000
4000461018	135488	4,780	2/11/2022	2/23/2022	12	0.001%	0.0002
4000461019	137204	13,459	2/11/2022	2/23/2022	12	0.004%	0.0004
4000461020	141583	1,025	2/11/2022	2/23/2022	12	0.000%	0.0000
4000461024	143116	1,067	2/11/2022	2/23/2022	12	0.000%	0.0000
4000461028	144567	16,969	2/11/2022	2/23/2022	12	0.004%	0.0005
4000461029	144567	14,436	2/11/2022	2/23/2022	12	0.004%	0.0005
4000461030	144662	309	2/11/2022	2/23/2022	12	0.000%	0.0000
4000461105	33624	50,932	2/16/2022	2/28/2022	12	0.013%	0.0016
4000461109	104872	232	2/16/2022	2/28/2022	12	0.000%	0.0000
4000461119	121802	1,000	2/16/2022	2/28/2022	12	0.000%	0.0000
4000461139	144881	16,481	2/16/2022	2/28/2022	12	0.004%	0.0005
4000461140	144898	18,930	2/16/2022	2/28/2022	12	0.005%	0.0006
4000461098	121738	3,000	2/16/2022	2/28/2022	12	0.001%	0.0001
4000461183	8392	9,429	2/17/2022	3/1/2022	12	0.002%	0.0003
4000461191	24385	710	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461193	25808	480	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461195	26643	5,421	2/17/2022	3/1/2022	12	0.001%	0.0002
4000461203	32897	700	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461161	15051	932	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461167	32874	656	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461169	102558	22,690	2/17/2022	3/1/2022	12	0.006%	0.0007
4000461174	130875	755	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461177	139089	18	2/17/2022	3/1/2022	12	0.000%	0.0000
4000461245	24251	1,920	2/18/2022	3/2/2022	12	0.001%	0.0001
4000461248	26213	2,622	2/18/2022	3/2/2022	12	0.001%	0.0001
4000461251	27013	283	2/18/2022	3/2/2022	12	0.000%	0.0000
4000461211	15871	3,651	2/18/2022	3/2/2022	12	0.001%	0.0001
4000461226	126627	1,473	2/18/2022	3/2/2022	12	0.000%	0.0000
4000461232	135058	41,510	2/18/2022	3/2/2022	12	0.011%	0.0013
4000461234	140752	914	2/18/2022	3/2/2022	12	0.000%	0.0000
4000461343	13911	48,195	2/23/2022	3/7/2022	12	0.013%	0.0015
4000461354	26363	1,329	2/23/2022	3/7/2022	12	0.000%	0.0000
4000461359	26674	1,400	2/23/2022	3/7/2022	12	0.000%	0.0000
4000461315	19534	21,695	2/23/2022	3/7/2022	12	0.006%	0.0007
4000461329	135057	1,620	2/23/2022	3/7/2022	12	0.000%	0.0001
4000461331	139275	290	2/23/2022	3/7/2022	12	0.000%	0.0000
4000461334	141203	7,313	2/23/2022	3/7/2022	12	0.002%	0.0002
4000461336	142870	19,301	2/23/2022	3/7/2022	12	0.005%	0.0006
4000461396	25908	500	2/24/2022	3/8/2022	12	0.000%	0.0000
4000461381	143463	22,633	2/24/2022	3/8/2022	12	0.006%	0.0007
4000461439	8392	11,680	2/25/2022	3/9/2022	12	0.003%	0.0004
4000461447	24999	1,692	2/25/2022	3/9/2022	12	0.000%	0.0001
4000461449	25173	4,400	2/25/2022	3/9/2022	12	0.001%	0.0001
4000461451	26643	2,497	2/25/2022	3/9/2022	12	0.001%	0.0001
4000461454	27994	1,760	2/25/2022	3/9/2022	12	0.000%	0.0001
4000461466	125016	2,151	2/25/2022	3/9/2022	12	0.001%	0.0001
4000461411	26453	12,560	2/25/2022	3/9/2022	12	0.003%	0.0004
4000461412	26996	4,530	2/25/2022	3/9/2022	12	0.001%	0.0001
4000461416	101853	30,658	2/25/2022	3/9/2022	12	0.008%	0.0010
4000461422	125742	1,926	2/25/2022	3/9/2022	12	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461426	138494	10,530	2/25/2022	3/9/2022	12	0.003%	0.0003
4000461434	143753	126,962	2/25/2022	3/9/2022	12	0.033%	0.0040
4000461591	13534	641	3/2/2022	3/14/2022	12	0.000%	0.0000
4000461593	24383	470	3/2/2022	3/14/2022	12	0.000%	0.0000
4000461596	26639	1,890	3/2/2022	3/14/2022	12	0.000%	0.0001
4000461597	27013	4,059	3/2/2022	3/14/2022	12	0.001%	0.0001
4000461601	34937	12,000	3/2/2022	3/14/2022	12	0.003%	0.0004
4000461542	4502	3,300	3/2/2022	3/14/2022	12	0.001%	0.0001
4000461543	15871	970	3/2/2022	3/14/2022	12	0.000%	0.0000
4000461553	132321	104	3/2/2022	3/14/2022	12	0.000%	0.0000
4000461559	141025	15,000	3/2/2022	3/14/2022	12	0.004%	0.0005
4000461563	141873	16,344	3/2/2022	3/14/2022	12	0.004%	0.0005
4000461566	142162	11,000	3/2/2022	3/14/2022	12	0.003%	0.0003
4000461575	143400	3,000	3/2/2022	3/14/2022	12	0.001%	0.0001
4000461578	143606	224,402	3/2/2022	3/14/2022	12	0.059%	0.0071
4000461579	143807	1,058	3/2/2022	3/14/2022	12	0.000%	0.0000
4000461580	143929	75,124	3/2/2022	3/14/2022	12	0.020%	0.0024
4000461583	144213	10,000	3/2/2022	3/14/2022	12	0.003%	0.0003
4000461584	144270	13,280	3/2/2022	3/14/2022	12	0.004%	0.0004
4000461541	116902	1,675	3/2/2022	3/14/2022	12	0.000%	0.0001
4000461626	24765	1,077	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461627	29469	748	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461606	11260	1,167	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461608	103008	291	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461611	126631	1,699	3/3/2022	3/15/2022	12	0.000%	0.0001
4000461613	134480	417	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461621	144773	625	3/3/2022	3/15/2022	12	0.000%	0.0000
4000461656	11577	3,413	3/4/2022	3/16/2022	12	0.001%	0.0001
4000461662	27013	9,208	3/4/2022	3/16/2022	12	0.002%	0.0003
4000461666	30475	50,073	3/4/2022	3/16/2022	12	0.013%	0.0016
4000461667	30475	56,498	3/4/2022	3/16/2022	12	0.015%	0.0018
4000461669	33747	450	3/4/2022	3/16/2022	12	0.000%	0.0000
4000461635	15871	180	3/4/2022	3/16/2022	12	0.000%	0.0000
4000461741	104872	782	3/9/2022	3/21/2022	12	0.000%	0.0000
4000461744	125536	85	3/9/2022	3/21/2022	12	0.000%	0.0000
4000461843	26643	1,382	3/11/2022	3/23/2022	12	0.000%	0.0000
4000461844	30475	98,001	3/11/2022	3/23/2022	12	0.026%	0.0031
4000461845	30475	72,215	3/11/2022	3/23/2022	12	0.019%	0.0023
4000461850	34531	4,080	3/11/2022	3/23/2022	12	0.001%	0.0001
4000461817	103392	331	3/11/2022	3/23/2022	12	0.000%	0.0000
4000461830	142926	45,319	3/11/2022	3/23/2022	12	0.012%	0.0014
4000461941	8392	820	3/16/2022	3/28/2022	12	0.000%	0.0000
4000461944	18267	4,254	3/16/2022	3/28/2022	12	0.001%	0.0001
4000461939	144881	16,893	3/16/2022	3/28/2022	12	0.004%	0.0005
4000462002	126165	804	3/17/2022	3/29/2022	12	0.000%	0.0000
4000461964	30580	5,216	3/17/2022	3/29/2022	12	0.001%	0.0002
4000462046	27068	6,612	3/18/2022	3/30/2022	12	0.002%	0.0002
4000462055	134272	70,986	3/18/2022	3/30/2022	12	0.019%	0.0022
4000462029	144519	44,600	3/18/2022	3/30/2022	12	0.012%	0.0014
4000462146	117183	2,024	3/23/2022	4/4/2022	12	0.001%	0.0001
4000462151	141583	471	3/23/2022	4/4/2022	12	0.000%	0.0000
4000462225	8392	9,896	3/25/2022	4/6/2022	12	0.003%	0.0003
4000462233	30475	63,511	3/25/2022	4/6/2022	12	0.017%	0.0020

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462239	117331	9,850	3/25/2022	4/6/2022	12	0.003%	0.0003
4000462202	15871	1,873	3/25/2022	4/6/2022	12	0.000%	0.0001
4000462222	144270	187	3/25/2022	4/6/2022	12	0.000%	0.0000
4000462224	208467	12,771	3/25/2022	4/6/2022	12	0.003%	0.0004
4000462380	11372	471	3/30/2022	4/11/2022	12	0.000%	0.0000
4000462390	27482	2,880	3/30/2022	4/11/2022	12	0.001%	0.0001
4000462405	134272	13,510	3/30/2022	4/11/2022	12	0.004%	0.0004
4000462345	126633	1,015	3/30/2022	4/11/2022	12	0.000%	0.0000
4000462352	134733	1,250	3/30/2022	4/11/2022	12	0.000%	0.0000
4000462374	144995	2,500	3/30/2022	4/11/2022	12	0.001%	0.0001
4000462414	116384	8	3/31/2022	4/12/2022	12	0.000%	0.0000
4000462520	10630	2,480	4/1/2022	4/13/2022	12	0.001%	0.0001
4000462526	24383	2,145	4/1/2022	4/13/2022	12	0.001%	0.0001
4000462528	25379	324	4/1/2022	4/13/2022	12	0.000%	0.0000
4000462531	26363	610	4/1/2022	4/13/2022	12	0.000%	0.0000
4000462483	105024	143	4/1/2022	4/13/2022	12	0.000%	0.0000
4000462490	118856	276	4/1/2022	4/13/2022	12	0.000%	0.0000
4000462508	143949	25,000	4/1/2022	4/13/2022	12	0.007%	0.0008
4000462472	117781	750	4/1/2022	4/13/2022	12	0.000%	0.0000
4000462635	23681	3,714	4/6/2022	4/18/2022	12	0.001%	0.0001
4000462675	11372	1,078	4/7/2022	4/19/2022	12	0.000%	0.0000
4000462687	126165	16,992	4/7/2022	4/19/2022	12	0.004%	0.0005
4000462672	145036	10,800	4/7/2022	4/19/2022	12	0.003%	0.0003
4000462730	27013	4,579	4/8/2022	4/20/2022	12	0.001%	0.0001
4000462731	27493	630	4/8/2022	4/20/2022	12	0.000%	0.0000
4000462694	104496	38	4/8/2022	4/20/2022	12	0.000%	0.0000
4000462696	105195	7,717	4/8/2022	4/20/2022	12	0.002%	0.0002
4000462704	135488	1,434	4/8/2022	4/20/2022	12	0.000%	0.0000
4000462718	144519	33,150	4/8/2022	4/20/2022	12	0.009%	0.0010
4000462851	9891	27,225	4/13/2022	4/25/2022	12	0.007%	0.0009
4000462853	25173	1,760	4/13/2022	4/25/2022	12	0.000%	0.0001
4000462857	33770	80,483	4/13/2022	4/25/2022	12	0.021%	0.0025
4000462805	104872	43	4/13/2022	4/25/2022	12	0.000%	0.0000
4000462809	108294	7,000	4/13/2022	4/25/2022	12	0.002%	0.0002
4000462827	131557	1,500	4/13/2022	4/25/2022	12	0.000%	0.0000
4000462837	142942	4,274	4/13/2022	4/25/2022	12	0.001%	0.0001
4000462841	144270	522	4/13/2022	4/25/2022	12	0.000%	0.0000
4000462850	145057	1,000	4/13/2022	4/25/2022	12	0.000%	0.0000
4000462899	18267	12,435	4/14/2022	4/26/2022	12	0.003%	0.0004
4000462903	25437	1,000	4/14/2022	4/26/2022	12	0.000%	0.0000
4000462909	26604	4,350	4/14/2022	4/26/2022	12	0.001%	0.0001
4000462931	126165	2,526	4/14/2022	4/26/2022	12	0.001%	0.0001
4000462932	130375	2,705	4/14/2022	4/26/2022	12	0.001%	0.0001
4000462869	30580	3,726	4/14/2022	4/26/2022	12	0.001%	0.0001
4000462871	105195	20,066	4/14/2022	4/26/2022	12	0.005%	0.0006
4000462885	143941	2,491	4/14/2022	4/26/2022	12	0.001%	0.0001
4000463015	9121	1,500	4/20/2022	5/2/2022	12	0.000%	0.0000
4000463016	11054	9,296	4/20/2022	5/2/2022	12	0.002%	0.0003
4000463022	27677	14,884	4/20/2022	5/2/2022	12	0.004%	0.0005
4000463004	142942	2,079	4/20/2022	5/2/2022	12	0.001%	0.0001
4000463048	8392	10,683	4/21/2022	5/3/2022	12	0.003%	0.0003
4000463070	27389	920	4/21/2022	5/3/2022	12	0.000%	0.0000
4000463116	17342	36,045	4/22/2022	5/4/2022	12	0.010%	0.0011

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463121	27068	10,716	4/22/2022	5/4/2022	12	0.003%	0.0003
4000463123	28084	475	4/22/2022	5/4/2022	12	0.000%	0.0000
4000463127	30475	43,075	4/22/2022	5/4/2022	12	0.011%	0.0014
4000463128	30475	47,043	4/22/2022	5/4/2022	12	0.012%	0.0015
4000463129	30475	49,513	4/22/2022	5/4/2022	12	0.013%	0.0016
4000463130	30475	74,956	4/22/2022	5/4/2022	12	0.020%	0.0024
4000463131	30475	79,673	4/22/2022	5/4/2022	12	0.021%	0.0025
4000463140	124943	950	4/22/2022	5/4/2022	12	0.000%	0.0000
4000463080	15871	2,909	4/22/2022	5/4/2022	12	0.001%	0.0001
4000463082	34888	6,132	4/22/2022	5/4/2022	12	0.002%	0.0002
4000463091	123377	5,950	4/22/2022	5/4/2022	12	0.002%	0.0002
4000463229	9673	3,475	4/27/2022	5/9/2022	12	0.001%	0.0001
4000463243	26643	1,964	4/27/2022	5/9/2022	12	0.001%	0.0001
4000463216	111664	17,500	4/27/2022	5/9/2022	12	0.005%	0.0006
4000463220	135441	2,500	4/27/2022	5/9/2022	12	0.001%	0.0001
4000463227	144270	7,780	4/27/2022	5/9/2022	12	0.002%	0.0002
4000463207	126568	2,840	4/27/2022	5/9/2022	12	0.001%	0.0001
4000463284	144084	1,070	4/28/2022	5/10/2022	12	0.000%	0.0000
4000463259	114424	748	4/28/2022	5/10/2022	12	0.000%	0.0000
4000463378	26361	28,631	4/29/2022	5/11/2022	12	0.008%	0.0009
4000463381	26659	34,596	4/29/2022	5/11/2022	12	0.009%	0.0011
4000463382	27013	22,488	4/29/2022	5/11/2022	12	0.006%	0.0007
4000463383	27962	1,938	4/29/2022	5/11/2022	12	0.001%	0.0001
4000463388	30257	2,718	4/29/2022	5/11/2022	12	0.001%	0.0001
4000463389	30475	39,208	4/29/2022	5/11/2022	12	0.010%	0.0012
4000463390	30475	44,212	4/29/2022	5/11/2022	12	0.012%	0.0014
4000463392	30475	36,794	4/29/2022	5/11/2022	12	0.010%	0.0012
4000463394	32538	237	4/29/2022	5/11/2022	12	0.000%	0.0000
4000463403	138068	716	4/29/2022	5/11/2022	12	0.000%	0.0000
4000463326	15871	198	4/29/2022	5/11/2022	12	0.000%	0.0000
4000463327	22798	106,886	4/29/2022	5/11/2022	12	0.028%	0.0034
4000463328	22798	79,920	4/29/2022	5/11/2022	12	0.021%	0.0025
4000463334	112103	153,910	4/29/2022	5/11/2022	12	0.041%	0.0049
4000463336	113967	221	4/29/2022	5/11/2022	12	0.000%	0.0000
4000463338	130634	3,510	4/29/2022	5/11/2022	12	0.001%	0.0001
4000463347	142642	374	4/29/2022	5/11/2022	12	0.000%	0.0000
4000463349	142926	9,761	4/29/2022	5/11/2022	12	0.003%	0.0003
4000463364	144982	23,032	4/29/2022	5/11/2022	12	0.006%	0.0007
4000463537	26674	840	5/4/2022	5/16/2022	12	0.000%	0.0000
4000463540	33770	22,431	5/4/2022	5/16/2022	12	0.006%	0.0007
4000463553	103471	610	5/5/2022	5/17/2022	12	0.000%	0.0000
4000463568	144773	625	5/5/2022	5/17/2022	12	0.000%	0.0000
4000463613	26643	2,533	5/6/2022	5/18/2022	12	0.001%	0.0001
4000463615	30475	37,779	5/6/2022	5/18/2022	12	0.010%	0.0012
4000463616	30475	41,158	5/6/2022	5/18/2022	12	0.011%	0.0013
4000463617	30475	30,281	5/6/2022	5/18/2022	12	0.008%	0.0010
4000463618	30475	32,544	5/6/2022	5/18/2022	12	0.009%	0.0010
4000463619	30475	35,540	5/6/2022	5/18/2022	12	0.009%	0.0011
4000463598	143463	201,180	5/6/2022	5/18/2022	12	0.053%	0.0064
4000463600	144262	4,351	5/6/2022	5/18/2022	12	0.001%	0.0001
4000463605	144803	42,712	5/6/2022	5/18/2022	12	0.011%	0.0014
4000463710	8998	32,568	5/11/2022	5/23/2022	12	0.009%	0.0010
4000463712	11372	471	5/11/2022	5/23/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463715	24385	729	5/11/2022	5/23/2022	12	0.000%	0.0000
4000463697	126928	39,738	5/11/2022	5/23/2022	12	0.010%	0.0013
4000463751	34341	9,900	5/12/2022	5/24/2022	12	0.003%	0.0003
4000463743	121825	34,283	5/12/2022	5/24/2022	12	0.009%	0.0011
4000463744	138494	6,160	5/12/2022	5/24/2022	12	0.002%	0.0002
4000463745	142942	1,472	5/12/2022	5/24/2022	12	0.000%	0.0000
4000463747	144519	29,427	5/12/2022	5/24/2022	12	0.008%	0.0009
4000463798	25808	3,360	5/13/2022	5/25/2022	12	0.001%	0.0001
4000463801	26639	540	5/13/2022	5/25/2022	12	0.000%	0.0000
4000463813	30773	5,173	5/13/2022	5/25/2022	12	0.001%	0.0002
4000463763	34888	1,920	5/13/2022	5/25/2022	12	0.001%	0.0001
4000463765	104872	150	5/13/2022	5/25/2022	12	0.000%	0.0000
4000463772	124628	8,681	5/13/2022	5/25/2022	12	0.002%	0.0003
4000463775	126928	54	5/13/2022	5/25/2022	12	0.000%	0.0000
4000463780	141583	1,142	5/13/2022	5/25/2022	12	0.000%	0.0000
4000463787	144791	5,200	5/13/2022	5/25/2022	12	0.001%	0.0002
4000464001	24251	12,000	5/19/2022	5/31/2022	12	0.003%	0.0004
4000464002	24251	12,420	5/19/2022	5/31/2022	12	0.003%	0.0004
4000464006	27389	690	5/19/2022	5/31/2022	12	0.000%	0.0000
4000463975	4208	3,600	5/19/2022	5/31/2022	12	0.001%	0.0001
4000463976	4502	3,759	5/19/2022	5/31/2022	12	0.001%	0.0001
4000463977	6031	2,610	5/19/2022	5/31/2022	12	0.001%	0.0001
4000463983	104872	30	5/19/2022	5/31/2022	12	0.000%	0.0000
4000463989	142926	56,782	5/19/2022	5/31/2022	12	0.015%	0.0018
4000463996	144955	453	5/19/2022	5/31/2022	12	0.000%	0.0000
4000464046	18267	4,843	5/20/2022	6/1/2022	12	0.001%	0.0002
4000464048	25083	12,455	5/20/2022	6/1/2022	12	0.003%	0.0004
4000464049	26659	6,047	5/20/2022	6/1/2022	12	0.002%	0.0002
4000464053	30475	48,620	5/20/2022	6/1/2022	12	0.013%	0.0015
4000464054	30475	33,742	5/20/2022	6/1/2022	12	0.009%	0.0011
4000464055	30475	37,507	5/20/2022	6/1/2022	12	0.010%	0.0012
4000464056	30475	39,961	5/20/2022	6/1/2022	12	0.011%	0.0013
4000464057	30475	43,210	5/20/2022	6/1/2022	12	0.011%	0.0014
4000464058	33770	70,407	5/20/2022	6/1/2022	12	0.019%	0.0022
4000464060	34341	7,700	5/20/2022	6/1/2022	12	0.002%	0.0002
4000464062	105195	7,874	5/20/2022	6/1/2022	12	0.002%	0.0002
4000464063	117331	15,900	5/20/2022	6/1/2022	12	0.004%	0.0005
4000464014	4502	8,392	5/20/2022	6/1/2022	12	0.002%	0.0003
4000464018	34888	726	5/20/2022	6/1/2022	12	0.000%	0.0000
4000464019	101853	3,167	5/20/2022	6/1/2022	12	0.001%	0.0001
4000464022	105195	13,493	5/20/2022	6/1/2022	12	0.004%	0.0004
4000464028	134862	1,012,842	5/20/2022	6/1/2022	12	0.267%	0.0321
4000464030	141101	156,060	5/20/2022	6/1/2022	12	0.041%	0.0049
4000464033	142926	8,010	5/20/2022	6/1/2022	12	0.002%	0.0003
4000464038	143941	2,476	5/20/2022	6/1/2022	12	0.001%	0.0001
4000464043	144982	2,599	5/20/2022	6/1/2022	12	0.001%	0.0001
4000464044	145081	7,000	5/20/2022	6/1/2022	12	0.002%	0.0002
4000464158	8392	9,429	5/25/2022	6/6/2022	12	0.002%	0.0003
4000464139	101853	6,930	5/25/2022	6/6/2022	12	0.002%	0.0002
4000464142	113563	33	5/25/2022	6/6/2022	12	0.000%	0.0000
4000464227	30252	11,200	5/26/2022	6/7/2022	12	0.003%	0.0004
4000464235	126165	2,870	5/26/2022	6/7/2022	12	0.001%	0.0001
4000464186	118374	3,640	5/26/2022	6/7/2022	12	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464197	143573	1,619,456	5/26/2022	6/7/2022	12	0.427%	0.0513
4000464207	145114	4,667	5/26/2022	6/7/2022	12	0.001%	0.0001
4000464297	30257	7,585	5/27/2022	6/8/2022	12	0.002%	0.0002
4000464298	30475	31,302	5/27/2022	6/8/2022	12	0.008%	0.0010
4000464299	30475	45,591	5/27/2022	6/8/2022	12	0.012%	0.0014
4000464300	33770	8,388	5/27/2022	6/8/2022	12	0.002%	0.0003
4000464239	4502	6,212	5/27/2022	6/8/2022	12	0.002%	0.0002
4000464240	6396	5,950	5/27/2022	6/8/2022	12	0.002%	0.0002
4000464241	9145	18,550	5/27/2022	6/8/2022	12	0.005%	0.0006
4000464242	15871	6,594	5/27/2022	6/8/2022	12	0.002%	0.0002
4000464244	21678	267,611	5/27/2022	6/8/2022	12	0.071%	0.0085
4000464247	26471	20,187	5/27/2022	6/8/2022	12	0.005%	0.0006
4000464252	101853	172,722	5/27/2022	6/8/2022	12	0.046%	0.0055
4000464259	118487	120,614	5/27/2022	6/8/2022	12	0.032%	0.0038
4000464266	126928	147	5/27/2022	6/8/2022	12	0.000%	0.0000
4000464275	142926	149,738	5/27/2022	6/8/2022	12	0.039%	0.0047
4000464287	144982	80,330	5/27/2022	6/8/2022	12	0.021%	0.0025
4000464395	13911	4,245	6/1/2022	6/13/2022	12	0.001%	0.0001
4000464396	23681	1,061	6/1/2022	6/13/2022	12	0.000%	0.0000
4000464373	13911	17,420	6/1/2022	6/13/2022	12	0.005%	0.0006
4000464471	11536	7,150	6/2/2022	6/14/2022	12	0.002%	0.0002
4000464477	26659	499	6/2/2022	6/14/2022	12	0.000%	0.0000
4000464484	106699	10,827	6/2/2022	6/14/2022	12	0.003%	0.0003
4000464485	117331	66,600	6/2/2022	6/14/2022	12	0.018%	0.0021
4000464426	116850	431	6/2/2022	6/14/2022	12	0.000%	0.0000
4000464430	128436	1,500	6/2/2022	6/14/2022	12	0.000%	0.0000
4000464431	131647	2,338	6/2/2022	6/14/2022	12	0.001%	0.0001
4000464437	141021	2,700	6/2/2022	6/14/2022	12	0.001%	0.0001
4000464445	142607	2,500	6/2/2022	6/14/2022	12	0.001%	0.0001
4000464460	144510	2,000	6/2/2022	6/14/2022	12	0.001%	0.0001
4000464462	144573	4,000	6/2/2022	6/14/2022	12	0.001%	0.0001
4000464463	144773	625	6/2/2022	6/14/2022	12	0.000%	0.0000
4000464469	145034	11,306	6/2/2022	6/14/2022	12	0.003%	0.0004
4000464532	30475	114,858	6/3/2022	6/15/2022	12	0.030%	0.0036
4000464533	30475	75,810	6/3/2022	6/15/2022	12	0.020%	0.0024
4000464534	30475	81,718	6/3/2022	6/15/2022	12	0.022%	0.0026
4000464535	30475	97,762	6/3/2022	6/15/2022	12	0.026%	0.0031
4000464543	134272	3,810	6/3/2022	6/15/2022	12	0.001%	0.0001
4000464492	6396	8,921	6/3/2022	6/15/2022	12	0.002%	0.0003
4000464505	139288	1,038	6/3/2022	6/15/2022	12	0.000%	0.0000
4000464522	144982	8,774	6/3/2022	6/15/2022	12	0.002%	0.0003
4000464526	145067	2,200	6/3/2022	6/15/2022	12	0.001%	0.0001
4000464676	34658	30,000	6/9/2022	6/21/2022	12	0.008%	0.0009
4000464644	4502	10,779	6/9/2022	6/21/2022	12	0.003%	0.0003
4000464645	6031	249	6/9/2022	6/21/2022	12	0.000%	0.0000
4000464646	15871	1,616	6/9/2022	6/21/2022	12	0.000%	0.0001
4000464647	32842	7,486	6/9/2022	6/21/2022	12	0.002%	0.0002
4000464648	34888	1,380	6/9/2022	6/21/2022	12	0.000%	0.0000
4000464659	144519	11,150	6/9/2022	6/21/2022	12	0.003%	0.0004
4000464723	24383	890	6/10/2022	6/22/2022	12	0.000%	0.0000
4000464724	25659	13,035	6/10/2022	6/22/2022	12	0.003%	0.0004
4000464725	25808	480	6/10/2022	6/22/2022	12	0.000%	0.0000
4000464726	26213	736	6/10/2022	6/22/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464738	117331	52,450	6/10/2022	6/22/2022	12	0.014%	0.0017
4000464739	117331	54,000	6/10/2022	6/22/2022	12	0.014%	0.0017
4000464682	4502	22,087	6/10/2022	6/22/2022	12	0.006%	0.0007
4000464685	15871	100	6/10/2022	6/22/2022	12	0.000%	0.0000
4000464715	144955	10,744	6/10/2022	6/22/2022	12	0.003%	0.0003
4000464843	9673	525	6/15/2022	6/27/2022	12	0.000%	0.0000
4000464844	11426	677	6/15/2022	6/27/2022	12	0.000%	0.0000
4000464858	32356	766	6/15/2022	6/27/2022	12	0.000%	0.0000
4000464859	33773	4,350	6/15/2022	6/27/2022	12	0.001%	0.0001
4000464833	129859	15,180	6/15/2022	6/27/2022	12	0.004%	0.0005
4000464836	142942	1,493	6/15/2022	6/27/2022	12	0.000%	0.0000
4000464837	143153	40,000	6/15/2022	6/27/2022	12	0.011%	0.0013
4000464889	23681	1,910	6/16/2022	6/28/2022	12	0.001%	0.0001
4000464877	141826	18,620	6/16/2022	6/28/2022	12	0.005%	0.0006
4000464936	9121	1,000	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464939	11305	674	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464945	25131	10,640	6/17/2022	6/29/2022	12	0.003%	0.0003
4000464947	26356	1,234	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464953	27994	440	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464954	28084	10,213	6/17/2022	6/29/2022	12	0.003%	0.0003
4000464956	29938	3,425	6/17/2022	6/29/2022	12	0.001%	0.0001
4000464957	30475	59,006	6/17/2022	6/29/2022	12	0.016%	0.0019
4000464958	30475	41,135	6/17/2022	6/29/2022	12	0.011%	0.0013
4000464959	30475	42,419	6/17/2022	6/29/2022	12	0.011%	0.0013
4000464960	30475	44,267	6/17/2022	6/29/2022	12	0.012%	0.0014
4000464961	30475	46,742	6/17/2022	6/29/2022	12	0.012%	0.0015
4000464962	30475	50,467	6/17/2022	6/29/2022	12	0.013%	0.0016
4000464963	30475	52,335	6/17/2022	6/29/2022	12	0.014%	0.0017
4000464901	15871	8,344	6/17/2022	6/29/2022	12	0.002%	0.0003
4000464903	34888	22	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464904	103392	198	6/17/2022	6/29/2022	12	0.000%	0.0000
4000464924	143072	2,833	6/17/2022	6/29/2022	12	0.001%	0.0001
4000464933	144982	60,032	6/17/2022	6/29/2022	12	0.016%	0.0019
4000465107	130375	26,867	6/23/2022	7/5/2022	12	0.007%	0.0009
4000465062	13911	19,910	6/23/2022	7/5/2022	12	0.005%	0.0006
4000465083	144687	219	6/23/2022	7/5/2022	12	0.000%	0.0000
4000465147	13534	16,672	6/24/2022	7/6/2022	12	0.004%	0.0005
4000465155	25938	22,670	6/24/2022	7/6/2022	12	0.006%	0.0007
4000465156	26297	294	6/24/2022	7/6/2022	12	0.000%	0.0000
4000465165	30475	37,677	6/24/2022	7/6/2022	12	0.010%	0.0012
4000465166	32538	769	6/24/2022	7/6/2022	12	0.000%	0.0000
4000465172	117331	39,800	6/24/2022	7/6/2022	12	0.010%	0.0013
4000465111	4502	19,986	6/24/2022	7/6/2022	12	0.005%	0.0006
4000465118	101853	55,139	6/24/2022	7/6/2022	12	0.015%	0.0017
4000465134	143340	59,545	6/24/2022	7/6/2022	12	0.016%	0.0019
4000465135	143426	109,625	6/24/2022	7/6/2022	12	0.029%	0.0035
4000465278	119251	546,880	6/29/2022	7/11/2022	12	0.144%	0.0173
4000465338	143520	2,235	6/30/2022	7/12/2022	12	0.001%	0.0001
4000465435	25131	808	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465436	25659	23,278	7/1/2022	7/13/2022	12	0.006%	0.0007
4000465437	25808	720	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465439	26016	796	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465440	26213	1,012	7/1/2022	7/13/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465445	26490	11,593	7/1/2022	7/13/2022	12	0.003%	0.0004
4000465451	27962	456	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465454	29938	13,700	7/1/2022	7/13/2022	12	0.004%	0.0004
4000465465	106699	4,500	7/1/2022	7/13/2022	12	0.001%	0.0001
4000465383	15871	4,408	7/1/2022	7/13/2022	12	0.001%	0.0001
4000465386	25623	655	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465390	34888	143	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465391	35151	2,250	7/1/2022	7/13/2022	12	0.001%	0.0001
4000465394	104154	264	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465398	106840	119	7/1/2022	7/13/2022	12	0.000%	0.0000
4000465401	113967	4,990	7/1/2022	7/13/2022	12	0.001%	0.0002
4000465407	134862	126,274	7/1/2022	7/13/2022	12	0.033%	0.0040
4000465414	143072	8,152	7/1/2022	7/13/2022	12	0.002%	0.0003
4000465418	143577	6,551	7/1/2022	7/13/2022	12	0.002%	0.0002
4000465422	144878	2,112	7/1/2022	7/13/2022	12	0.001%	0.0001
4000465425	145168	124,732	7/1/2022	7/13/2022	12	0.033%	0.0039
4000465520	11536	820	7/6/2022	7/18/2022	12	0.000%	0.0000
4000465557	30475	9,788	7/7/2022	7/19/2022	12	0.003%	0.0003
4000465595	8392	10,713	7/8/2022	7/20/2022	12	0.003%	0.0003
4000465604	25599	1,708	7/8/2022	7/20/2022	12	0.000%	0.0001
4000465605	25809	424	7/8/2022	7/20/2022	12	0.000%	0.0000
4000465609	26363	6,241	7/8/2022	7/20/2022	12	0.002%	0.0002
4000465613	26642	5,930	7/8/2022	7/20/2022	12	0.002%	0.0002
4000465616	27013	6,166	7/8/2022	7/20/2022	12	0.002%	0.0002
4000465617	27068	5,130	7/8/2022	7/20/2022	12	0.001%	0.0002
4000465625	34348	3,045	7/8/2022	7/20/2022	12	0.001%	0.0001
4000465627	109948	5,529	7/8/2022	7/20/2022	12	0.001%	0.0002
4000465629	130375	1,048	7/8/2022	7/20/2022	12	0.000%	0.0000
4000465568	26471	72,773	7/8/2022	7/20/2022	12	0.019%	0.0023
4000465591	145056	595,104	7/8/2022	7/20/2022	12	0.157%	0.0188
4000465764	27994	5,060	7/13/2022	7/25/2022	12	0.001%	0.0002
4000465742	104872	783	7/13/2022	7/25/2022	12	0.000%	0.0000
4000465750	142170	2,500	7/13/2022	7/25/2022	12	0.001%	0.0001
4000465797	26297	604	7/14/2022	7/26/2022	12	0.000%	0.0000
4000465812	125016	3,540	7/14/2022	7/26/2022	12	0.001%	0.0001
4000465775	9673	5,350	7/14/2022	7/26/2022	12	0.001%	0.0002
4000465848	26016	882	7/15/2022	7/27/2022	12	0.000%	0.0000
4000465859	33203	3,795	7/15/2022	7/27/2022	12	0.001%	0.0001
4000465864	34658	2,500	7/15/2022	7/27/2022	12	0.001%	0.0001
4000465826	141826	19,953	7/15/2022	7/27/2022	12	0.005%	0.0006
4000465828	142926	11,510	7/15/2022	7/27/2022	12	0.003%	0.0004
4000465829	142942	25,758	7/15/2022	7/27/2022	12	0.007%	0.0008
4000465967	24211	16,742	7/20/2022	8/1/2022	12	0.004%	0.0005
4000465944	104872	154	7/20/2022	8/1/2022	12	0.000%	0.0000
4000465941	106652	3,861	7/20/2022	8/1/2022	12	0.001%	0.0001
4000466018	33770	58,380	7/21/2022	8/2/2022	12	0.015%	0.0018
4000466056	11305	8,283	7/22/2022	8/3/2022	12	0.002%	0.0003
4000466058	17342	16,740	7/22/2022	8/3/2022	12	0.004%	0.0005
4000466061	24825	1,316	7/22/2022	8/3/2022	12	0.000%	0.0000
4000466067	26604	3,405	7/22/2022	8/3/2022	12	0.001%	0.0001
4000466068	26639	27,270	7/22/2022	8/3/2022	12	0.007%	0.0009
4000466024	15871	1,400	7/22/2022	8/3/2022	12	0.000%	0.0000
4000466026	34888	20	7/22/2022	8/3/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466034	134862	3,403,513	7/22/2022	8/3/2022	12	0.898%	0.1077
4000466185	11536	5,320	7/27/2022	8/8/2022	12	0.001%	0.0002
4000466173	135057	15	7/27/2022	8/8/2022	12	0.000%	0.0000
4000466227	9673	2,750	7/28/2022	8/9/2022	12	0.001%	0.0001
4000466229	18267	4,578	7/28/2022	8/9/2022	12	0.001%	0.0001
4000466242	27994	440	7/28/2022	8/9/2022	12	0.000%	0.0000
4000466244	32875	5,200	7/28/2022	8/9/2022	12	0.001%	0.0002
4000466250	105195	4,009	7/28/2022	8/9/2022	12	0.001%	0.0001
4000466251	125016	762	7/28/2022	8/9/2022	12	0.000%	0.0000
4000466212	105195	2,377	7/28/2022	8/9/2022	12	0.001%	0.0001
4000466215	123915	885	7/28/2022	8/9/2022	12	0.000%	0.0000
4000466217	126928	27	7/28/2022	8/9/2022	12	0.000%	0.0000
4000466294	18518	5,400	7/29/2022	8/10/2022	12	0.001%	0.0002
4000466297	25173	3,520	7/29/2022	8/10/2022	12	0.001%	0.0001
4000466300	26297	9,908	7/29/2022	8/10/2022	12	0.003%	0.0003
4000466304	26453	3,200	7/29/2022	8/10/2022	12	0.001%	0.0001
4000466313	27704	1,700	7/29/2022	8/10/2022	12	0.000%	0.0001
4000466328	33203	16,675	7/29/2022	8/10/2022	12	0.004%	0.0005
4000466336	34658	2,500	7/29/2022	8/10/2022	12	0.001%	0.0001
4000466337	34937	12,000	7/29/2022	8/10/2022	12	0.003%	0.0004
4000466254	4765	19,211	7/29/2022	8/10/2022	12	0.005%	0.0006
4000466263	26996	15,128	7/29/2022	8/10/2022	12	0.004%	0.0005
4000466264	27094	134,110	7/29/2022	8/10/2022	12	0.035%	0.0042
4000466267	34888	30	7/29/2022	8/10/2022	12	0.000%	0.0000
4000466271	113967	10,917	7/29/2022	8/10/2022	12	0.003%	0.0003
4000466273	130634	60,744	7/29/2022	8/10/2022	12	0.016%	0.0019
4000466278	139713	38,595	7/29/2022	8/10/2022	12	0.010%	0.0012
4000466290	144982	33,228	7/29/2022	8/10/2022	12	0.009%	0.0011
4000466469	26604	1,775	8/3/2022	8/15/2022	12	0.000%	0.0001
4000466470	26679	17,375	8/3/2022	8/15/2022	12	0.005%	0.0005
4000466447	104872	247	8/3/2022	8/15/2022	12	0.000%	0.0000
4000466480	32971	2,507	8/3/2022	8/15/2022	12	0.001%	0.0001
4000466484	33102	41,412	8/3/2022	8/15/2022	12	0.011%	0.0013
4000466485	33106	5,923	8/3/2022	8/15/2022	12	0.002%	0.0002
4000466487	33135	21,871	8/3/2022	8/15/2022	12	0.006%	0.0007
4000466525	117331	29,125	8/4/2022	8/16/2022	12	0.008%	0.0009
4000466491	17667	2,985	8/4/2022	8/16/2022	12	0.001%	0.0001
4000466493	27094	7,429	8/4/2022	8/16/2022	12	0.002%	0.0002
4000466495	106674	8,058	8/4/2022	8/16/2022	12	0.002%	0.0003
4000466496	108149	106	8/4/2022	8/16/2022	12	0.000%	0.0000
4000466499	116384	118	8/4/2022	8/16/2022	12	0.000%	0.0000
4000466500	118807	689	8/4/2022	8/16/2022	12	0.000%	0.0000
4000466567	25987	900	8/5/2022	8/17/2022	12	0.000%	0.0000
4000466568	26604	28,845	8/5/2022	8/17/2022	12	0.008%	0.0009
4000466570	27994	5,610	8/5/2022	8/17/2022	12	0.001%	0.0002
4000466572	30475	92,414	8/5/2022	8/17/2022	12	0.024%	0.0029
4000466573	30475	82,930	8/5/2022	8/17/2022	12	0.022%	0.0026
4000466542	142619	6,200	8/5/2022	8/17/2022	12	0.002%	0.0002
4000466546	142942	14,444	8/5/2022	8/17/2022	12	0.004%	0.0005
4000466558	144492	17,042	8/5/2022	8/17/2022	12	0.004%	0.0005
4000466681	29919	17,800	8/10/2022	8/22/2022	12	0.005%	0.0006
4000466663	134862	907,463	8/10/2022	8/22/2022	12	0.239%	0.0287
4000466674	144530	9,875	8/10/2022	8/22/2022	12	0.003%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466717	33137	14,071	8/10/2022	8/22/2022	12	0.004%	0.0004
4000466721	33145	3,374	8/10/2022	8/22/2022	12	0.001%	0.0001
4000466752	14949	1,698	8/11/2022	8/23/2022	12	0.000%	0.0001
4000466753	18275	18,407	8/11/2022	8/23/2022	12	0.005%	0.0006
4000466759	27094	9,832	8/11/2022	8/23/2022	12	0.003%	0.0003
4000466768	117331	6,250	8/11/2022	8/23/2022	12	0.002%	0.0002
4000466724	4502	4,484	8/11/2022	8/23/2022	12	0.001%	0.0001
4000466727	27094	4,415	8/11/2022	8/23/2022	12	0.001%	0.0001
4000466732	105195	1,510	8/11/2022	8/23/2022	12	0.000%	0.0000
4000466738	142942	704	8/11/2022	8/23/2022	12	0.000%	0.0000
4000466741	143659	8,595	8/11/2022	8/23/2022	12	0.002%	0.0003
4000466743	144567	2,000	8/11/2022	8/23/2022	12	0.001%	0.0001
4000466745	144816	471	8/11/2022	8/23/2022	12	0.000%	0.0000
4000466807	27013	3,313	8/12/2022	8/24/2022	12	0.001%	0.0001
4000466771	15871	1,186	8/12/2022	8/24/2022	12	0.000%	0.0000
4000466927	26453	1,980	8/17/2022	8/29/2022	12	0.001%	0.0001
4000466931	26644	6,345	8/17/2022	8/29/2022	12	0.002%	0.0002
4000466940	126165	5,913	8/17/2022	8/29/2022	12	0.002%	0.0002
4000466899	6031	110	8/17/2022	8/29/2022	12	0.000%	0.0000
4000466905	107047	20,944	8/17/2022	8/29/2022	12	0.006%	0.0007
4000466914	142942	6,127	8/17/2022	8/29/2022	12	0.002%	0.0002
4000466941	9145	9,550	8/18/2022	8/30/2022	12	0.003%	0.0003
4000466947	105195	1,893	8/18/2022	8/30/2022	12	0.000%	0.0001
4000467014	17342	4,725	8/19/2022	8/31/2022	12	0.001%	0.0001
4000467019	26639	21,600	8/19/2022	8/31/2022	12	0.006%	0.0007
4000467025	30475	7,233	8/19/2022	8/31/2022	12	0.002%	0.0002
4000467029	34658	2,500	8/19/2022	8/31/2022	12	0.001%	0.0001
4000466974	15871	5,637	8/19/2022	8/31/2022	12	0.001%	0.0002
4000466997	142942	23,928	8/19/2022	8/31/2022	12	0.006%	0.0008
4000467001	143477	4,297	8/19/2022	8/31/2022	12	0.001%	0.0001
4000467008	144982	22,421	8/19/2022	8/31/2022	12	0.006%	0.0007
4000467180	24211	10,555	8/25/2022	9/6/2022	12	0.003%	0.0003
4000467181	24259	3,212	8/25/2022	9/6/2022	12	0.001%	0.0001
4000467189	30475	93,444	8/25/2022	9/6/2022	12	0.025%	0.0030
4000467190	30475	84,913	8/25/2022	9/6/2022	12	0.022%	0.0027
4000467156	103603	10,349	8/25/2022	9/6/2022	12	0.003%	0.0003
4000467157	104872	77	8/25/2022	9/6/2022	12	0.000%	0.0000
4000467160	108289	271	8/25/2022	9/6/2022	12	0.000%	0.0000
4000467170	142926	114,638	8/25/2022	9/6/2022	12	0.030%	0.0036
4000467233	18267	1,476	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467240	27981	3,380	8/26/2022	9/7/2022	12	0.001%	0.0001
4000467245	30257	4,097	8/26/2022	9/7/2022	12	0.001%	0.0001
4000467248	34341	24,425	8/26/2022	9/7/2022	12	0.006%	0.0008
4000467250	34658	1,500	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467199	7214	532,316	8/26/2022	9/7/2022	12	0.140%	0.0168
4000467202	27094	41,281	8/26/2022	9/7/2022	12	0.011%	0.0013
4000467203	27466	2,851	8/26/2022	9/7/2022	12	0.001%	0.0001
4000467207	105195	17,633	8/26/2022	9/7/2022	12	0.005%	0.0006
4000467208	110291	9,812	8/26/2022	9/7/2022	12	0.003%	0.0003
4000467209	112103	104,524	8/26/2022	9/7/2022	12	0.028%	0.0033
4000467213	129757	49	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467214	134862	236,180	8/26/2022	9/7/2022	12	0.062%	0.0075
4000467222	143312	50,792	8/26/2022	9/7/2022	12	0.013%	0.0016

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467224	143340	63,308	8/26/2022	9/7/2022	12	0.017%	0.0020
4000467225	143920	35	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467226	144816	10,714	8/26/2022	9/7/2022	12	0.003%	0.0003
4000467227	145093	505	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467228	145193	250	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467230	145292	50,000	8/26/2022	9/7/2022	12	0.013%	0.0016
4000467252	32955	12,597	8/26/2022	9/7/2022	12	0.003%	0.0004
4000467253	32969	143,167	8/26/2022	9/7/2022	12	0.038%	0.0045
4000467261	33116	673	8/26/2022	9/7/2022	12	0.000%	0.0000
4000467369	11260	18,088	8/31/2022	9/12/2022	12	0.005%	0.0006
4000467370	11577	6,038	8/31/2022	9/12/2022	12	0.002%	0.0002
4000467382	27962	7,352	8/31/2022	9/12/2022	12	0.002%	0.0002
4000467384	28737	12,255	8/31/2022	9/12/2022	12	0.003%	0.0004
4000467387	33238	1,050	8/31/2022	9/12/2022	12	0.000%	0.0000
4000467351	125827	500	8/31/2022	9/12/2022	12	0.000%	0.0000
4000467430	26363	6,932	9/1/2022	9/13/2022	12	0.002%	0.0002
4000467433	26604	1,390	9/1/2022	9/13/2022	12	0.000%	0.0000
4000467438	27994	1,925	9/1/2022	9/13/2022	12	0.001%	0.0001
4000467440	30475	300	9/1/2022	9/13/2022	12	0.000%	0.0000
4000467445	106699	3,271	9/1/2022	9/13/2022	12	0.001%	0.0001
4000467446	117331	22,300	9/1/2022	9/13/2022	12	0.006%	0.0007
4000467396	15871	1,014	9/1/2022	9/13/2022	12	0.000%	0.0000
4000467418	144519	4,600	9/1/2022	9/13/2022	12	0.001%	0.0001
4000467517	11305	3,978	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467519	26490	1,014	9/2/2022	9/14/2022	12	0.000%	0.0000
4000467521	26639	3,375	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467523	27013	756	9/2/2022	9/14/2022	12	0.000%	0.0000
4000467531	34341	7,095	9/2/2022	9/14/2022	12	0.002%	0.0002
4000467449	4627	9,072	9/2/2022	9/14/2022	12	0.002%	0.0003
4000467455	15871	7,725	9/2/2022	9/14/2022	12	0.002%	0.0002
4000467456	26958	5,904	9/2/2022	9/14/2022	12	0.002%	0.0002
4000467462	110291	5,014	9/2/2022	9/14/2022	12	0.001%	0.0002
4000467464	116850	431	9/2/2022	9/14/2022	12	0.000%	0.0000
4000467467	126715	10,500	9/2/2022	9/14/2022	12	0.003%	0.0003
4000467479	141831	11,880	9/2/2022	9/14/2022	12	0.003%	0.0004
4000467481	142162	11,000	9/2/2022	9/14/2022	12	0.003%	0.0003
4000467483	142787	10,258	9/2/2022	9/14/2022	12	0.003%	0.0003
4000467489	143270	4,500	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467490	143364	12,300	9/2/2022	9/14/2022	12	0.003%	0.0004
4000467493	143577	7,639	9/2/2022	9/14/2022	12	0.002%	0.0002
4000467499	144410	2,850	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467502	144573	4,000	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467507	144986	4,000	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467509	145034	11,345	9/2/2022	9/14/2022	12	0.003%	0.0004
4000467511	145193	4,210	9/2/2022	9/14/2022	12	0.001%	0.0001
4000467578	26363	1,474	9/7/2022	9/19/2022	12	0.000%	0.0000
4000467567	104872	22	9/7/2022	9/19/2022	12	0.000%	0.0000
4000467616	27994	14,630	9/8/2022	9/20/2022	12	0.004%	0.0005
4000467617	30475	15,513	9/8/2022	9/20/2022	12	0.004%	0.0005
4000467620	104725	980	9/8/2022	9/20/2022	12	0.000%	0.0000
4000467592	104872	783	9/8/2022	9/20/2022	12	0.000%	0.0000
4000467604	143659	48,865	9/8/2022	9/20/2022	12	0.013%	0.0015
4000467609	145222	736	9/8/2022	9/20/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467624	15871	20,924	9/9/2022	9/21/2022	12	0.006%	0.0007
4000467625	103471	40	9/9/2022	9/21/2022	12	0.000%	0.0000
4000467630	137757	35,562	9/9/2022	9/21/2022	12	0.009%	0.0011
4000467635	142942	928	9/9/2022	9/21/2022	12	0.000%	0.0000
4000467636	143072	48,630	9/9/2022	9/21/2022	12	0.013%	0.0015
4000467637	143111	5,000	9/9/2022	9/21/2022	12	0.001%	0.0002
4000467640	143573	1,260,455	9/9/2022	9/21/2022	12	0.332%	0.0399
4000467650	145193	8,260	9/9/2022	9/21/2022	12	0.002%	0.0003
4000467755	25599	796	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467760	26639	8,303	9/14/2022	9/26/2022	12	0.002%	0.0003
4000467761	26643	1,749	9/14/2022	9/26/2022	12	0.000%	0.0001
4000467767	34348	90	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467717	15871	1,527	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467724	113528	1,000	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467727	123882	1,500	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467742	145120	64,000	9/14/2022	9/26/2022	12	0.017%	0.0020
4000467745	145345	500	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467746	145349	500	9/14/2022	9/26/2022	12	0.000%	0.0000
4000467812	9673	1,050	9/15/2022	9/27/2022	12	0.000%	0.0000
4000467819	26490	1,647	9/15/2022	9/27/2022	12	0.000%	0.0001
4000467821	30475	26,628	9/15/2022	9/27/2022	12	0.007%	0.0008
4000467822	30475	28,149	9/15/2022	9/27/2022	12	0.007%	0.0009
4000467823	30475	18,376	9/15/2022	9/27/2022	12	0.005%	0.0006
4000467824	30475	22,723	9/15/2022	9/27/2022	12	0.006%	0.0007
4000467793	115726	75,000	9/15/2022	9/27/2022	12	0.020%	0.0024
4000467807	142942	1,186	9/15/2022	9/27/2022	12	0.000%	0.0000
4000467810	145208	2,784	9/15/2022	9/27/2022	12	0.001%	0.0001
4000467872	27013	25,174	9/16/2022	9/28/2022	12	0.007%	0.0008
4000467880	34064	406	9/16/2022	9/28/2022	12	0.000%	0.0000
4000467884	106699	17,976	9/16/2022	9/28/2022	12	0.005%	0.0006
4000467838	15871	10,371	9/16/2022	9/28/2022	12	0.003%	0.0003
4000467846	125723	223	9/16/2022	9/28/2022	12	0.000%	0.0000
4000467852	140752	3,955	9/16/2022	9/28/2022	12	0.001%	0.0001
4000467859	144358	103,409	9/16/2022	9/28/2022	12	0.027%	0.0033
4000467975	25272	6,205	9/21/2022	10/3/2022	12	0.002%	0.0002
4000467954	34888	20	9/21/2022	10/3/2022	12	0.000%	0.0000
4000467964	141826	20,329	9/21/2022	10/3/2022	12	0.005%	0.0006
4000467971	144881	16,893	9/21/2022	10/3/2022	12	0.004%	0.0005
4000468009	9891	8,197	9/22/2022	10/4/2022	12	0.002%	0.0003
4000468013	26490	407	9/22/2022	10/4/2022	12	0.000%	0.0000
4000467989	104872	480	9/22/2022	10/4/2022	12	0.000%	0.0000
4000467993	119251	12,793	9/22/2022	10/4/2022	12	0.003%	0.0004
4000467994	123377	3,778	9/22/2022	10/4/2022	12	0.001%	0.0001
4000468004	144487	14,418	9/22/2022	10/4/2022	12	0.004%	0.0005
4000468071	11260	7,585	9/23/2022	10/5/2022	12	0.002%	0.0002
4000468075	25659	13,948	9/23/2022	10/5/2022	12	0.004%	0.0004
4000468077	26213	6,072	9/23/2022	10/5/2022	12	0.002%	0.0002
4000468079	26577	3,100	9/23/2022	10/5/2022	12	0.001%	0.0001
4000468081	28084	10,023	9/23/2022	10/5/2022	12	0.003%	0.0003
4000468084	30257	63,978	9/23/2022	10/5/2022	12	0.017%	0.0020
4000468030	15871	18,374	9/23/2022	10/5/2022	12	0.005%	0.0006
4000468055	138862	208	9/23/2022	10/5/2022	12	0.000%	0.0000
4000468066	144479	413,581	9/23/2022	10/5/2022	12	0.109%	0.0131

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468288	11372	1,813	9/29/2022	10/11/2022	12	0.000%	0.0001
4000468308	134272	4,353	9/29/2022	10/11/2022	12	0.001%	0.0001
4000468273	125742	4,980	9/29/2022	10/11/2022	12	0.001%	0.0002
4000468275	142926	98,812	9/29/2022	10/11/2022	12	0.026%	0.0031
4000468282	144530	8,200	9/29/2022	10/11/2022	12	0.002%	0.0003
4000468400	14949	1,272	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468415	33731	10,369	9/30/2022	10/12/2022	12	0.003%	0.0003
4000468416	33956	1,613	9/30/2022	10/12/2022	12	0.000%	0.0001
4000468418	34064	241,446	9/30/2022	10/12/2022	12	0.064%	0.0076
4000468419	34341	7,000	9/30/2022	10/12/2022	12	0.002%	0.0002
4000468424	109948	8,149	9/30/2022	10/12/2022	12	0.002%	0.0003
4000468310	4502	3,575	9/30/2022	10/12/2022	12	0.001%	0.0001
4000468311	4502	15,582	9/30/2022	10/12/2022	12	0.004%	0.0005
4000468314	20287	413	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468324	104983	1,240	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468329	110291	13,297	9/30/2022	10/12/2022	12	0.004%	0.0004
4000468333	116850	431	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468336	118807	347	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468340	130634	27,693	9/30/2022	10/12/2022	12	0.007%	0.0009
4000468342	133414	5,540	9/30/2022	10/12/2022	12	0.001%	0.0002
4000468343	134862	1,595,038	9/30/2022	10/12/2022	12	0.421%	0.0505
4000468346	139487	1,536	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468348	141025	18,000	9/30/2022	10/12/2022	12	0.005%	0.0006
4000468350	141370	13,250	9/30/2022	10/12/2022	12	0.003%	0.0004
4000468352	141831	11,880	9/30/2022	10/12/2022	12	0.003%	0.0004
4000468359	142787	10,565	9/30/2022	10/12/2022	12	0.003%	0.0003
4000468361	142926	53,746	9/30/2022	10/12/2022	12	0.014%	0.0017
4000468363	143011	39,464	9/30/2022	10/12/2022	12	0.010%	0.0012
4000468364	143072	27,450	9/30/2022	10/12/2022	12	0.007%	0.0009
4000468366	143312	91,763	9/30/2022	10/12/2022	12	0.024%	0.0029
4000468367	143340	7,534	9/30/2022	10/12/2022	12	0.002%	0.0002
4000468369	143520	2,219	9/30/2022	10/12/2022	12	0.001%	0.0001
4000468371	143606	271,632	9/30/2022	10/12/2022	12	0.072%	0.0086
4000468372	143659	65,009	9/30/2022	10/12/2022	12	0.017%	0.0021
4000468378	144510	2,000	9/30/2022	10/12/2022	12	0.001%	0.0001
4000468380	144567	9,000	9/30/2022	10/12/2022	12	0.002%	0.0003
4000468381	144573	4,000	9/30/2022	10/12/2022	12	0.001%	0.0001
4000468382	144741	1,498	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468383	144773	625	9/30/2022	10/12/2022	12	0.000%	0.0000
4000468385	144878	2,716	9/30/2022	10/12/2022	12	0.001%	0.0001
4000468496	34341	7,700	10/5/2022	10/17/2022	12	0.002%	0.0002
4000468488	107047	23,056	10/5/2022	10/17/2022	12	0.006%	0.0007
4000468580	11426	902	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468587	26016	1,012	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468589	26639	2,228	10/7/2022	10/19/2022	12	0.001%	0.0001
4000468590	27013	5,653	10/7/2022	10/19/2022	12	0.001%	0.0002
4000468593	27982	1,960	10/7/2022	10/19/2022	12	0.001%	0.0001
4000468606	33203	360	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468610	104725	1,375	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468538	7214	351,152	10/7/2022	10/19/2022	12	0.093%	0.0111
4000468539	15871	8,203	10/7/2022	10/19/2022	12	0.002%	0.0003
4000468540	15871	11,277	10/7/2022	10/19/2022	12	0.003%	0.0004
4000468547	102558	53,823	10/7/2022	10/19/2022	12	0.014%	0.0017

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468548	103114	993	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468550	103620	245	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468552	104872	1,098	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468555	110291	108,645	10/7/2022	10/19/2022	12	0.029%	0.0034
4000468556	111669	60	10/7/2022	10/19/2022	12	0.000%	0.0000
4000468560	142926	82,034	10/7/2022	10/19/2022	12	0.022%	0.0026
4000468739	117331	1,900	10/12/2022	10/24/2022	12	0.001%	0.0001
4000468680	103603	13,506	10/12/2022	10/24/2022	12	0.004%	0.0004
4000468692	117205	2,000	10/12/2022	10/24/2022	12	0.001%	0.0001
4000468703	134862	531,489	10/12/2022	10/24/2022	12	0.140%	0.0168
4000468708	140286	2,500	10/12/2022	10/24/2022	12	0.001%	0.0001
4000468776	27982	3,320	10/13/2022	10/25/2022	12	0.001%	0.0001
4000468781	117331	43,800	10/13/2022	10/25/2022	12	0.012%	0.0014
4000468742	4502	17,342	10/13/2022	10/25/2022	12	0.005%	0.0005
4000468744	24383	2,670	10/13/2022	10/25/2022	12	0.001%	0.0001
4000468747	105195	1,081	10/13/2022	10/25/2022	12	0.000%	0.0000
4000468751	116384	79	10/13/2022	10/25/2022	12	0.000%	0.0000
4000468760	144084	22,428	10/13/2022	10/25/2022	12	0.006%	0.0007
4000468762	144816	16,098	10/13/2022	10/25/2022	12	0.004%	0.0005
4000468820	11577	5,828	10/14/2022	10/26/2022	12	0.002%	0.0002
4000468836	32537	605	10/14/2022	10/26/2022	12	0.000%	0.0000
4000468791	34888	27	10/14/2022	10/26/2022	12	0.000%	0.0000
4000468800	141203	152,951	10/14/2022	10/26/2022	12	0.040%	0.0048
4000468803	142885	33,460	10/14/2022	10/26/2022	12	0.009%	0.0011
4000468804	142926	7,412	10/14/2022	10/26/2022	12	0.002%	0.0002
4000468807	143072	7,547	10/14/2022	10/26/2022	12	0.002%	0.0002
4000468951	11372	1,664	10/19/2022	10/31/2022	12	0.000%	0.0001
4000468952	18267	3,476	10/19/2022	10/31/2022	12	0.001%	0.0001
4000468957	25809	11,134	10/19/2022	10/31/2022	12	0.003%	0.0004
4000468937	6396	89,208	10/19/2022	10/31/2022	12	0.024%	0.0028
4000468941	116902	33,100	10/19/2022	10/31/2022	12	0.009%	0.0010
4000468945	142942	3,705	10/19/2022	10/31/2022	12	0.001%	0.0001
4000468975	32946	6,654	10/19/2022	10/31/2022	12	0.002%	0.0002
4000468978	32952	33,335	10/19/2022	10/31/2022	12	0.009%	0.0011
4000468992	33005	1,847	10/19/2022	10/31/2022	12	0.000%	0.0001
4000469012	33070	14,078	10/19/2022	10/31/2022	12	0.004%	0.0004
4000469013	33073	2,428	10/19/2022	10/31/2022	12	0.001%	0.0001
4000469015	33076	43,629	10/19/2022	10/31/2022	12	0.012%	0.0014
4000469027	33139	30,016	10/19/2022	10/31/2022	12	0.008%	0.0010
4000469031	124628	3,936	10/19/2022	10/31/2022	12	0.001%	0.0001
4000469055	8392	11,204	10/20/2022	11/1/2022	12	0.003%	0.0004
4000469039	104872	28	10/20/2022	11/1/2022	12	0.000%	0.0000
4000469044	126928	37	10/20/2022	11/1/2022	12	0.000%	0.0000
4000469110	14060	550	10/21/2022	11/2/2022	12	0.000%	0.0000
4000469111	18267	18,950	10/21/2022	11/2/2022	12	0.005%	0.0006
4000469120	32356	1,916	10/21/2022	11/2/2022	12	0.001%	0.0001
4000469127	105195	3,621	10/21/2022	11/2/2022	12	0.001%	0.0001
4000469077	15871	8,912	10/21/2022	11/2/2022	12	0.002%	0.0003
4000469081	34888	20	10/21/2022	11/2/2022	12	0.000%	0.0000
4000469082	104496	37	10/21/2022	11/2/2022	12	0.000%	0.0000
4000469084	105195	18,154	10/21/2022	11/2/2022	12	0.005%	0.0006
4000469093	134862	742,139	10/21/2022	11/2/2022	12	0.196%	0.0235
4000469102	143502	1,303	10/21/2022	11/2/2022	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469105	144982	95,533	10/21/2022	11/2/2022	12	0.025%	0.0030
4000469106	145055	5,849	10/21/2022	11/2/2022	12	0.002%	0.0002
4000469244	27389	9,890	10/26/2022	11/7/2022	12	0.003%	0.0003
4000469245	27962	6,326	10/26/2022	11/7/2022	12	0.002%	0.0002
4000469209	103603	2,195	10/26/2022	11/7/2022	12	0.001%	0.0001
4000469211	108092	2,060	10/26/2022	11/7/2022	12	0.001%	0.0001
4000469221	121825	12,479	10/26/2022	11/7/2022	12	0.003%	0.0004
4000469231	145141	297	10/26/2022	11/7/2022	12	0.000%	0.0000
4000469232	145251	1,439	10/26/2022	11/7/2022	12	0.000%	0.0000
4000469296	18267	9,340	10/27/2022	11/8/2022	12	0.002%	0.0003
4000469312	27162	4,426	10/27/2022	11/8/2022	12	0.001%	0.0001
4000469315	32897	1,200	10/27/2022	11/8/2022	12	0.000%	0.0000
4000469321	124628	1,072	10/27/2022	11/8/2022	12	0.000%	0.0000
4000469269	104872	168	10/27/2022	11/8/2022	12	0.000%	0.0000
4000469327	32989	5,169	10/27/2022	11/8/2022	12	0.001%	0.0002
4000469369	18267	3,616	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469375	25599	3,919	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469377	26604	2,350	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469381	27013	3,616	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469384	28474	605	10/28/2022	11/9/2022	12	0.000%	0.0000
4000469387	30475	73,872	10/28/2022	11/9/2022	12	0.019%	0.0023
4000469394	34658	4,000	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469395	34937	12,000	10/28/2022	11/9/2022	12	0.003%	0.0004
4000469396	105195	2,640	10/28/2022	11/9/2022	12	0.001%	0.0001
4000469331	27094	6,180	10/28/2022	11/9/2022	12	0.002%	0.0002
4000469335	105195	10,509	10/28/2022	11/9/2022	12	0.003%	0.0003
4000469343	132097	115,337	10/28/2022	11/9/2022	12	0.030%	0.0037
4000469348	142926	219,932	10/28/2022	11/9/2022	12	0.058%	0.0070
4000469540	32808	1,320	11/2/2022	11/14/2022	12	0.000%	0.0000
4000469541	32875	700	11/2/2022	11/14/2022	12	0.000%	0.0000
4000469544	34658	2,500	11/2/2022	11/14/2022	12	0.001%	0.0001
4000469489	15871	2,286	11/2/2022	11/14/2022	12	0.001%	0.0001
4000469509	142164	5,356	11/2/2022	11/14/2022	12	0.001%	0.0002
4000469515	144015	10,000	11/2/2022	11/14/2022	12	0.003%	0.0003
4000469519	144510	2,000	11/2/2022	11/14/2022	12	0.001%	0.0001
4000469529	145187	10,000	11/2/2022	11/14/2022	12	0.003%	0.0003
4000469531	145456	12,808	11/2/2022	11/14/2022	12	0.003%	0.0004
4000469581	18267	7,275	11/3/2022	11/15/2022	12	0.002%	0.0002
4000469584	26604	17,500	11/3/2022	11/15/2022	12	0.005%	0.0006
4000469585	26655	1,005	11/3/2022	11/15/2022	12	0.000%	0.0000
4000469591	30475	38,107	11/3/2022	11/15/2022	12	0.010%	0.0012
4000469596	105195	1,111	11/3/2022	11/15/2022	12	0.000%	0.0000
4000469565	142942	523	11/3/2022	11/15/2022	12	0.000%	0.0000
4000469570	143880	1,800	11/3/2022	11/15/2022	12	0.000%	0.0001
4000469575	145181	1,350	11/3/2022	11/15/2022	12	0.000%	0.0000
4000469576	145295	1,355	11/3/2022	11/15/2022	12	0.000%	0.0000
4000469637	17342	1,080	11/4/2022	11/16/2022	12	0.000%	0.0000
4000469639	24765	3,342	11/4/2022	11/16/2022	12	0.001%	0.0001
4000469643	26297	7,038	11/4/2022	11/16/2022	12	0.002%	0.0002
4000469646	26655	955	11/4/2022	11/16/2022	12	0.000%	0.0000
4000469604	6396	8,921	11/4/2022	11/16/2022	12	0.002%	0.0003
4000469607	15871	8,409	11/4/2022	11/16/2022	12	0.002%	0.0003
4000469621	132507	125,813	11/4/2022	11/16/2022	12	0.033%	0.0040

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469624	141256	17	11/4/2022	11/16/2022	12	0.000%	0.0000
4000469626	142942	23,152	11/4/2022	11/16/2022	12	0.006%	0.0007
4000469752	25808	17,700	11/9/2022	11/21/2022	12	0.005%	0.0006
4000469762	30475	71,580	11/9/2022	11/21/2022	12	0.019%	0.0023
4000469763	30475	62,811	11/9/2022	11/21/2022	12	0.017%	0.0020
4000469718	111078	1,000	11/9/2022	11/21/2022	12	0.000%	0.0000
4000469722	125830	1,000	11/9/2022	11/21/2022	12	0.000%	0.0000
4000469735	144422	76,024	11/9/2022	11/21/2022	12	0.020%	0.0024
4000469739	145056	461,771	11/9/2022	11/21/2022	12	0.122%	0.0146
4000469740	145458	5,000	11/9/2022	11/21/2022	12	0.001%	0.0002
4000469814	13911	860	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469815	18267	11,940	11/10/2022	11/22/2022	12	0.003%	0.0004
4000469820	26604	3,855	11/10/2022	11/22/2022	12	0.001%	0.0001
4000469824	33956	2,386	11/10/2022	11/22/2022	12	0.001%	0.0001
4000469825	34064	251	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469826	34341	1,325	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469828	34658	2,500	11/10/2022	11/22/2022	12	0.001%	0.0001
4000469829	117331	1,192	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469773	4502	6,336	11/10/2022	11/22/2022	12	0.002%	0.0002
4000469774	4502	177,056	11/10/2022	11/22/2022	12	0.047%	0.0056
4000469779	27094	4,415	11/10/2022	11/22/2022	12	0.001%	0.0001
4000469781	36403	2,899	11/10/2022	11/22/2022	12	0.001%	0.0001
4000469783	105195	1,766	11/10/2022	11/22/2022	12	0.000%	0.0001
4000469787	118807	53	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469790	127085	5,915	11/10/2022	11/22/2022	12	0.002%	0.0002
4000469792	134862	110,317	11/10/2022	11/22/2022	12	0.029%	0.0035
4000469794	138862	99	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469795	141256	215	11/10/2022	11/22/2022	12	0.000%	0.0000
4000469796	142926	84,415	11/10/2022	11/22/2022	12	0.022%	0.0027
4000469801	143340	20,969	11/10/2022	11/22/2022	12	0.006%	0.0007
4000469802	143477	6,500	11/10/2022	11/22/2022	12	0.002%	0.0002
4000469807	144567	9,450	11/10/2022	11/22/2022	12	0.002%	0.0003
4000469808	144567	27,344	11/10/2022	11/22/2022	12	0.007%	0.0009
4000469809	144567	16,249	11/10/2022	11/22/2022	12	0.004%	0.0005
4000469810	144835	33,435	11/10/2022	11/22/2022	12	0.009%	0.0011
4000469924	25938	19,782	11/16/2022	11/28/2022	12	0.005%	0.0006
4000469957	11260	1,750	11/17/2022	11/29/2022	12	0.000%	0.0001
4000469960	24825	1,960	11/17/2022	11/29/2022	12	0.001%	0.0001
4000469962	28084	11,970	11/17/2022	11/29/2022	12	0.003%	0.0004
4000469963	30580	7,490	11/17/2022	11/29/2022	12	0.002%	0.0002
4000469972	142942	1,219	11/17/2022	11/29/2022	12	0.000%	0.0000
4000469973	143072	3,889	11/17/2022	11/29/2022	12	0.001%	0.0001
4000470027	18275	5,265	11/18/2022	11/30/2022	12	0.001%	0.0002
4000470029	24113	11,775	11/18/2022	11/30/2022	12	0.003%	0.0004
4000470035	25667	800	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470038	26639	810	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470040	26644	48,735	11/18/2022	11/30/2022	12	0.013%	0.0015
4000470044	30475	61,723	11/18/2022	11/30/2022	12	0.016%	0.0020
4000470045	30475	70,564	11/18/2022	11/30/2022	12	0.019%	0.0022
4000470046	30475	54,527	11/18/2022	11/30/2022	12	0.014%	0.0017
4000470049	34616	19,586	11/18/2022	11/30/2022	12	0.005%	0.0006
4000469996	15871	3,871	11/18/2022	11/30/2022	12	0.001%	0.0001
4000469999	28084	81,178	11/18/2022	11/30/2022	12	0.021%	0.0026

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470002	103392	17	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470003	103404	53	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470008	125742	144	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470012	138494	10,200	11/18/2022	11/30/2022	12	0.003%	0.0003
4000470013	139733	354	11/18/2022	11/30/2022	12	0.000%	0.0000
4000470151	20287	344	11/23/2022	12/5/2022	12	0.000%	0.0000
4000470157	110291	46,979	11/23/2022	12/5/2022	12	0.012%	0.0015
4000470158	110291	16,843	11/23/2022	12/5/2022	12	0.004%	0.0005
4000470163	125742	4,851	11/23/2022	12/5/2022	12	0.001%	0.0002
4000470164	129859	378,050	11/23/2022	12/5/2022	12	0.100%	0.0120
4000470166	138494	36,719	11/23/2022	12/5/2022	12	0.010%	0.0012
4000470170	142700	11,505	11/23/2022	12/5/2022	12	0.003%	0.0004
4000470171	142926	176,962	11/23/2022	12/5/2022	12	0.047%	0.0056
4000470177	143463	143,741	11/23/2022	12/5/2022	12	0.038%	0.0045
4000470179	143694	450	11/23/2022	12/5/2022	12	0.000%	0.0000
4000470180	143796	27,757	11/23/2022	12/5/2022	12	0.007%	0.0009
4000470184	144097	103,838	11/23/2022	12/5/2022	12	0.027%	0.0033
4000470187	144830	50,588	11/23/2022	12/5/2022	12	0.013%	0.0016
4000470347	11577	1,785	11/30/2022	12/12/2022	12	0.000%	0.0001
4000470348	13911	77,720	11/30/2022	12/12/2022	12	0.020%	0.0025
4000470352	24113	18,250	11/30/2022	12/12/2022	12	0.005%	0.0006
4000470354	25599	868	11/30/2022	12/12/2022	12	0.000%	0.0000
4000470356	25708	6,263	11/30/2022	12/12/2022	12	0.002%	0.0002
4000470367	27704	8,750	11/30/2022	12/12/2022	12	0.002%	0.0003
4000470381	34341	7,700	11/30/2022	12/12/2022	12	0.002%	0.0002
4000470388	134272	84,271	11/30/2022	12/12/2022	12	0.022%	0.0027
4000470343	145258	366	11/30/2022	12/12/2022	12	0.000%	0.0000
4000470394	15871	490	12/1/2022	12/13/2022	12	0.000%	0.0000
4000470399	104872	89	12/1/2022	12/13/2022	12	0.000%	0.0000
4000470400	105195	15,000	12/1/2022	12/13/2022	12	0.004%	0.0005
4000470417	142642	1,867	12/1/2022	12/13/2022	12	0.000%	0.0001
4000470421	142942	3,810	12/1/2022	12/13/2022	12	0.001%	0.0001
4000470429	145222	9,338	12/1/2022	12/13/2022	12	0.002%	0.0003
4000470453	15871	5,485	12/2/2022	12/14/2022	12	0.001%	0.0002
4000470454	26958	590	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470457	103114	26	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470458	103392	1,557	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470464	129855	427	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470467	134906	3,900	12/2/2022	12/14/2022	12	0.001%	0.0001
4000470473	141370	13,250	12/2/2022	12/14/2022	12	0.003%	0.0004
4000470478	142164	5,356	12/2/2022	12/14/2022	12	0.001%	0.0002
4000470482	142787	10,565	12/2/2022	12/14/2022	12	0.003%	0.0003
4000470487	143072	2,828	12/2/2022	12/14/2022	12	0.001%	0.0001
4000470488	143111	2,800	12/2/2022	12/14/2022	12	0.001%	0.0001
4000470489	143243	71,808	12/2/2022	12/14/2022	12	0.019%	0.0023
4000470497	143929	52,458	12/2/2022	12/14/2022	12	0.014%	0.0017
4000470503	144567	13,000	12/2/2022	12/14/2022	12	0.003%	0.0004
4000470509	144986	4,000	12/2/2022	12/14/2022	12	0.001%	0.0001
4000470512	145034	11,345	12/2/2022	12/14/2022	12	0.003%	0.0004
4000470516	145181	1,350	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470519	145295	1,355	12/2/2022	12/14/2022	12	0.000%	0.0000
4000470520	145341	4,688	12/2/2022	12/14/2022	12	0.001%	0.0001
4000470629	9121	1,800	12/7/2022	12/19/2022	12	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470611	116384	1,040	12/7/2022	12/19/2022	12	0.000%	0.0000
4000470617	141610	151,373	12/7/2022	12/19/2022	12	0.040%	0.0048
4000470619	142615	37,919	12/7/2022	12/19/2022	12	0.010%	0.0012
4000470620	142926	1,094	12/7/2022	12/19/2022	12	0.000%	0.0000
4000470628	145251	480	12/7/2022	12/19/2022	12	0.000%	0.0000
4000470670	18267	1,620	12/8/2022	12/20/2022	12	0.000%	0.0001
4000470677	26493	3,241	12/8/2022	12/20/2022	12	0.001%	0.0001
4000470649	25147	32,479	12/8/2022	12/20/2022	12	0.009%	0.0010
4000470654	107047	22,968	12/8/2022	12/20/2022	12	0.006%	0.0007
4000470722	9673	8,400	12/9/2022	12/21/2022	12	0.002%	0.0003
4000470728	26356	1,734	12/9/2022	12/21/2022	12	0.000%	0.0001
4000470732	26659	8,291	12/9/2022	12/21/2022	12	0.002%	0.0003
4000470734	28737	945	12/9/2022	12/21/2022	12	0.000%	0.0000
4000470697	15871	1,766	12/9/2022	12/21/2022	12	0.000%	0.0001
4000470699	32869	8,500	12/9/2022	12/21/2022	12	0.002%	0.0003
4000470703	134862	216,023	12/9/2022	12/21/2022	12	0.057%	0.0068
4000470712	143577	6,718	12/9/2022	12/21/2022	12	0.002%	0.0002
4000470903	10384	73,650	12/15/2022	12/27/2022	12	0.019%	0.0023
4000470905	18267	6,994	12/15/2022	12/27/2022	12	0.002%	0.0002
4000470881	105195	34,351	12/15/2022	12/27/2022	12	0.009%	0.0011
4000470882	105195	29,748	12/15/2022	12/27/2022	12	0.008%	0.0009
4000470895	143072	604	12/15/2022	12/27/2022	12	0.000%	0.0000
4000470900	145388	1,604	12/15/2022	12/27/2022	12	0.000%	0.0001
4000471001	18267	7,781	12/16/2022	12/28/2022	12	0.002%	0.0002
4000471005	25083	3,024	12/16/2022	12/28/2022	12	0.001%	0.0001
4000471009	28474	484	12/16/2022	12/28/2022	12	0.000%	0.0000
4000471017	32538	974	12/16/2022	12/28/2022	12	0.000%	0.0000
4000471019	34064	843	12/16/2022	12/28/2022	12	0.000%	0.0000
4000471020	34341	24,425	12/16/2022	12/28/2022	12	0.006%	0.0008
4000470920	4502	459	12/16/2022	12/28/2022	12	0.000%	0.0000
4000470922	21678	1,772	12/16/2022	12/28/2022	12	0.000%	0.0001
4000470928	105195	12,458	12/16/2022	12/28/2022	12	0.003%	0.0004
4000470930	108092	2,060	12/16/2022	12/28/2022	12	0.001%	0.0001
4000470932	115761	923	12/16/2022	12/28/2022	12	0.000%	0.0000
4000470934	118807	3,024	12/16/2022	12/28/2022	12	0.001%	0.0001
4000470935	119139	15,093	12/16/2022	12/28/2022	12	0.004%	0.0005
4000470936	121825	3,177	12/16/2022	12/28/2022	12	0.001%	0.0001
4000470940	125742	32,969	12/16/2022	12/28/2022	12	0.009%	0.0010
4000470944	129855	427	12/16/2022	12/28/2022	12	0.000%	0.0000
4000470946	134862	1,302,542	12/16/2022	12/28/2022	12	0.344%	0.0412
4000470949	138494	8,000	12/16/2022	12/28/2022	12	0.002%	0.0003
4000470961	142635	6,710	12/16/2022	12/28/2022	12	0.002%	0.0002
4000470968	143477	5,267	12/16/2022	12/28/2022	12	0.001%	0.0002
4000470973	144084	40,650	12/16/2022	12/28/2022	12	0.011%	0.0013
4000470974	144097	4,178,487	12/16/2022	12/28/2022	12	1.102%	0.1323
4000470982	144816	1,098	12/16/2022	12/28/2022	12	0.000%	0.0000
4000470987	144982	15,163	12/16/2022	12/28/2022	12	0.004%	0.0005
4000471181	112215	3,360	12/22/2022	1/3/2023	12	0.001%	0.0001
4000471246	18267	5,013	12/23/2022	1/4/2023	12	0.001%	0.0002
4000471261	33956	8,698	12/23/2022	1/4/2023	12	0.002%	0.0003
4000471262	34341	7,000	12/23/2022	1/4/2023	12	0.002%	0.0002
4000471264	34658	2,500	12/23/2022	1/4/2023	12	0.001%	0.0001
4000471265	105195	1,309	12/23/2022	1/4/2023	12	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471218	4502	1,378	12/23/2022	1/4/2023	12	0.000%	0.0000
4000471220	15871	490	12/23/2022	1/4/2023	12	0.000%	0.0000
4000471227	103392	321	12/23/2022	1/4/2023	12	0.000%	0.0000
4000471228	105195	10,511	12/23/2022	1/4/2023	12	0.003%	0.0003
4000471235	143011	38,624	12/23/2022	1/4/2023	12	0.010%	0.0012
4000471237	143477	28,399	12/23/2022	1/4/2023	12	0.007%	0.0009
4000471238	144567	6,916	12/23/2022	1/4/2023	12	0.002%	0.0002
4000471328	28737	547	12/28/2022	1/9/2023	12	0.000%	0.0000
4000471304	36413	76,321	12/28/2022	1/9/2023	12	0.020%	0.0024
4000471305	104473	9,800	12/28/2022	1/9/2023	12	0.003%	0.0003
4000471311	142926	20,718	12/28/2022	1/9/2023	12	0.005%	0.0007
4000471379	24113	7,210	12/29/2022	1/10/2023	12	0.002%	0.0002
4000471382	24765	3,519	12/29/2022	1/10/2023	12	0.001%	0.0001
4000471385	25599	1,045	12/29/2022	1/10/2023	12	0.000%	0.0000
4000471387	25808	19,080	12/29/2022	1/10/2023	12	0.005%	0.0006
4000471392	26356	16,473	12/29/2022	1/10/2023	12	0.004%	0.0005
4000471340	4831	40,850	12/29/2022	1/10/2023	12	0.011%	0.0013
4000471354	130875	350	12/29/2022	1/10/2023	12	0.000%	0.0000
4000471357	142942	541	12/29/2022	1/10/2023	12	0.000%	0.0000
4000471482	11579	53,406	12/30/2022	1/11/2023	12	0.014%	0.0017
4000471483	18267	14,879	12/30/2022	1/11/2023	12	0.004%	0.0005
4000471486	24385	1,137	12/30/2022	1/11/2023	12	0.000%	0.0000
4000471495	26674	1,120	12/30/2022	1/11/2023	12	0.000%	0.0000
4000471499	28474	3,293	12/30/2022	1/11/2023	12	0.001%	0.0001
4000471510	32538	2,601	12/30/2022	1/11/2023	12	0.001%	0.0001
4000471514	34064	240,815	12/30/2022	1/11/2023	12	0.064%	0.0076
4000471515	34531	14,177	12/30/2022	1/11/2023	12	0.004%	0.0004
4000471517	34658	2,500	12/30/2022	1/11/2023	12	0.001%	0.0001
4000471519	34937	12,000	12/30/2022	1/11/2023	12	0.003%	0.0004
4000471520	105195	16,881	12/30/2022	1/11/2023	12	0.004%	0.0005
4000471417	4502	27,552	12/30/2022	1/11/2023	12	0.007%	0.0009
4000471428	105195	33,777	12/30/2022	1/11/2023	12	0.009%	0.0011
4000471434	113967	1,750	12/30/2022	1/11/2023	12	0.000%	0.0001
4000471442	133926	1,192	12/30/2022	1/11/2023	12	0.000%	0.0000
4000471443	134862	1,498,911	12/30/2022	1/11/2023	12	0.395%	0.0474
4000471450	143312	94,501	12/30/2022	1/11/2023	12	0.025%	0.0030
4000471453	143463	5,420	12/30/2022	1/11/2023	12	0.001%	0.0002
4000471454	143463	29,397	12/30/2022	1/11/2023	12	0.008%	0.0009
4000471458	143619	15,981	12/30/2022	1/11/2023	12	0.004%	0.0005
4000471460	143727	41,587	12/30/2022	1/11/2023	12	0.011%	0.0013
4000471466	144567	1,644	12/30/2022	1/11/2023	12	0.000%	0.0001
4000471472	145295	1,355	12/30/2022	1/11/2023	12	0.000%	0.0000
4000471474	145388	34,031	12/30/2022	1/11/2023	12	0.009%	0.0011
4000471478	145527	10,889	12/30/2022	1/11/2023	12	0.003%	0.0003
4000459597	142635	45,698	1/5/2022	1/18/2022	13	0.012%	0.0016
4000459599	143577	8,754	1/5/2022	1/18/2022	13	0.002%	0.0003
4000459653	34391	796,808	1/6/2022	1/19/2022	13	0.210%	0.0273
4000459609	4208	47,850	1/6/2022	1/19/2022	13	0.013%	0.0016
4000459610	4502	16,676	1/6/2022	1/19/2022	13	0.004%	0.0006
4000459619	118807	515	1/6/2022	1/19/2022	13	0.000%	0.0000
4000459622	130811	150,000	1/6/2022	1/19/2022	13	0.040%	0.0051
4000459624	134664	5,965	1/6/2022	1/19/2022	13	0.002%	0.0002
4000459625	134862	1,891,132	1/6/2022	1/19/2022	13	0.499%	0.0648

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459628	141101	45,812	1/6/2022	1/19/2022	13	0.012%	0.0016
4000459634	143694	2,037	1/6/2022	1/19/2022	13	0.001%	0.0001
4000459638	144519	38,793	1/6/2022	1/19/2022	13	0.010%	0.0013
4000459639	144540	68,300	1/6/2022	1/19/2022	13	0.018%	0.0023
4000459690	27013	187	1/7/2022	1/20/2022	13	0.000%	0.0000
4000459663	33770	23,933	1/7/2022	1/20/2022	13	0.006%	0.0008
4000459664	103392	1,539	1/7/2022	1/20/2022	13	0.000%	0.0001
4000459756	18267	5,112	1/11/2022	1/24/2022	13	0.001%	0.0002
4000459761	25437	900	1/11/2022	1/24/2022	13	0.000%	0.0000
4000459766	30475	52,744	1/11/2022	1/24/2022	13	0.014%	0.0018
4000459767	30475	59,992	1/11/2022	1/24/2022	13	0.016%	0.0021
4000459746	104872	738	1/11/2022	1/24/2022	13	0.000%	0.0000
4000459752	143340	83,538	1/11/2022	1/24/2022	13	0.022%	0.0029
4000459803	34348	1,590	1/12/2022	1/25/2022	13	0.000%	0.0001
4000459867	26643	8,487	1/13/2022	1/26/2022	13	0.002%	0.0003
4000459870	30475	64,831	1/13/2022	1/26/2022	13	0.017%	0.0022
4000459816	6396	8,334	1/13/2022	1/26/2022	13	0.002%	0.0003
4000459819	15871	15,719	1/13/2022	1/26/2022	13	0.004%	0.0005
4000459827	104509	11,478	1/13/2022	1/26/2022	13	0.003%	0.0004
4000459833	116384	441	1/13/2022	1/26/2022	13	0.000%	0.0000
4000459837	135488	27,724	1/13/2022	1/26/2022	13	0.007%	0.0010
4000459838	138975	13,402	1/13/2022	1/26/2022	13	0.004%	0.0005
4000459841	142613	8,419	1/13/2022	1/26/2022	13	0.002%	0.0003
4000459842	142926	24,030	1/13/2022	1/26/2022	13	0.006%	0.0008
4000459887	105195	8,171	1/14/2022	1/27/2022	13	0.002%	0.0003
4000459896	143962	566,700	1/14/2022	1/27/2022	13	0.149%	0.0194
4000459915	32936	94,994	1/14/2022	1/27/2022	13	0.025%	0.0033
4000459922	32946	11,791	1/14/2022	1/27/2022	13	0.003%	0.0004
4000459925	32949	79,236	1/14/2022	1/27/2022	13	0.021%	0.0027
4000459927	32951	21,974	1/14/2022	1/27/2022	13	0.006%	0.0008
4000459928	32956	9,690	1/14/2022	1/27/2022	13	0.003%	0.0003
4000459929	32961	82,832	1/14/2022	1/27/2022	13	0.022%	0.0028
4000459931	32965	10,043	1/14/2022	1/27/2022	13	0.003%	0.0003
4000459937	32972	8,278	1/14/2022	1/27/2022	13	0.002%	0.0003
4000459939	32981	48,850	1/14/2022	1/27/2022	13	0.013%	0.0017
4000459949	32999	13,182	1/14/2022	1/27/2022	13	0.003%	0.0005
4000459880	114121	4,025	1/14/2022	1/27/2022	13	0.001%	0.0001
4000459991	24114	1,980	1/18/2022	1/31/2022	13	0.001%	0.0001
4000460005	33770	33,950	1/18/2022	1/31/2022	13	0.009%	0.0012
4000459955	5089	45,765	1/18/2022	1/31/2022	13	0.012%	0.0016
4000459956	10384	3,400	1/18/2022	1/31/2022	13	0.001%	0.0001
4000459974	143941	66,128	1/18/2022	1/31/2022	13	0.017%	0.0023
4000459981	144794	12,600	1/18/2022	1/31/2022	13	0.003%	0.0004
4000460025	143577	10,950	1/19/2022	2/1/2022	13	0.003%	0.0004
4000460054	6396	5,950	1/20/2022	2/2/2022	13	0.002%	0.0002
4000460126	135537	14,112	1/21/2022	2/3/2022	13	0.004%	0.0005
4000460104	102558	30,756	1/21/2022	2/3/2022	13	0.008%	0.0011
4000460105	103008	2,421	1/21/2022	2/3/2022	13	0.001%	0.0001
4000460107	103392	257	1/21/2022	2/3/2022	13	0.000%	0.0000
4000460115	126928	183	1/21/2022	2/3/2022	13	0.000%	0.0000
4000460116	142926	40,704	1/21/2022	2/3/2022	13	0.011%	0.0014
4000460258	26016	449	1/25/2022	2/7/2022	13	0.000%	0.0000
4000460238	126928	740	1/25/2022	2/7/2022	13	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460247	144581	1,208	1/25/2022	2/7/2022	13	0.000%	0.0000
4000460296	25599	622	1/26/2022	2/8/2022	13	0.000%	0.0000
4000460429	24885	700	1/27/2022	2/9/2022	13	0.000%	0.0000
4000460432	26639	9,315	1/27/2022	2/9/2022	13	0.002%	0.0003
4000460436	27068	404	1/27/2022	2/9/2022	13	0.000%	0.0000
4000460326	126369	50	1/27/2022	2/9/2022	13	0.000%	0.0000
4000460339	32952	32,331	1/27/2022	2/9/2022	13	0.009%	0.0011
4000460343	32959	2,294	1/27/2022	2/9/2022	13	0.001%	0.0001
4000460346	32987	12,723	1/27/2022	2/9/2022	13	0.003%	0.0004
4000460380	33102	20,121	1/27/2022	2/9/2022	13	0.005%	0.0007
4000460382	33104	81,353	1/27/2022	2/9/2022	13	0.021%	0.0028
4000460386	33112	178	1/27/2022	2/9/2022	13	0.000%	0.0000
4000460401	33129	1,668	1/27/2022	2/9/2022	13	0.000%	0.0001
4000460475	25716	1,995	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460476	26016	1,867	1/28/2022	2/10/2022	13	0.000%	0.0001
4000460477	27013	8,477	1/28/2022	2/10/2022	13	0.002%	0.0003
4000460481	30475	8,314	1/28/2022	2/10/2022	13	0.002%	0.0003
4000460482	32510	2,673	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460483	32853	2,520	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460562	33078	4,356	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460458	108149	96	1/28/2022	2/10/2022	13	0.000%	0.0000
4000460462	139503	501,102	1/28/2022	2/10/2022	13	0.132%	0.0172
4000460464	143340	1,272	1/28/2022	2/10/2022	13	0.000%	0.0000
4000460466	143477	1,799	1/28/2022	2/10/2022	13	0.000%	0.0001
4000460514	33095	727	1/28/2022	2/10/2022	13	0.000%	0.0000
4000460520	33103	5,909	1/28/2022	2/10/2022	13	0.002%	0.0002
4000460522	33106	2,825	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460524	33110	36,921	1/28/2022	2/10/2022	13	0.010%	0.0013
4000460527	33114	124,661	1/28/2022	2/10/2022	13	0.033%	0.0043
4000460539	33128	41,491	1/28/2022	2/10/2022	13	0.011%	0.0014
4000460545	33134	3,621	1/28/2022	2/10/2022	13	0.001%	0.0001
4000460552	33141	8,031	1/28/2022	2/10/2022	13	0.002%	0.0003
4000460666	24211	5,184	2/1/2022	2/14/2022	13	0.001%	0.0002
4000460621	25147	40,348	2/1/2022	2/14/2022	13	0.011%	0.0014
4000460638	141025	15,000	2/1/2022	2/14/2022	13	0.004%	0.0005
4000460651	142885	2,704	2/1/2022	2/14/2022	13	0.001%	0.0001
4000460742	11427	14,900	2/3/2022	2/16/2022	13	0.004%	0.0005
4000460749	26643	1,103	2/3/2022	2/16/2022	13	0.000%	0.0000
4000460759	32896	3,000	2/3/2022	2/16/2022	13	0.001%	0.0001
4000460790	11536	1,400	2/4/2022	2/17/2022	13	0.000%	0.0000
4000460784	144519	33,950	2/4/2022	2/17/2022	13	0.009%	0.0012
4000460906	24251	2,400	2/9/2022	2/22/2022	13	0.001%	0.0001
4000460919	34173	26,134	2/9/2022	2/22/2022	13	0.007%	0.0009
4000460894	142635	12,884	2/9/2022	2/22/2022	13	0.003%	0.0004
4000460899	144910	1,254	2/9/2022	2/22/2022	13	0.000%	0.0000
4000460953	8392	27,306	2/10/2022	2/23/2022	13	0.007%	0.0009
4000460971	33924	17,343	2/10/2022	2/23/2022	13	0.005%	0.0006
4000461038	30475	21,483	2/11/2022	2/24/2022	13	0.006%	0.0007
4000461039	30475	25,334	2/11/2022	2/24/2022	13	0.007%	0.0009
4000461041	33956	2,345	2/11/2022	2/24/2022	13	0.001%	0.0001
4000460985	9986	393,696	2/11/2022	2/24/2022	13	0.104%	0.0135
4000460986	15871	3,644	2/11/2022	2/24/2022	13	0.001%	0.0001
4000460995	103114	25	2/11/2022	2/24/2022	13	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460996	103639	208	2/11/2022	2/24/2022	13	0.000%	0.0000
4000460998	103913	71	2/11/2022	2/24/2022	13	0.000%	0.0000
4000461000	104509	5,739	2/11/2022	2/24/2022	13	0.002%	0.0002
4000461001	104872	632	2/11/2022	2/24/2022	13	0.000%	0.0000
4000461011	125951	52	2/11/2022	2/24/2022	13	0.000%	0.0000
4000461012	126719	2,204	2/11/2022	2/24/2022	13	0.001%	0.0001
4000461013	128425	1,017	2/11/2022	2/24/2022	13	0.000%	0.0000
4000461142	8392	7,592	2/16/2022	3/1/2022	13	0.002%	0.0003
4000461150	26643	3,762	2/16/2022	3/1/2022	13	0.001%	0.0001
4000461116	113710	1,000	2/16/2022	3/1/2022	13	0.000%	0.0000
4000461120	125949	1,000	2/16/2022	3/1/2022	13	0.000%	0.0000
4000461122	127106	1,000	2/16/2022	3/1/2022	13	0.000%	0.0000
4000461131	141101	29,587	2/16/2022	3/1/2022	13	0.008%	0.0010
4000461162	15871	3,958	2/17/2022	3/2/2022	13	0.001%	0.0001
4000461171	119139	125,000	2/17/2022	3/2/2022	13	0.033%	0.0043
4000461172	125783	1,170	2/17/2022	3/2/2022	13	0.000%	0.0000
4000461242	11372	471	2/18/2022	3/3/2022	13	0.000%	0.0000
4000461243	11426	4,303	2/18/2022	3/3/2022	13	0.001%	0.0001
4000461247	25708	1,817	2/18/2022	3/3/2022	13	0.000%	0.0001
4000461249	26643	4,607	2/18/2022	3/3/2022	13	0.001%	0.0002
4000461209	4502	6,237	2/18/2022	3/3/2022	13	0.002%	0.0002
4000461210	10439	440	2/18/2022	3/3/2022	13	0.000%	0.0000
4000461215	103676	1,479	2/18/2022	3/3/2022	13	0.000%	0.0001
4000461218	108083	36	2/18/2022	3/3/2022	13	0.000%	0.0000
4000461223	121825	11,428	2/18/2022	3/3/2022	13	0.003%	0.0004
4000461225	125742	27,200	2/18/2022	3/3/2022	13	0.007%	0.0009
4000461233	138494	3,080	2/18/2022	3/3/2022	13	0.001%	0.0001
4000461240	144760	769	2/18/2022	3/3/2022	13	0.000%	0.0000
4000461304	27704	1,650	2/22/2022	3/7/2022	13	0.000%	0.0001
4000461275	121800	10,000	2/22/2022	3/7/2022	13	0.003%	0.0003
4000461278	126928	257	2/22/2022	3/7/2022	13	0.000%	0.0000
4000461348	25808	2,400	2/23/2022	3/8/2022	13	0.001%	0.0001
4000461353	26356	336	2/23/2022	3/8/2022	13	0.000%	0.0000
4000461319	101853	3,957	2/23/2022	3/8/2022	13	0.001%	0.0001
4000461397	26643	5,094	2/24/2022	3/9/2022	13	0.001%	0.0002
4000461405	125016	4,437	2/24/2022	3/9/2022	13	0.001%	0.0002
4000461374	101853	10,619	2/24/2022	3/9/2022	13	0.003%	0.0004
4000461450	25809	839	2/25/2022	3/10/2022	13	0.000%	0.0000
4000461453	27982	4,470	2/25/2022	3/10/2022	13	0.001%	0.0002
4000461461	32875	300	2/25/2022	3/10/2022	13	0.000%	0.0000
4000461429	142587	3,096	2/25/2022	3/10/2022	13	0.001%	0.0001
4000461430	142885	133,840	2/25/2022	3/10/2022	13	0.035%	0.0046
4000461435	143991	16,960	2/25/2022	3/10/2022	13	0.004%	0.0006
4000461532	24251	2,460	3/1/2022	3/14/2022	13	0.001%	0.0001
4000461528	143477	73	3/1/2022	3/14/2022	13	0.000%	0.0000
4000461529	143520	2,065	3/1/2022	3/14/2022	13	0.001%	0.0001
4000461590	11474	10,525	3/2/2022	3/15/2022	13	0.003%	0.0004
4000461548	116850	431	3/2/2022	3/15/2022	13	0.000%	0.0000
4000461558	141021	2,700	3/2/2022	3/15/2022	13	0.001%	0.0001
4000461565	142002	7,696	3/2/2022	3/15/2022	13	0.002%	0.0003
4000461568	142587	1,754	3/2/2022	3/15/2022	13	0.000%	0.0001
4000461570	142874	2,293	3/2/2022	3/15/2022	13	0.001%	0.0001
4000461577	143520	2,045	3/2/2022	3/15/2022	13	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461581	144015	10,000	3/2/2022	3/15/2022	13	0.003%	0.0003
4000461587	144922	8,000	3/2/2022	3/15/2022	13	0.002%	0.0003
4000461629	30475	52,361	3/3/2022	3/16/2022	13	0.014%	0.0018
4000461607	26958	1,109	3/3/2022	3/16/2022	13	0.000%	0.0000
4000461618	144410	2,850	3/3/2022	3/16/2022	13	0.001%	0.0001
4000461620	144519	4,900	3/3/2022	3/16/2022	13	0.001%	0.0002
4000461603	101122	1,000	3/3/2022	3/16/2022	13	0.000%	0.0000
4000461660	25173	3,520	3/4/2022	3/17/2022	13	0.001%	0.0001
4000461663	28084	6,935	3/4/2022	3/17/2022	13	0.002%	0.0002
4000461665	30195	240	3/4/2022	3/17/2022	13	0.000%	0.0000
4000461668	32853	720	3/4/2022	3/17/2022	13	0.000%	0.0000
4000461634	10055	612	3/4/2022	3/17/2022	13	0.000%	0.0000
4000461712	104154	176	3/8/2022	3/21/2022	13	0.000%	0.0000
4000461806	124628	2,118	3/10/2022	3/23/2022	13	0.001%	0.0001
4000461773	131167	1,724	3/10/2022	3/23/2022	13	0.000%	0.0001
4000461838	11474	5,100	3/11/2022	3/24/2022	13	0.001%	0.0002
4000461816	101853	5,056	3/11/2022	3/24/2022	13	0.001%	0.0002
4000461897	8392	34,587	3/15/2022	3/28/2022	13	0.009%	0.0012
4000461917	30272	2,700	3/15/2022	3/28/2022	13	0.001%	0.0001
4000461918	32808	440	3/15/2022	3/28/2022	13	0.000%	0.0000
4000461884	105195	906	3/15/2022	3/28/2022	13	0.000%	0.0000
4000461886	124628	19,633	3/15/2022	3/28/2022	13	0.005%	0.0007
4000461889	126912	1,641	3/15/2022	3/28/2022	13	0.000%	0.0001
4000461988	14463	13,894	3/17/2022	3/30/2022	13	0.004%	0.0005
4000461990	26643	13,536	3/17/2022	3/30/2022	13	0.004%	0.0005
4000461962	24114	734	3/17/2022	3/30/2022	13	0.000%	0.0000
4000462019	126928	56	3/18/2022	3/31/2022	13	0.000%	0.0000
4000462131	11372	1,273	3/22/2022	4/4/2022	13	0.000%	0.0000
4000462135	34173	29,084	3/22/2022	4/4/2022	13	0.008%	0.0010
4000462117	9145	9,050	3/22/2022	4/4/2022	13	0.002%	0.0003
4000462119	117183	841	3/22/2022	4/4/2022	13	0.000%	0.0000
4000462122	126928	221	3/22/2022	4/4/2022	13	0.000%	0.0000
4000462127	143727	85,536	3/22/2022	4/4/2022	13	0.023%	0.0029
4000462185	8392	20,129	3/24/2022	4/6/2022	13	0.005%	0.0007
4000462192	32897	1,800	3/24/2022	4/6/2022	13	0.000%	0.0001
4000462196	135537	4,284	3/24/2022	4/6/2022	13	0.001%	0.0001
4000462173	116902	13,700	3/24/2022	4/6/2022	13	0.004%	0.0005
4000462231	26639	1,350	3/25/2022	4/7/2022	13	0.000%	0.0000
4000462203	27636	400	3/25/2022	4/7/2022	13	0.000%	0.0000
4000462216	142926	9,527	3/25/2022	4/7/2022	13	0.003%	0.0003
4000462299	11304	5,100	3/29/2022	4/11/2022	13	0.001%	0.0002
4000462312	27389	20,700	3/29/2022	4/11/2022	13	0.005%	0.0007
4000462291	124628	26,925	3/29/2022	4/11/2022	13	0.007%	0.0009
4000462316	33097	79,724	3/29/2022	4/11/2022	13	0.021%	0.0027
4000462347	129898	4,500	3/30/2022	4/12/2022	13	0.001%	0.0002
4000462350	133309	820	3/30/2022	4/12/2022	13	0.000%	0.0000
4000462370	144290	750	3/30/2022	4/12/2022	13	0.000%	0.0000
4000462317	107932	95	3/30/2022	4/12/2022	13	0.000%	0.0000
4000462318	107932	65	3/30/2022	4/12/2022	13	0.000%	0.0000
4000462435	11427	11,100	3/31/2022	4/13/2022	13	0.003%	0.0004
4000462465	130375	28,122	3/31/2022	4/13/2022	13	0.007%	0.0010
4000462415	124628	5,792	3/31/2022	4/13/2022	13	0.002%	0.0002
4000462519	9673	925	4/1/2022	4/14/2022	13	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462532	26643	7,682	4/1/2022	4/14/2022	13	0.002%	0.0003
4000462533	27013	1,992	4/1/2022	4/14/2022	13	0.001%	0.0001
4000462534	29469	1,610	4/1/2022	4/14/2022	13	0.000%	0.0001
4000462541	33924	813	4/1/2022	4/14/2022	13	0.000%	0.0000
4000462493	126369	641	4/1/2022	4/14/2022	13	0.000%	0.0000
4000462494	128197	100	4/1/2022	4/14/2022	13	0.000%	0.0000
4000462497	139275	268	4/1/2022	4/14/2022	13	0.000%	0.0000
4000462505	142942	3,988	4/1/2022	4/14/2022	13	0.001%	0.0001
4000462511	144270	47,148	4/1/2022	4/14/2022	13	0.012%	0.0016
4000462467	102473	650	4/1/2022	4/14/2022	13	0.000%	0.0000
4000462633	11372	882	4/6/2022	4/19/2022	13	0.000%	0.0000
4000462643	126165	746	4/6/2022	4/19/2022	13	0.000%	0.0000
4000462618	103471	668	4/6/2022	4/19/2022	13	0.000%	0.0000
4000462626	139503	94,736	4/6/2022	4/19/2022	13	0.025%	0.0032
4000462630	144344	40,000	4/6/2022	4/19/2022	13	0.011%	0.0014
4000462667	144540	25,230	4/7/2022	4/20/2022	13	0.007%	0.0009
4000462726	9121	900	4/8/2022	4/21/2022	13	0.000%	0.0000
4000462732	27962	1,824	4/8/2022	4/21/2022	13	0.000%	0.0001
4000462739	33924	105	4/8/2022	4/21/2022	13	0.000%	0.0000
4000462702	132427	11,651	4/8/2022	4/21/2022	13	0.003%	0.0004
4000462793	23681	4,775	4/12/2022	4/25/2022	13	0.001%	0.0002
4000462796	26643	19,651	4/12/2022	4/25/2022	13	0.005%	0.0007
4000462786	142942	1,205	4/12/2022	4/25/2022	13	0.000%	0.0000
4000462789	144530	12,181	4/12/2022	4/25/2022	13	0.003%	0.0004
4000462806	105459	1,980	4/13/2022	4/26/2022	13	0.001%	0.0001
4000462814	116845	5,000	4/13/2022	4/26/2022	13	0.001%	0.0002
4000462820	124788	1,500	4/13/2022	4/26/2022	13	0.000%	0.0001
4000462870	34888	435	4/14/2022	4/27/2022	13	0.000%	0.0000
4000462977	9121	1,800	4/19/2022	5/2/2022	13	0.000%	0.0001
4000462975	142942	6,705	4/19/2022	5/2/2022	13	0.002%	0.0002
4000463014	8392	12,145	4/20/2022	5/3/2022	13	0.003%	0.0004
4000463019	23681	2,122	4/20/2022	5/3/2022	13	0.001%	0.0001
4000463026	106699	6,919	4/20/2022	5/3/2022	13	0.002%	0.0002
4000463062	26604	1,215	4/21/2022	5/4/2022	13	0.000%	0.0000
4000463114	11372	3,652	4/22/2022	5/5/2022	13	0.001%	0.0001
4000463122	27162	1,725	4/22/2022	5/5/2022	13	0.000%	0.0001
4000463125	28737	550	4/22/2022	5/5/2022	13	0.000%	0.0000
4000463085	102504	95	4/22/2022	5/5/2022	13	0.000%	0.0000
4000463087	104872	49	4/22/2022	5/5/2022	13	0.000%	0.0000
4000463093	126928	245	4/22/2022	5/5/2022	13	0.000%	0.0000
4000463098	141583	129	4/22/2022	5/5/2022	13	0.000%	0.0000
4000463100	142926	34,072	4/22/2022	5/5/2022	13	0.009%	0.0012
4000463108	144270	72,821	4/22/2022	5/5/2022	13	0.019%	0.0025
4000463192	8392	12,754	4/26/2022	5/9/2022	13	0.003%	0.0004
4000463195	25379	2,948	4/26/2022	5/9/2022	13	0.001%	0.0001
4000463197	26643	5,493	4/26/2022	5/9/2022	13	0.001%	0.0002
4000463200	28084	45,885	4/26/2022	5/9/2022	13	0.012%	0.0016
4000463181	24856	370	4/26/2022	5/9/2022	13	0.000%	0.0000
4000463238	25987	3,700	4/27/2022	5/10/2022	13	0.001%	0.0001
4000463384	27994	10,010	4/29/2022	5/12/2022	13	0.003%	0.0003
4000463333	108498	21,336	4/29/2022	5/12/2022	13	0.006%	0.0007
4000463348	142870	22,283	4/29/2022	5/12/2022	13	0.006%	0.0008
4000463511	26674	1,960	5/3/2022	5/16/2022	13	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463476	141831	11,647	5/3/2022	5/16/2022	13	0.003%	0.0004
4000463488	143929	22,666	5/3/2022	5/16/2022	13	0.006%	0.0008
4000463495	144573	4,000	5/3/2022	5/16/2022	13	0.001%	0.0001
4000463614	29469	1,093	5/6/2022	5/19/2022	13	0.000%	0.0000
4000463579	25147	159,296	5/6/2022	5/19/2022	13	0.042%	0.0055
4000463674	26588	15,515	5/10/2022	5/23/2022	13	0.004%	0.0005
4000463686	135537	648	5/10/2022	5/23/2022	13	0.000%	0.0000
4000463721	26644	1,080	5/11/2022	5/24/2022	13	0.000%	0.0000
4000463700	141423	6,400	5/11/2022	5/24/2022	13	0.002%	0.0002
4000463701	142942	644	5/11/2022	5/24/2022	13	0.000%	0.0000
4000463739	26453	1,200	5/12/2022	5/25/2022	13	0.000%	0.0000
4000463791	9673	1,450	5/13/2022	5/26/2022	13	0.000%	0.0000
4000463799	25908	12,938	5/13/2022	5/26/2022	13	0.003%	0.0004
4000463803	27704	3,500	5/13/2022	5/26/2022	13	0.001%	0.0001
4000463806	30475	35,209	5/13/2022	5/26/2022	13	0.009%	0.0012
4000463807	30475	37,890	5/13/2022	5/26/2022	13	0.010%	0.0013
4000463808	30475	40,192	5/13/2022	5/26/2022	13	0.011%	0.0014
4000463809	30475	42,835	5/13/2022	5/26/2022	13	0.011%	0.0015
4000463810	30475	44,281	5/13/2022	5/26/2022	13	0.012%	0.0015
4000463811	30475	30,588	5/13/2022	5/26/2022	13	0.008%	0.0010
4000463812	30475	32,436	5/13/2022	5/26/2022	13	0.009%	0.0011
4000463815	32537	1,540	5/13/2022	5/26/2022	13	0.000%	0.0001
4000463760	29254	3,099	5/13/2022	5/26/2022	13	0.001%	0.0001
4000463779	141346	134,310	5/13/2022	5/26/2022	13	0.035%	0.0046
4000463972	124943	1,948	5/18/2022	5/31/2022	13	0.001%	0.0001
4000463930	103639	212	5/18/2022	5/31/2022	13	0.000%	0.0000
4000463932	104872	42	5/18/2022	5/31/2022	13	0.000%	0.0000
4000464004	27013	140	5/19/2022	6/1/2022	13	0.000%	0.0000
4000464010	33770	32,604	5/19/2022	6/1/2022	13	0.009%	0.0011
4000464047	23681	2,122	5/20/2022	6/2/2022	13	0.001%	0.0001
4000464050	27013	57,828	5/20/2022	6/2/2022	13	0.015%	0.0020
4000464017	27094	72,197	5/20/2022	6/2/2022	13	0.019%	0.0025
4000464020	103008	556	5/20/2022	6/2/2022	13	0.000%	0.0000
4000464112	11372	882	5/24/2022	6/6/2022	13	0.000%	0.0000
4000464123	27482	2,205	5/24/2022	6/6/2022	13	0.001%	0.0001
4000464099	108289	277	5/24/2022	6/6/2022	13	0.000%	0.0000
4000464104	141583	100	5/24/2022	6/6/2022	13	0.000%	0.0000
4000464171	26668	9,700	5/25/2022	6/7/2022	13	0.003%	0.0003
4000464180	117331	16,250	5/25/2022	6/7/2022	13	0.004%	0.0006
4000464181	126165	918	5/25/2022	6/7/2022	13	0.000%	0.0000
4000464140	104872	2,764	5/25/2022	6/7/2022	13	0.001%	0.0001
4000464225	28619	6,255	5/26/2022	6/8/2022	13	0.002%	0.0002
4000464230	32356	1,733	5/26/2022	6/8/2022	13	0.000%	0.0001
4000464233	124628	2,168	5/26/2022	6/8/2022	13	0.001%	0.0001
4000464304	106699	22,163	5/27/2022	6/9/2022	13	0.006%	0.0008
4000464245	22798	11,691	5/27/2022	6/9/2022	13	0.003%	0.0004
4000464246	22798	60,347	5/27/2022	6/9/2022	13	0.016%	0.0021
4000464250	34888	54	5/27/2022	6/9/2022	13	0.000%	0.0000
4000464289	145106	27,500	5/27/2022	6/9/2022	13	0.007%	0.0009
4000464341	8392	2,664	5/31/2022	6/13/2022	13	0.001%	0.0001
4000464358	26604	6,765	5/31/2022	6/13/2022	13	0.002%	0.0002
4000464362	26655	2,539	5/31/2022	6/13/2022	13	0.001%	0.0001
4000464364	28619	13,794	5/31/2022	6/13/2022	13	0.004%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464365	28737	2,650	5/31/2022	6/13/2022	13	0.001%	0.0001
4000464368	138068	22,759	5/31/2022	6/13/2022	13	0.006%	0.0008
4000464315	104872	109	5/31/2022	6/13/2022	13	0.000%	0.0000
4000464318	108021	500	5/31/2022	6/13/2022	13	0.000%	0.0000
4000464320	112048	1,000	5/31/2022	6/13/2022	13	0.000%	0.0000
4000464327	129896	1,000	5/31/2022	6/13/2022	13	0.000%	0.0000
4000464330	138305	2,500	5/31/2022	6/13/2022	13	0.001%	0.0001
4000464406	26644	38,408	6/1/2022	6/14/2022	13	0.010%	0.0013
4000464481	34173	621	6/2/2022	6/15/2022	13	0.000%	0.0000
4000464416	6396	26,762	6/2/2022	6/15/2022	13	0.007%	0.0009
4000464443	142002	7,696	6/2/2022	6/15/2022	13	0.002%	0.0003
4000464452	143400	3,000	6/2/2022	6/15/2022	13	0.001%	0.0001
4000464536	33770	16,740	6/3/2022	6/16/2022	13	0.004%	0.0006
4000464514	143520	2,296	6/3/2022	6/16/2022	13	0.001%	0.0001
4000464665	17342	8,505	6/9/2022	6/22/2022	13	0.002%	0.0003
4000464717	9121	500	6/10/2022	6/23/2022	13	0.000%	0.0000
4000464722	24259	1,285	6/10/2022	6/23/2022	13	0.000%	0.0000
4000464729	30475	52,522	6/10/2022	6/23/2022	13	0.014%	0.0018
4000464730	30475	60,830	6/10/2022	6/23/2022	13	0.016%	0.0021
4000464731	30475	34,619	6/10/2022	6/23/2022	13	0.009%	0.0012
4000464732	30475	44,034	6/10/2022	6/23/2022	13	0.012%	0.0015
4000464688	30494	8,550	6/10/2022	6/23/2022	13	0.002%	0.0003
4000464691	103471	158	6/10/2022	6/23/2022	13	0.000%	0.0000
4000464692	104872	182	6/10/2022	6/23/2022	13	0.000%	0.0000
4000464681	114658	101,505	6/10/2022	6/23/2022	13	0.027%	0.0035
4000464815	32356	816	6/14/2022	6/27/2022	13	0.000%	0.0000
4000464788	24114	660	6/14/2022	6/27/2022	13	0.000%	0.0000
4000464800	142942	9,178	6/14/2022	6/27/2022	13	0.002%	0.0003
4000464801	143072	14,213	6/14/2022	6/27/2022	13	0.004%	0.0005
4000464849	26490	5,412	6/15/2022	6/28/2022	13	0.001%	0.0002
4000464823	104872	224	6/15/2022	6/28/2022	13	0.000%	0.0000
4000464938	11054	6,048	6/17/2022	6/30/2022	13	0.002%	0.0002
4000464940	11372	1,764	6/17/2022	6/30/2022	13	0.000%	0.0001
4000464941	11474	4,200	6/17/2022	6/30/2022	13	0.001%	0.0001
4000464952	27013	1,856	6/17/2022	6/30/2022	13	0.000%	0.0001
4000464955	28530	17,093	6/17/2022	6/30/2022	13	0.005%	0.0006
4000464964	32099	1,660	6/17/2022	6/30/2022	13	0.000%	0.0001
4000464965	32897	1,000	6/17/2022	6/30/2022	13	0.000%	0.0000
4000464966	33770	175,430	6/17/2022	6/30/2022	13	0.046%	0.0060
4000464900	11260	1,273	6/17/2022	6/30/2022	13	0.000%	0.0000
4000464915	126928	54	6/17/2022	6/30/2022	13	0.000%	0.0000
4000464921	142885	3,550	6/17/2022	6/30/2022	13	0.001%	0.0001
4000464925	143477	1,335	6/17/2022	6/30/2022	13	0.000%	0.0000
4000464932	144955	1,130	6/17/2022	6/30/2022	13	0.000%	0.0000
4000465037	13911	57,213	6/22/2022	7/5/2022	13	0.015%	0.0020
4000465049	32808	2,860	6/22/2022	7/5/2022	13	0.001%	0.0001
4000465069	119251	20,670	6/23/2022	7/6/2022	13	0.005%	0.0007
4000465071	123377	26,039	6/23/2022	7/6/2022	13	0.007%	0.0009
4000465145	11304	1,200	6/24/2022	7/7/2022	13	0.000%	0.0000
4000465146	11372	471	6/24/2022	7/7/2022	13	0.000%	0.0000
4000465148	13911	3,905	6/24/2022	7/7/2022	13	0.001%	0.0001
4000465159	27013	270	6/24/2022	7/7/2022	13	0.000%	0.0000
4000465160	27361	140,164	6/24/2022	7/7/2022	13	0.037%	0.0048

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465162	28530	25,562	6/24/2022	7/7/2022	13	0.007%	0.0009
4000465130	142926	16,467	6/24/2022	7/7/2022	13	0.004%	0.0006
4000465142	145093	2,398	6/24/2022	7/7/2022	13	0.001%	0.0001
4000465143	145137	1,700	6/24/2022	7/7/2022	13	0.000%	0.0001
4000465256	13911	47,520	6/28/2022	7/11/2022	13	0.013%	0.0016
4000465264	26639	1,890	6/28/2022	7/11/2022	13	0.000%	0.0001
4000465239	108289	284	6/28/2022	7/11/2022	13	0.000%	0.0000
4000465252	145141	277	6/28/2022	7/11/2022	13	0.000%	0.0000
4000465279	132321	103	6/29/2022	7/12/2022	13	0.000%	0.0000
4000465366	26299	1,321	6/30/2022	7/13/2022	13	0.000%	0.0000
4000465367	26588	15,150	6/30/2022	7/13/2022	13	0.004%	0.0005
4000465302	103301	197	6/30/2022	7/13/2022	13	0.000%	0.0000
4000465303	104473	74,650	6/30/2022	7/13/2022	13	0.020%	0.0026
4000465305	104579	231,555	6/30/2022	7/13/2022	13	0.061%	0.0079
4000465317	137757	2,935	6/30/2022	7/13/2022	13	0.001%	0.0001
4000465356	145152	8,240	6/30/2022	7/13/2022	13	0.002%	0.0003
4000465427	11260	3,289	7/1/2022	7/14/2022	13	0.001%	0.0001
4000465428	11426	3,834	7/1/2022	7/14/2022	13	0.001%	0.0001
4000465430	18267	26,159	7/1/2022	7/14/2022	13	0.007%	0.0009
4000465433	24259	2,488	7/1/2022	7/14/2022	13	0.001%	0.0001
4000465438	25938	6,594	7/1/2022	7/14/2022	13	0.002%	0.0002
4000465441	26297	8,078	7/1/2022	7/14/2022	13	0.002%	0.0003
4000465444	26363	4,076	7/1/2022	7/14/2022	13	0.001%	0.0001
4000465446	26604	10,955	7/1/2022	7/14/2022	13	0.003%	0.0004
4000465448	27013	11,857	7/1/2022	7/14/2022	13	0.003%	0.0004
4000465455	30475	37,673	7/1/2022	7/14/2022	13	0.010%	0.0013
4000465456	30475	44,083	7/1/2022	7/14/2022	13	0.012%	0.0015
4000465457	30475	33,222	7/1/2022	7/14/2022	13	0.009%	0.0011
4000465460	32808	660	7/1/2022	7/14/2022	13	0.000%	0.0000
4000465385	25147	212,439	7/1/2022	7/14/2022	13	0.056%	0.0073
4000465393	101853	4,746	7/1/2022	7/14/2022	13	0.001%	0.0002
4000465396	105195	8,624	7/1/2022	7/14/2022	13	0.002%	0.0003
4000465409	139487	760	7/1/2022	7/14/2022	13	0.000%	0.0000
4000465424	145067	2,200	7/1/2022	7/14/2022	13	0.001%	0.0001
4000465426	145194	6,000	7/1/2022	7/14/2022	13	0.002%	0.0002
4000465469	6396	500	7/5/2022	7/18/2022	13	0.000%	0.0000
4000465481	145059	2,000	7/5/2022	7/18/2022	13	0.001%	0.0001
4000465524	30475	1,857	7/6/2022	7/19/2022	13	0.000%	0.0001
4000465610	26493	261	7/8/2022	7/21/2022	13	0.000%	0.0000
4000465612	26639	4,995	7/8/2022	7/21/2022	13	0.001%	0.0002
4000465614	26643	2,165	7/8/2022	7/21/2022	13	0.001%	0.0001
4000465618	27994	3,410	7/8/2022	7/21/2022	13	0.001%	0.0001
4000465740	102504	99	7/13/2022	7/26/2022	13	0.000%	0.0000
4000465804	30475	6,318	7/14/2022	7/27/2022	13	0.002%	0.0002
4000465787	142942	341	7/14/2022	7/27/2022	13	0.000%	0.0000
4000465843	11426	2,368	7/15/2022	7/28/2022	13	0.001%	0.0001
4000465850	30475	87,435	7/15/2022	7/28/2022	13	0.023%	0.0030
4000465851	30475	69,767	7/15/2022	7/28/2022	13	0.018%	0.0024
4000465852	30475	71,801	7/15/2022	7/28/2022	13	0.019%	0.0025
4000465853	30475	73,619	7/15/2022	7/28/2022	13	0.019%	0.0025
4000465854	30475	75,509	7/15/2022	7/28/2022	13	0.020%	0.0026
4000465855	30475	77,970	7/15/2022	7/28/2022	13	0.021%	0.0027
4000465856	30475	78,989	7/15/2022	7/28/2022	13	0.021%	0.0027

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465857	30475	81,875	7/15/2022	7/28/2022	13	0.022%	0.0028
4000465858	30475	84,058	7/15/2022	7/28/2022	13	0.022%	0.0029
4000465865	106699	10,731	7/15/2022	7/28/2022	13	0.003%	0.0004
4000465816	15871	2,648	7/15/2022	7/28/2022	13	0.001%	0.0001
4000465836	144247	189,170	7/15/2022	7/28/2022	13	0.050%	0.0065
4000465893	124628	24,733	7/19/2022	8/1/2022	13	0.007%	0.0008
4000465920	32973	263	7/19/2022	8/1/2022	13	0.000%	0.0000
4000465921	32979	7,877	7/19/2022	8/1/2022	13	0.002%	0.0003
4000465925	33021	103,609	7/19/2022	8/1/2022	13	0.027%	0.0036
4000465931	33064	33,270	7/19/2022	8/1/2022	13	0.009%	0.0011
4000465932	33072	57,863	7/19/2022	8/1/2022	13	0.015%	0.0020
4000465939	33146	10,012	7/19/2022	8/1/2022	13	0.003%	0.0003
4000465965	145247	5,000	7/20/2022	8/2/2022	13	0.001%	0.0002
4000466005	13911	5,885	7/21/2022	8/3/2022	13	0.002%	0.0002
4000466009	25808	480	7/21/2022	8/3/2022	13	0.000%	0.0000
4000465992	126715	21,000	7/21/2022	8/3/2022	13	0.006%	0.0007
4000466052	9673	11,450	7/22/2022	8/4/2022	13	0.003%	0.0004
4000466062	25131	1,663	7/22/2022	8/4/2022	13	0.000%	0.0001
4000466063	25272	14,958	7/22/2022	8/4/2022	13	0.004%	0.0005
4000466065	26356	298	7/22/2022	8/4/2022	13	0.000%	0.0000
4000466074	30475	82,125	7/22/2022	8/4/2022	13	0.022%	0.0028
4000466076	30475	73,710	7/22/2022	8/4/2022	13	0.019%	0.0025
4000466077	30475	76,273	7/22/2022	8/4/2022	13	0.020%	0.0026
4000466039	142885	3,846	7/22/2022	8/4/2022	13	0.001%	0.0001
4000466040	142926	45,116	7/22/2022	8/4/2022	13	0.012%	0.0015
4000466158	9891	4,251	7/26/2022	8/8/2022	13	0.001%	0.0001
4000466118	135057	2,533	7/26/2022	8/8/2022	13	0.001%	0.0001
4000466133	143364	12,300	7/26/2022	8/8/2022	13	0.003%	0.0004
4000466134	143400	3,000	7/26/2022	8/8/2022	13	0.001%	0.0001
4000466144	144519	8,677	7/26/2022	8/8/2022	13	0.002%	0.0003
4000466156	145245	26,679	7/26/2022	8/8/2022	13	0.007%	0.0009
4000466184	8392	30,862	7/27/2022	8/9/2022	13	0.008%	0.0011
4000466190	25808	17,580	7/27/2022	8/9/2022	13	0.005%	0.0006
4000466197	106699	4,717	7/27/2022	8/9/2022	13	0.001%	0.0002
4000466167	27466	2,851	7/27/2022	8/9/2022	13	0.001%	0.0001
4000466169	105195	1,510	7/27/2022	8/9/2022	13	0.000%	0.0001
4000466243	30475	56,984	7/28/2022	8/10/2022	13	0.015%	0.0020
4000466226	145222	874	7/28/2022	8/10/2022	13	0.000%	0.0000
4000466296	24765	8,070	7/29/2022	8/11/2022	13	0.002%	0.0003
4000466298	25659	26,810	7/29/2022	8/11/2022	13	0.007%	0.0009
4000466299	25809	1,713	7/29/2022	8/11/2022	13	0.000%	0.0001
4000466301	26356	667	7/29/2022	8/11/2022	13	0.000%	0.0000
4000466302	26362	1,500	7/29/2022	8/11/2022	13	0.000%	0.0001
4000466309	27013	26,067	7/29/2022	8/11/2022	13	0.007%	0.0009
4000466315	28084	12,920	7/29/2022	8/11/2022	13	0.003%	0.0004
4000466317	28737	13,350	7/29/2022	8/11/2022	13	0.004%	0.0005
4000466318	30475	48,024	7/29/2022	8/11/2022	13	0.013%	0.0016
4000466319	30475	49,985	7/29/2022	8/11/2022	13	0.013%	0.0017
4000466320	30475	53,492	7/29/2022	8/11/2022	13	0.014%	0.0018
4000466321	30475	55,242	7/29/2022	8/11/2022	13	0.015%	0.0019
4000466322	30475	60,019	7/29/2022	8/11/2022	13	0.016%	0.0021
4000466323	30475	61,935	7/29/2022	8/11/2022	13	0.016%	0.0021
4000466324	30475	65,332	7/29/2022	8/11/2022	13	0.017%	0.0022

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466325	30475	69,053	7/29/2022	8/11/2022	13	0.018%	0.0024
4000466341	130375	23,971	7/29/2022	8/11/2022	13	0.006%	0.0008
4000466342	134272	58,628	7/29/2022	8/11/2022	13	0.015%	0.0020
4000466257	9673	3,700	7/29/2022	8/11/2022	13	0.001%	0.0001
4000466260	22798	53,721	7/29/2022	8/11/2022	13	0.014%	0.0018
4000466261	22798	134,476	7/29/2022	8/11/2022	13	0.035%	0.0046
4000466266	33624	12,284	7/29/2022	8/11/2022	13	0.003%	0.0004
4000466277	137757	50,168	7/29/2022	8/11/2022	13	0.013%	0.0017
4000466279	142615	29,568	7/29/2022	8/11/2022	13	0.008%	0.0010
4000466283	143892	1,200	7/29/2022	8/11/2022	13	0.000%	0.0000
4000466474	105195	592	8/3/2022	8/16/2022	13	0.000%	0.0000
4000466441	30494	87	8/3/2022	8/16/2022	13	0.000%	0.0000
4000466458	141583	129	8/3/2022	8/16/2022	13	0.000%	0.0000
4000466520	30475	1,208	8/4/2022	8/17/2022	13	0.000%	0.0000
4000466522	33203	633	8/4/2022	8/17/2022	13	0.000%	0.0000
4000466494	101853	1,160	8/4/2022	8/17/2022	13	0.000%	0.0000
4000466503	142942	1,695	8/4/2022	8/17/2022	13	0.000%	0.0001
4000466566	25808	1,440	8/5/2022	8/18/2022	13	0.000%	0.0000
4000466569	27013	2,084	8/5/2022	8/18/2022	13	0.001%	0.0001
4000466579	130375	24,257	8/5/2022	8/18/2022	13	0.006%	0.0008
4000466528	7214	461,723	8/5/2022	8/18/2022	13	0.122%	0.0158
4000466530	15871	817	8/5/2022	8/18/2022	13	0.000%	0.0000
4000466532	103392	34	8/5/2022	8/18/2022	13	0.000%	0.0000
4000466538	125951	53	8/5/2022	8/18/2022	13	0.000%	0.0000
4000466540	135488	2,760	8/5/2022	8/18/2022	13	0.001%	0.0001
4000466544	142681	97,264	8/5/2022	8/18/2022	13	0.026%	0.0033
4000466559	144519	5,000	8/5/2022	8/18/2022	13	0.001%	0.0002
4000466646	101853	788	8/10/2022	8/23/2022	13	0.000%	0.0000
4000466650	111078	1,000	8/10/2022	8/23/2022	13	0.000%	0.0000
4000466664	138371	500	8/10/2022	8/23/2022	13	0.000%	0.0000
4000466670	143072	2,233	8/10/2022	8/23/2022	13	0.001%	0.0001
4000466699	33053	19,473	8/10/2022	8/23/2022	13	0.005%	0.0007
4000466750	11577	2,153	8/11/2022	8/24/2022	13	0.001%	0.0001
4000466756	24383	1,153	8/11/2022	8/24/2022	13	0.000%	0.0000
4000466766	34173	3,105	8/11/2022	8/24/2022	13	0.001%	0.0001
4000466726	15871	13,792	8/11/2022	8/24/2022	13	0.004%	0.0005
4000466737	142162	11,000	8/11/2022	8/24/2022	13	0.003%	0.0004
4000466808	30475	63,077	8/12/2022	8/25/2022	13	0.017%	0.0022
4000466809	30475	68,733	8/12/2022	8/25/2022	13	0.018%	0.0024
4000466810	30475	52,738	8/12/2022	8/25/2022	13	0.014%	0.0018
4000466811	30475	56,428	8/12/2022	8/25/2022	13	0.015%	0.0019
4000466775	101853	12,854	8/12/2022	8/25/2022	13	0.003%	0.0004
4000466898	126165	7,003	8/16/2022	8/29/2022	13	0.002%	0.0002
4000466861	101853	23,162	8/16/2022	8/29/2022	13	0.006%	0.0008
4000466880	142885	3,604	8/16/2022	8/29/2022	13	0.001%	0.0001
4000466881	142942	6,280	8/16/2022	8/29/2022	13	0.002%	0.0002
4000466883	144581	4,591	8/16/2022	8/29/2022	13	0.001%	0.0002
4000466855	114658	19,800	8/16/2022	8/29/2022	13	0.005%	0.0007
4000466856	114658	7,500	8/16/2022	8/29/2022	13	0.002%	0.0003
4000466857	118029	32,373	8/16/2022	8/29/2022	13	0.009%	0.0011
4000466925	25708	1,470	8/17/2022	8/30/2022	13	0.000%	0.0001
4000466903	105195	1,510	8/17/2022	8/30/2022	13	0.000%	0.0001
4000466910	134862	132,683	8/17/2022	8/30/2022	13	0.035%	0.0045

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466911	135488	6,252	8/17/2022	8/30/2022	13	0.002%	0.0002
4000466915	143189	63,791	8/17/2022	8/30/2022	13	0.017%	0.0022
4000466946	101853	49,456	8/18/2022	8/31/2022	13	0.013%	0.0017
4000467011	11427	10,100	8/19/2022	9/1/2022	13	0.003%	0.0003
4000467023	28530	6,622	8/19/2022	9/1/2022	13	0.002%	0.0002
4000466980	103008	1,641	8/19/2022	9/1/2022	13	0.000%	0.0001
4000466983	104872	22	8/19/2022	9/1/2022	13	0.000%	0.0000
4000466986	112103	8,306	8/19/2022	9/1/2022	13	0.002%	0.0003
4000467036	32951	22,920	8/19/2022	9/1/2022	13	0.006%	0.0008
4000467045	33005	1,777	8/19/2022	9/1/2022	13	0.000%	0.0001
4000467140	28619	12,910	8/24/2022	9/6/2022	13	0.003%	0.0004
4000467109	6031	6,378	8/24/2022	9/6/2022	13	0.002%	0.0002
4000467112	34888	25	8/24/2022	9/6/2022	13	0.000%	0.0000
4000467115	103603	2,218	8/24/2022	9/6/2022	13	0.001%	0.0001
4000467133	145265	1,000	8/24/2022	9/6/2022	13	0.000%	0.0000
4000467177	8392	74,394	8/25/2022	9/7/2022	13	0.020%	0.0026
4000467194	34341	6,600	8/25/2022	9/7/2022	13	0.002%	0.0002
4000467232	10384	6,300	8/26/2022	9/8/2022	13	0.002%	0.0002
4000467200	15871	4,733	8/26/2022	9/8/2022	13	0.001%	0.0002
4000467204	34888	2,054	8/26/2022	9/8/2022	13	0.001%	0.0001
4000467257	33067	93,109	8/26/2022	9/8/2022	13	0.025%	0.0032
4000467324	26644	33,953	8/30/2022	9/12/2022	13	0.009%	0.0012
4000467325	27704	11,350	8/30/2022	9/12/2022	13	0.003%	0.0004
4000467310	144097	203,954	8/30/2022	9/12/2022	13	0.054%	0.0070
4000467332	33079	4,513	8/30/2022	9/12/2022	13	0.001%	0.0002
4000467385	30475	20,188	8/31/2022	9/13/2022	13	0.005%	0.0007
4000467359	138747	110	8/31/2022	9/13/2022	13	0.000%	0.0000
4000467422	8392	72,577	9/1/2022	9/14/2022	13	0.019%	0.0025
4000467437	27068	798	9/1/2022	9/14/2022	13	0.000%	0.0000
4000467397	22798	47,588	9/1/2022	9/14/2022	13	0.013%	0.0016
4000467420	145164	11,866	9/1/2022	9/14/2022	13	0.003%	0.0004
4000467518	25708	774	9/2/2022	9/15/2022	13	0.000%	0.0000
4000467522	26674	6,300	9/2/2022	9/15/2022	13	0.002%	0.0002
4000467454	10384	1,000	9/2/2022	9/15/2022	13	0.000%	0.0000
4000467494	143807	1,058	9/2/2022	9/15/2022	13	0.000%	0.0000
4000467496	143929	52,458	9/2/2022	9/15/2022	13	0.014%	0.0018
4000467561	28619	10,120	9/6/2022	9/19/2022	13	0.003%	0.0003
4000467549	142885	2,966	9/6/2022	9/19/2022	13	0.001%	0.0001
4000467581	30475	28,287	9/7/2022	9/20/2022	13	0.007%	0.0010
4000467566	103603	4,635	9/7/2022	9/20/2022	13	0.001%	0.0002
4000467611	11304	900	9/8/2022	9/21/2022	13	0.000%	0.0000
4000467613	20063	5,687	9/8/2022	9/21/2022	13	0.001%	0.0002
4000467589	6396	17,842	9/8/2022	9/21/2022	13	0.005%	0.0006
4000467654	11372	24,593	9/9/2022	9/22/2022	13	0.006%	0.0008
4000467659	28530	22,072	9/9/2022	9/22/2022	13	0.006%	0.0008
4000467629	126928	246	9/9/2022	9/22/2022	13	0.000%	0.0000
4000467703	24114	1,650	9/13/2022	9/26/2022	13	0.000%	0.0001
4000467711	125016	3,406	9/13/2022	9/26/2022	13	0.001%	0.0001
4000467713	135537	25,268	9/13/2022	9/26/2022	13	0.007%	0.0009
4000467759	26490	925	9/14/2022	9/27/2022	13	0.000%	0.0000
4000467765	30475	51,185	9/14/2022	9/27/2022	13	0.014%	0.0018
4000467766	30475	37,729	9/14/2022	9/27/2022	13	0.010%	0.0013
4000467735	142942	1,471	9/14/2022	9/27/2022	13	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467740	144581	7,490	9/14/2022	9/27/2022	13	0.002%	0.0003
4000467780	34888	20	9/15/2022	9/28/2022	13	0.000%	0.0000
4000467787	104872	169	9/15/2022	9/28/2022	13	0.000%	0.0000
4000467771	107932	5,000	9/15/2022	9/28/2022	13	0.001%	0.0002
4000467864	11536	420	9/16/2022	9/29/2022	13	0.000%	0.0000
4000467866	24259	2,056	9/16/2022	9/29/2022	13	0.001%	0.0001
4000467871	26674	7,560	9/16/2022	9/29/2022	13	0.002%	0.0003
4000467875	30475	63,728	9/16/2022	9/29/2022	13	0.017%	0.0022
4000467876	30475	70,065	9/16/2022	9/29/2022	13	0.018%	0.0024
4000467877	30475	83,757	9/16/2022	9/29/2022	13	0.022%	0.0029
4000467878	30475	60,141	9/16/2022	9/29/2022	13	0.016%	0.0021
4000467879	33956	8,026	9/16/2022	9/29/2022	13	0.002%	0.0003
4000467844	116384	143	9/16/2022	9/29/2022	13	0.000%	0.0000
4000467851	138862	800	9/16/2022	9/29/2022	13	0.000%	0.0000
4000467860	144519	41,400	9/16/2022	9/29/2022	13	0.011%	0.0014
4000467861	144530	5,109	9/16/2022	9/29/2022	13	0.001%	0.0002
4000467935	23681	3,714	9/20/2022	10/3/2022	13	0.001%	0.0001
4000467936	24211	10,252	9/20/2022	10/3/2022	13	0.003%	0.0004
4000467942	26604	1,375	9/20/2022	10/3/2022	13	0.000%	0.0000
4000467945	28619	9,336	9/20/2022	10/3/2022	13	0.002%	0.0003
4000467928	145193	1,330	9/20/2022	10/3/2022	13	0.000%	0.0000
4000468072	11577	4,148	9/23/2022	10/6/2022	13	0.001%	0.0001
4000468076	26016	5,222	9/23/2022	10/6/2022	13	0.001%	0.0002
4000468083	28737	10,050	9/23/2022	10/6/2022	13	0.003%	0.0003
4000468085	30475	73,440	9/23/2022	10/6/2022	13	0.019%	0.0025
4000468086	30475	49,212	9/23/2022	10/6/2022	13	0.013%	0.0017
4000468087	30475	58,073	9/23/2022	10/6/2022	13	0.015%	0.0020
4000468032	26588	1,680	9/23/2022	10/6/2022	13	0.000%	0.0001
4000468036	101853	106,920	9/23/2022	10/6/2022	13	0.028%	0.0037
4000468039	108289	65	9/23/2022	10/6/2022	13	0.000%	0.0000
4000468246	26301	26,964	9/28/2022	10/11/2022	13	0.007%	0.0009
4000468249	26643	1,198	9/28/2022	10/11/2022	13	0.000%	0.0000
4000468261	135537	6,373	9/28/2022	10/11/2022	13	0.002%	0.0002
4000468207	107047	528	9/28/2022	10/11/2022	13	0.000%	0.0000
4000468220	124584	465	9/28/2022	10/11/2022	13	0.000%	0.0000
4000468226	132991	1,000	9/28/2022	10/11/2022	13	0.000%	0.0000
4000468231	143458	14,831	9/28/2022	10/11/2022	13	0.004%	0.0005
4000468235	144794	15,000	9/28/2022	10/11/2022	13	0.004%	0.0005
4000468291	13911	128,170	9/29/2022	10/12/2022	13	0.034%	0.0044
4000468297	25808	3,060	9/29/2022	10/12/2022	13	0.001%	0.0001
4000468309	137825	1,882	9/29/2022	10/12/2022	13	0.000%	0.0001
4000468272	124584	689	9/29/2022	10/12/2022	13	0.000%	0.0000
4000468262	102060	3,000	9/29/2022	10/12/2022	13	0.001%	0.0001
4000468397	11260	13,420	9/30/2022	10/13/2022	13	0.004%	0.0005
4000468398	11426	17,476	9/30/2022	10/13/2022	13	0.005%	0.0006
4000468405	25659	12,153	9/30/2022	10/13/2022	13	0.003%	0.0004
4000468408	26490	3,368	9/30/2022	10/13/2022	13	0.001%	0.0001
4000468414	33203	575	9/30/2022	10/13/2022	13	0.000%	0.0000
4000468417	33975	19,545	9/30/2022	10/13/2022	13	0.005%	0.0007
4000468313	15871	2,286	9/30/2022	10/13/2022	13	0.001%	0.0001
4000468318	26130	162,941	9/30/2022	10/13/2022	13	0.043%	0.0056
4000468331	113967	2,617	9/30/2022	10/13/2022	13	0.001%	0.0001
4000468338	126047	1,143	9/30/2022	10/13/2022	13	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468356	142615	29,568	9/30/2022	10/13/2022	13	0.008%	0.0010
4000468358	142642	2,683	9/30/2022	10/13/2022	13	0.001%	0.0001
4000468365	143270	4,500	9/30/2022	10/13/2022	13	0.001%	0.0002
4000468368	143364	12,300	9/30/2022	10/13/2022	13	0.003%	0.0004
4000468370	143584	35,234	9/30/2022	10/13/2022	13	0.009%	0.0012
4000468388	145034	11,345	9/30/2022	10/13/2022	13	0.003%	0.0004
4000468390	145181	1,350	9/30/2022	10/13/2022	13	0.000%	0.0000
4000468473	132321	104	10/4/2022	10/17/2022	13	0.000%	0.0000
4000468476	142402	400,000	10/4/2022	10/17/2022	13	0.106%	0.0137
4000468486	104951	318	10/5/2022	10/18/2022	13	0.000%	0.0000
4000468517	11304	4,650	10/6/2022	10/19/2022	13	0.001%	0.0002
4000468513	142942	8,562	10/6/2022	10/19/2022	13	0.002%	0.0003
4000468582	11536	840	10/7/2022	10/20/2022	13	0.000%	0.0000
4000468583	17342	1,890	10/7/2022	10/20/2022	13	0.000%	0.0001
4000468584	18267	20,843	10/7/2022	10/20/2022	13	0.005%	0.0007
4000468586	24281	8,287	10/7/2022	10/20/2022	13	0.002%	0.0003
4000468594	28737	1,592	10/7/2022	10/20/2022	13	0.000%	0.0001
4000468597	30475	55,242	10/7/2022	10/20/2022	13	0.015%	0.0019
4000468598	30475	59,116	10/7/2022	10/20/2022	13	0.016%	0.0020
4000468599	30475	70,244	10/7/2022	10/20/2022	13	0.019%	0.0024
4000468600	30475	46,154	10/7/2022	10/20/2022	13	0.012%	0.0016
4000468601	30475	48,249	10/7/2022	10/20/2022	13	0.013%	0.0017
4000468602	30475	50,625	10/7/2022	10/20/2022	13	0.013%	0.0017
4000468603	32808	605	10/7/2022	10/20/2022	13	0.000%	0.0000
4000468604	32853	450	10/7/2022	10/20/2022	13	0.000%	0.0000
4000468545	34943	1,455	10/7/2022	10/20/2022	13	0.000%	0.0000
4000468553	105024	243	10/7/2022	10/20/2022	13	0.000%	0.0000
4000468572	144519	34,611	10/7/2022	10/20/2022	13	0.009%	0.0012
4000468573	144530	46,384	10/7/2022	10/20/2022	13	0.012%	0.0016
4000468646	24211	7,272	10/11/2022	10/24/2022	13	0.002%	0.0002
4000468661	27389	17,595	10/11/2022	10/24/2022	13	0.005%	0.0006
4000468670	124628	9,647	10/11/2022	10/24/2022	13	0.003%	0.0003
4000468681	105195	3,461	10/12/2022	10/25/2022	13	0.001%	0.0001
4000468717	145297	8,427	10/12/2022	10/25/2022	13	0.002%	0.0003
4000468771	24825	6,169	10/13/2022	10/26/2022	13	0.002%	0.0002
4000468772	25908	13,250	10/13/2022	10/26/2022	13	0.003%	0.0005
4000468775	27013	524	10/13/2022	10/26/2022	13	0.000%	0.0000
4000468757	143072	1,601	10/13/2022	10/26/2022	13	0.000%	0.0001
4000468759	143901	310	10/13/2022	10/26/2022	13	0.000%	0.0000
4000468825	26490	1,394	10/14/2022	10/27/2022	13	0.000%	0.0000
4000468829	27704	1,550	10/14/2022	10/27/2022	13	0.000%	0.0001
4000468832	30475	89,264	10/14/2022	10/27/2022	13	0.024%	0.0031
4000468833	30475	97,091	10/14/2022	10/27/2022	13	0.026%	0.0033
4000468834	30475	78,216	10/14/2022	10/27/2022	13	0.021%	0.0027
4000468835	30475	81,540	10/14/2022	10/27/2022	13	0.022%	0.0028
4000468787	15871	6,987	10/14/2022	10/27/2022	13	0.002%	0.0002
4000468788	26130	3,374	10/14/2022	10/27/2022	13	0.001%	0.0001
4000468935	135537	59,088	10/18/2022	10/31/2022	13	0.016%	0.0020
4000468902	103008	1,645	10/18/2022	10/31/2022	13	0.000%	0.0001
4000468911	124628	6,337	10/18/2022	10/31/2022	13	0.002%	0.0002
4000468917	142942	5,591	10/18/2022	10/31/2022	13	0.001%	0.0002
4000468921	145222	966	10/18/2022	10/31/2022	13	0.000%	0.0000
4000468949	145438	2,700	10/19/2022	11/1/2022	13	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468973	32936	49,431	10/19/2022	11/1/2022	13	0.013%	0.0017
4000469026	33133	10,340	10/19/2022	11/1/2022	13	0.003%	0.0004
4000469061	26297	40,585	10/20/2022	11/2/2022	13	0.011%	0.0014
4000469113	25809	2,038	10/21/2022	11/3/2022	13	0.001%	0.0001
4000469114	26604	3,885	10/21/2022	11/3/2022	13	0.001%	0.0001
4000469117	30257	113,187	10/21/2022	11/3/2022	13	0.030%	0.0039
4000469124	34348	4,650	10/21/2022	11/3/2022	13	0.001%	0.0002
4000469079	25147	394,316	10/21/2022	11/3/2022	13	0.104%	0.0135
4000469098	142926	79,690	10/21/2022	11/3/2022	13	0.021%	0.0027
4000469192	13911	1,370	10/25/2022	11/7/2022	13	0.000%	0.0000
4000469176	125742	2,441	10/25/2022	11/7/2022	13	0.001%	0.0001
4000469178	142402	247,867	10/25/2022	11/7/2022	13	0.065%	0.0085
4000469246	28084	1,710	10/26/2022	11/8/2022	13	0.000%	0.0001
4000469250	104725	875	10/26/2022	11/8/2022	13	0.000%	0.0000
4000469210	104872	42	10/26/2022	11/8/2022	13	0.000%	0.0000
4000469313	30475	20,621	10/27/2022	11/9/2022	13	0.005%	0.0007
4000469367	11305	22,078	10/28/2022	11/10/2022	13	0.006%	0.0008
4000469378	26642	4,988	10/28/2022	11/10/2022	13	0.001%	0.0002
4000469382	27962	1,596	10/28/2022	11/10/2022	13	0.000%	0.0001
4000469388	32099	4,725	10/28/2022	11/10/2022	13	0.001%	0.0002
4000469392	34531	25,032	10/28/2022	11/10/2022	13	0.007%	0.0009
4000469337	108289	129	10/28/2022	11/10/2022	13	0.000%	0.0000
4000469339	112103	57,600	10/28/2022	11/10/2022	13	0.015%	0.0020
4000469344	134862	343,836	10/28/2022	11/10/2022	13	0.091%	0.0118
4000469345	135057	10	10/28/2022	11/10/2022	13	0.000%	0.0000
4000469469	11577	4,620	11/1/2022	11/14/2022	13	0.001%	0.0002
4000469473	25808	7,680	11/1/2022	11/14/2022	13	0.002%	0.0003
4000469474	25809	2,433	11/1/2022	11/14/2022	13	0.001%	0.0001
4000469475	26016	1,099	11/1/2022	11/14/2022	13	0.000%	0.0000
4000469462	126928	747	11/1/2022	11/14/2022	13	0.000%	0.0000
4000469536	30475	34,925	11/2/2022	11/15/2022	13	0.009%	0.0012
4000469537	30475	37,875	11/2/2022	11/15/2022	13	0.010%	0.0013
4000469538	30475	23,607	11/2/2022	11/15/2022	13	0.006%	0.0008
4000469539	30475	26,918	11/2/2022	11/15/2022	13	0.007%	0.0009
4000469492	105195	8,951	11/2/2022	11/15/2022	13	0.002%	0.0003
4000469496	126047	1,143	11/2/2022	11/15/2022	13	0.000%	0.0000
4000469503	141025	18,000	11/2/2022	11/15/2022	13	0.005%	0.0006
4000469512	142942	1,734	11/2/2022	11/15/2022	13	0.000%	0.0001
4000469514	143364	12,300	11/2/2022	11/15/2022	13	0.003%	0.0004
4000469486	117159	6,000	11/2/2022	11/15/2022	13	0.002%	0.0002
4000469579	8392	6,429	11/3/2022	11/16/2022	13	0.002%	0.0002
4000469599	134272	15,236	11/3/2022	11/16/2022	13	0.004%	0.0005
4000469567	143400	3,000	11/3/2022	11/16/2022	13	0.001%	0.0001
4000469548	129744	6,450	11/3/2022	11/16/2022	13	0.002%	0.0002
4000469641	25272	5,220	11/4/2022	11/17/2022	13	0.001%	0.0002
4000469661	126165	8,266	11/4/2022	11/17/2022	13	0.002%	0.0003
4000469609	26958	491	11/4/2022	11/17/2022	13	0.000%	0.0000
4000469610	27466	4,056	11/4/2022	11/17/2022	13	0.001%	0.0001
4000469613	104872	1,006	11/4/2022	11/17/2022	13	0.000%	0.0000
4000469630	144816	14,204	11/4/2022	11/17/2022	13	0.004%	0.0005
4000469632	145251	1,630	11/4/2022	11/17/2022	13	0.000%	0.0001
4000469702	8392	15,857	11/8/2022	11/21/2022	13	0.004%	0.0005
4000469704	30475	681	11/8/2022	11/21/2022	13	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469692	141583	330	11/8/2022	11/21/2022	13	0.000%	0.0000
4000469699	145222	2,484	11/8/2022	11/21/2022	13	0.001%	0.0001
4000469744	14463	25,771	11/9/2022	11/22/2022	13	0.007%	0.0009
4000469746	18267	1,920	11/9/2022	11/22/2022	13	0.001%	0.0001
4000469714	105750	1,500	11/9/2022	11/22/2022	13	0.000%	0.0001
4000469736	144519	62,895	11/9/2022	11/22/2022	13	0.017%	0.0022
4000469813	9673	3,700	11/10/2022	11/23/2022	13	0.001%	0.0001
4000469817	24385	1,143	11/10/2022	11/23/2022	13	0.000%	0.0000
4000469823	30475	45,039	11/10/2022	11/23/2022	13	0.012%	0.0015
4000469775	9673	925	11/10/2022	11/23/2022	13	0.000%	0.0000
4000469777	15871	4,373	11/10/2022	11/23/2022	13	0.001%	0.0001
4000469782	103867	7	11/10/2022	11/23/2022	13	0.000%	0.0000
4000469786	116902	84,159	11/10/2022	11/23/2022	13	0.022%	0.0029
4000469803	143573	133,971	11/10/2022	11/23/2022	13	0.035%	0.0046
4000469921	11577	2,625	11/16/2022	11/29/2022	13	0.001%	0.0001
4000469929	26604	47,575	11/16/2022	11/29/2022	13	0.013%	0.0016
4000469935	28737	3,582	11/16/2022	11/29/2022	13	0.001%	0.0001
4000469947	32853	1,440	11/16/2022	11/29/2022	13	0.000%	0.0000
4000469948	32875	600	11/16/2022	11/29/2022	13	0.000%	0.0000
4000469907	105195	14,691	11/16/2022	11/29/2022	13	0.004%	0.0005
4000469914	141826	20,329	11/16/2022	11/29/2022	13	0.005%	0.0007
4000469917	142942	2,421	11/16/2022	11/29/2022	13	0.001%	0.0001
4000469959	15871	5,564	11/17/2022	11/30/2022	13	0.001%	0.0002
4000469961	26130	42,000	11/17/2022	11/30/2022	13	0.011%	0.0014
4000470034	25599	3,711	11/18/2022	12/1/2022	13	0.001%	0.0001
4000470036	26363	829	11/18/2022	12/1/2022	13	0.000%	0.0000
4000470039	26643	913	11/18/2022	12/1/2022	13	0.000%	0.0000
4000470041	27962	456	11/18/2022	12/1/2022	13	0.000%	0.0000
4000470001	103008	1,834	11/18/2022	12/1/2022	13	0.000%	0.0001
4000470004	103676	1,102	11/18/2022	12/1/2022	13	0.000%	0.0000
4000470023	145251	1,726	11/18/2022	12/1/2022	13	0.000%	0.0001
4000470024	145390	3,000	11/18/2022	12/1/2022	13	0.001%	0.0001
4000470132	8392	43,531	11/22/2022	12/5/2022	13	0.011%	0.0015
4000470135	25173	880	11/22/2022	12/5/2022	13	0.000%	0.0000
4000470137	25808	17,220	11/22/2022	12/5/2022	13	0.005%	0.0006
4000470119	142681	81,692	11/22/2022	12/5/2022	13	0.022%	0.0028
4000470121	143072	24,636	11/22/2022	12/5/2022	13	0.006%	0.0008
4000470124	145222	8,418	11/22/2022	12/5/2022	13	0.002%	0.0003
4000470198	18267	6,316	11/23/2022	12/6/2022	13	0.002%	0.0002
4000470199	24385	650	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470204	27305	3,000	11/23/2022	12/6/2022	13	0.001%	0.0001
4000470208	30257	27,865	11/23/2022	12/6/2022	13	0.007%	0.0010
4000470221	34341	7,000	11/23/2022	12/6/2022	13	0.002%	0.0002
4000470224	105195	518	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470225	117331	3,250	11/23/2022	12/6/2022	13	0.001%	0.0001
4000470146	4502	6,666	11/23/2022	12/6/2022	13	0.002%	0.0002
4000470149	7214	698,562	11/23/2022	12/6/2022	13	0.184%	0.0240
4000470153	26130	30,488	11/23/2022	12/6/2022	13	0.008%	0.0010
4000470155	105195	16,139	11/23/2022	12/6/2022	13	0.004%	0.0006
4000470161	118807	636	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470168	141256	36	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470174	143111	6,200	11/23/2022	12/6/2022	13	0.002%	0.0002
4000470175	143340	343,358	11/23/2022	12/6/2022	13	0.091%	0.0118

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470185	144567	1,450	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470188	145093	723	11/23/2022	12/6/2022	13	0.000%	0.0000
4000470353	25029	7,280	11/30/2022	12/13/2022	13	0.002%	0.0002
4000470323	119251	75,486	11/30/2022	12/13/2022	13	0.020%	0.0026
4000470325	123377	25,245	11/30/2022	12/13/2022	13	0.007%	0.0009
4000470326	124628	36,910	11/30/2022	12/13/2022	13	0.010%	0.0013
4000470331	142942	3,460	11/30/2022	12/13/2022	13	0.001%	0.0001
4000470342	145222	736	11/30/2022	12/13/2022	13	0.000%	0.0000
4000470440	27994	38,720	12/1/2022	12/14/2022	13	0.010%	0.0013
4000470524	24259	64	12/2/2022	12/15/2022	13	0.000%	0.0000
4000470525	25644	5,125	12/2/2022	12/15/2022	13	0.001%	0.0002
4000470526	25905	1,300	12/2/2022	12/15/2022	13	0.000%	0.0000
4000470528	26674	2,100	12/2/2022	12/15/2022	13	0.001%	0.0001
4000470459	104872	2,256	12/2/2022	12/15/2022	13	0.001%	0.0001
4000470462	126047	1,400	12/2/2022	12/15/2022	13	0.000%	0.0000
4000470465	131647	2,525	12/2/2022	12/15/2022	13	0.001%	0.0001
4000470476	142002	7,696	12/2/2022	12/15/2022	13	0.002%	0.0003
4000470477	142162	11,000	12/2/2022	12/15/2022	13	0.003%	0.0004
4000470484	142885	16,730	12/2/2022	12/15/2022	13	0.004%	0.0006
4000470501	144422	103,788	12/2/2022	12/15/2022	13	0.027%	0.0036
4000470451	123042	2,871	12/2/2022	12/15/2022	13	0.001%	0.0001
4000470593	28737	2,200	12/6/2022	12/19/2022	13	0.001%	0.0001
4000470637	26493	2,352	12/7/2022	12/20/2022	13	0.001%	0.0001
4000470602	15871	1,058	12/7/2022	12/20/2022	13	0.000%	0.0000
4000470607	105195	1,860	12/7/2022	12/20/2022	13	0.000%	0.0001
4000470681	27068	2,280	12/8/2022	12/21/2022	13	0.001%	0.0001
4000470730	26604	39,755	12/9/2022	12/22/2022	13	0.010%	0.0014
4000470731	26643	916	12/9/2022	12/22/2022	13	0.000%	0.0000
4000470702	132507	8,215	12/9/2022	12/22/2022	13	0.002%	0.0003
4000470713	143929	90,664	12/9/2022	12/22/2022	13	0.024%	0.0031
4000470715	144561	5,000	12/9/2022	12/22/2022	13	0.001%	0.0002
4000470813	33624	179,847	12/14/2022	12/27/2022	13	0.047%	0.0062
4000470904	11305	1,601	12/15/2022	12/28/2022	13	0.000%	0.0001
4000470907	25938	14,800	12/15/2022	12/28/2022	13	0.004%	0.0005
4000470908	26381	1,280	12/15/2022	12/28/2022	13	0.000%	0.0000
4000470877	35151	1,980	12/15/2022	12/28/2022	13	0.001%	0.0001
4000470884	116384	54	12/15/2022	12/28/2022	13	0.000%	0.0000
4000471000	11054	339	12/16/2022	12/29/2022	13	0.000%	0.0000
4000471003	24825	7,600	12/16/2022	12/29/2022	13	0.002%	0.0003
4000471006	25599	2,231	12/16/2022	12/29/2022	13	0.001%	0.0001
4000471008	27704	2,500	12/16/2022	12/29/2022	13	0.001%	0.0001
4000471023	117331	3,000	12/16/2022	12/29/2022	13	0.001%	0.0001
4000470921	15871	1,135	12/16/2022	12/29/2022	13	0.000%	0.0000
4000470924	32869	3,222	12/16/2022	12/29/2022	13	0.001%	0.0001
4000470937	123915	3,610	12/16/2022	12/29/2022	13	0.001%	0.0001
4000470950	141021	8,100	12/16/2022	12/29/2022	13	0.002%	0.0003
4000470951	141025	18,000	12/16/2022	12/29/2022	13	0.005%	0.0006
4000470953	141370	13,250	12/16/2022	12/29/2022	13	0.003%	0.0005
4000470959	142162	11,000	12/16/2022	12/29/2022	13	0.003%	0.0004
4000470965	142942	29,043	12/16/2022	12/29/2022	13	0.008%	0.0010
4000470972	143929	22,666	12/16/2022	12/29/2022	13	0.006%	0.0008
4000470986	144927	6,000	12/16/2022	12/29/2022	13	0.002%	0.0002
4000470989	145034	11,345	12/16/2022	12/29/2022	13	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470991	145067	2,200	12/16/2022	12/29/2022	13	0.001%	0.0001
4000470994	145258	7,785	12/16/2022	12/29/2022	13	0.002%	0.0003
4000470995	145293	22,037	12/16/2022	12/29/2022	13	0.006%	0.0008
4000470996	145500	21,684	12/16/2022	12/29/2022	13	0.006%	0.0007
4000471140	11474	1,750	12/21/2022	1/3/2023	13	0.000%	0.0001
4000471147	24259	1,028	12/21/2022	1/3/2023	13	0.000%	0.0000
4000471148	24383	680	12/21/2022	1/3/2023	13	0.000%	0.0000
4000471150	25708	2,466	12/21/2022	1/3/2023	13	0.001%	0.0001
4000471151	26297	8,841	12/21/2022	1/3/2023	13	0.002%	0.0003
4000471152	26301	4,494	12/21/2022	1/3/2023	13	0.001%	0.0002
4000471157	26604	3,340	12/21/2022	1/3/2023	13	0.001%	0.0001
4000471170	34972	99,650	12/21/2022	1/3/2023	13	0.026%	0.0034
4000471171	117331	9,900	12/21/2022	1/3/2023	13	0.003%	0.0003
4000471172	124943	998	12/21/2022	1/3/2023	13	0.000%	0.0000
4000471173	125360	4,835	12/21/2022	1/3/2023	13	0.001%	0.0002
4000471174	126165	10,333	12/21/2022	1/3/2023	13	0.003%	0.0004
4000471110	26256	5,625	12/21/2022	1/3/2023	13	0.001%	0.0002
4000471116	102391	795,233	12/21/2022	1/3/2023	13	0.210%	0.0273
4000471118	109995	198,443	12/21/2022	1/3/2023	13	0.052%	0.0068
4000471123	132507	550	12/21/2022	1/3/2023	13	0.000%	0.0000
4000471209	30257	122,318	12/22/2022	1/4/2023	13	0.032%	0.0042
4000471210	33354	16,613	12/22/2022	1/4/2023	13	0.004%	0.0006
4000471211	33956	2,392	12/22/2022	1/4/2023	13	0.001%	0.0001
4000471212	34064	366	12/22/2022	1/4/2023	13	0.000%	0.0000
4000471177	27094	1,766	12/22/2022	1/4/2023	13	0.000%	0.0001
4000471180	105195	9,931	12/22/2022	1/4/2023	13	0.003%	0.0003
4000471182	116384	156	12/22/2022	1/4/2023	13	0.000%	0.0000
4000471187	125742	6,648	12/22/2022	1/4/2023	13	0.002%	0.0002
4000471188	126371	200,000	12/22/2022	1/4/2023	13	0.053%	0.0069
4000471191	141101	36,143	12/22/2022	1/4/2023	13	0.010%	0.0012
4000471196	144084	5,360	12/22/2022	1/4/2023	13	0.001%	0.0002
4000471198	144567	10,894	12/22/2022	1/4/2023	13	0.003%	0.0004
4000471244	11426	10,091	12/23/2022	1/5/2023	13	0.003%	0.0003
4000471248	24259	6,231	12/23/2022	1/5/2023	13	0.002%	0.0002
4000471249	25908	11,938	12/23/2022	1/5/2023	13	0.003%	0.0004
4000471254	26659	15,521	12/23/2022	1/5/2023	13	0.004%	0.0005
4000471260	33203	5,405	12/23/2022	1/5/2023	13	0.001%	0.0002
4000471266	117331	3,000	12/23/2022	1/5/2023	13	0.001%	0.0001
4000471222	22902	5,697	12/23/2022	1/5/2023	13	0.002%	0.0002
4000471224	25147	1,078,291	12/23/2022	1/5/2023	13	0.284%	0.0370
4000471231	125742	11,460	12/23/2022	1/5/2023	13	0.003%	0.0004
4000471233	139982	9,445	12/23/2022	1/5/2023	13	0.002%	0.0003
4000471236	143072	93,811	12/23/2022	1/5/2023	13	0.025%	0.0032
4000471284	24113	31,281	12/27/2022	1/9/2023	13	0.008%	0.0011
4000471279	208279	122	12/27/2022	1/9/2023	13	0.000%	0.0000
4000471312	142942	2,093	12/28/2022	1/10/2023	13	0.001%	0.0001
4000471366	5673	6,800	12/29/2022	1/11/2023	13	0.002%	0.0002
4000471367	8392	5,143	12/29/2022	1/11/2023	13	0.001%	0.0002
4000471377	18275	4,128	12/29/2022	1/11/2023	13	0.001%	0.0001
4000471349	107047	1,848	12/29/2022	1/11/2023	13	0.000%	0.0001
4000471356	134862	8,207	12/29/2022	1/11/2023	13	0.002%	0.0003
4000471488	25599	7,107	12/30/2022	1/12/2023	13	0.002%	0.0002
4000471489	25659	12,015	12/30/2022	1/12/2023	13	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471496	27552	74,638	12/30/2022	1/12/2023	13	0.020%	0.0026
4000471498	28084	1,995	12/30/2022	1/12/2023	13	0.001%	0.0001
4000471511	33203	920	12/30/2022	1/12/2023	13	0.000%	0.0000
4000471522	124943	760	12/30/2022	1/12/2023	13	0.000%	0.0000
4000471416	4208	171,136	12/30/2022	1/12/2023	13	0.045%	0.0059
4000471418	4765	65,423	12/30/2022	1/12/2023	13	0.017%	0.0022
4000471420	6396	251,772	12/30/2022	1/12/2023	13	0.066%	0.0086
4000471422	18785	19,050	12/30/2022	1/12/2023	13	0.005%	0.0007
4000471429	106674	76	12/30/2022	1/12/2023	13	0.000%	0.0000
4000471430	110291	11,210	12/30/2022	1/12/2023	13	0.003%	0.0004
4000471433	113448	12,626	12/30/2022	1/12/2023	13	0.003%	0.0004
4000471435	116384	15	12/30/2022	1/12/2023	13	0.000%	0.0000
4000471437	125742	21,080	12/30/2022	1/12/2023	13	0.006%	0.0007
4000471438	125814	31	12/30/2022	1/12/2023	13	0.000%	0.0000
4000471444	141610	474,490	12/30/2022	1/12/2023	13	0.125%	0.0163
4000471446	142615	2,184	12/30/2022	1/12/2023	13	0.001%	0.0001
4000471448	143072	19,035	12/30/2022	1/12/2023	13	0.005%	0.0007
4000471449	143243	35,904	12/30/2022	1/12/2023	13	0.009%	0.0012
4000471456	143577	1,830	12/30/2022	1/12/2023	13	0.000%	0.0001
4000471462	143892	3,465	12/30/2022	1/12/2023	13	0.001%	0.0001
4000471468	144986	4,000	12/30/2022	1/12/2023	13	0.001%	0.0001
4000459575	34888	1,440	1/4/2022	1/18/2022	14	0.000%	0.0001
4000459611	15871	2,697	1/6/2022	1/20/2022	14	0.001%	0.0001
4000459626	137757	17,460	1/6/2022	1/20/2022	14	0.005%	0.0006
4000459630	142926	26,700	1/6/2022	1/20/2022	14	0.007%	0.0010
4000459675	11536	5,355	1/7/2022	1/21/2022	14	0.001%	0.0002
4000459687	26643	3,113	1/7/2022	1/21/2022	14	0.001%	0.0001
4000459693	33770	215,408	1/7/2022	1/21/2022	14	0.057%	0.0080
4000459711	8998	34,628	1/10/2022	1/24/2022	14	0.009%	0.0013
4000459715	11372	2,890	1/10/2022	1/24/2022	14	0.001%	0.0001
4000459723	25437	750	1/10/2022	1/24/2022	14	0.000%	0.0000
4000459725	26207	32,600	1/10/2022	1/24/2022	14	0.009%	0.0012
4000459727	26338	2,832	1/10/2022	1/24/2022	14	0.001%	0.0001
4000459732	26642	23,655	1/10/2022	1/24/2022	14	0.006%	0.0009
4000459710	144862	13	1/10/2022	1/24/2022	14	0.000%	0.0000
4000459698	129753	250	1/10/2022	1/24/2022	14	0.000%	0.0000
4000459699	129753	250	1/10/2022	1/24/2022	14	0.000%	0.0000
4000459700	129753	250	1/10/2022	1/24/2022	14	0.000%	0.0000
4000459744	103471	1,220	1/11/2022	1/25/2022	14	0.000%	0.0000
4000459796	26639	2,700	1/12/2022	1/26/2022	14	0.001%	0.0001
4000459805	124628	15,138	1/12/2022	1/26/2022	14	0.004%	0.0006
4000459874	34341	12,600	1/13/2022	1/27/2022	14	0.003%	0.0005
4000459878	126165	2,767	1/13/2022	1/27/2022	14	0.001%	0.0001
4000459857	144863	1,000	1/13/2022	1/27/2022	14	0.000%	0.0000
4000459808	114121	4,025	1/13/2022	1/27/2022	14	0.001%	0.0001
4000459902	10630	7,920	1/14/2022	1/28/2022	14	0.002%	0.0003
4000459903	24251	7,260	1/14/2022	1/28/2022	14	0.002%	0.0003
4000459917	32939	77,608	1/14/2022	1/28/2022	14	0.020%	0.0029
4000459935	32969	132,361	1/14/2022	1/28/2022	14	0.035%	0.0049
4000459960	26312	23,456	1/18/2022	2/1/2022	14	0.006%	0.0009
4000460016	22798	68,363	1/19/2022	2/2/2022	14	0.018%	0.0025
4000460109	104872	166	1/21/2022	2/4/2022	14	0.000%	0.0000
4000460112	118807	40	1/21/2022	2/4/2022	14	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460154	25659	2,285	1/24/2022	2/7/2022	14	0.001%	0.0001
4000460168	126165	1,550	1/24/2022	2/7/2022	14	0.000%	0.0001
4000460138	126928	27	1/24/2022	2/7/2022	14	0.000%	0.0000
4000460229	30580	3,105	1/25/2022	2/8/2022	14	0.001%	0.0001
4000460232	104872	1,027	1/25/2022	2/8/2022	14	0.000%	0.0000
4000460300	27962	3,225	1/26/2022	2/9/2022	14	0.001%	0.0001
4000460288	144644	70	1/26/2022	2/9/2022	14	0.000%	0.0000
4000460275	119459	4,723	1/26/2022	2/9/2022	14	0.001%	0.0002
4000460430	25029	2,392	1/27/2022	2/10/2022	14	0.001%	0.0001
4000460440	34173	13,766	1/27/2022	2/10/2022	14	0.004%	0.0005
4000460449	33078	4,356	1/27/2022	2/10/2022	14	0.001%	0.0002
4000460317	101853	55,780	1/27/2022	2/10/2022	14	0.015%	0.0021
4000460340	32953	41,281	1/27/2022	2/10/2022	14	0.011%	0.0015
4000460342	32957	3,272	1/27/2022	2/10/2022	14	0.001%	0.0001
4000460350	33024	584,514	1/27/2022	2/10/2022	14	0.154%	0.0216
4000460374	33095	727	1/27/2022	2/10/2022	14	0.000%	0.0000
4000460381	33103	5,909	1/27/2022	2/10/2022	14	0.002%	0.0002
4000460383	33106	2,825	1/27/2022	2/10/2022	14	0.001%	0.0001
4000460385	33110	36,922	1/27/2022	2/10/2022	14	0.010%	0.0014
4000460388	33114	124,661	1/27/2022	2/10/2022	14	0.033%	0.0046
4000460400	33128	41,492	1/27/2022	2/10/2022	14	0.011%	0.0015
4000460406	33134	3,621	1/27/2022	2/10/2022	14	0.001%	0.0001
4000460413	33141	8,031	1/27/2022	2/10/2022	14	0.002%	0.0003
4000460488	130375	5,091	1/28/2022	2/11/2022	14	0.001%	0.0002
4000460461	139089	297	1/28/2022	2/11/2022	14	0.000%	0.0000
4000460495	33069	80,971	1/28/2022	2/11/2022	14	0.021%	0.0030
4000460526	33113	14,355	1/28/2022	2/11/2022	14	0.004%	0.0005
4000460544	33133	9,670	1/28/2022	2/11/2022	14	0.003%	0.0004
4000460585	11304	9,825	1/31/2022	2/14/2022	14	0.003%	0.0004
4000460563	4502	3,808	1/31/2022	2/14/2022	14	0.001%	0.0001
4000460628	131647	2,338	2/1/2022	2/15/2022	14	0.001%	0.0001
4000460656	143807	1,058	2/1/2022	2/15/2022	14	0.000%	0.0000
4000460658	143929	22,666	2/1/2022	2/15/2022	14	0.006%	0.0008
4000460681	111559	3,518	2/2/2022	2/16/2022	14	0.001%	0.0001
4000460693	139089	32	2/2/2022	2/16/2022	14	0.000%	0.0000
4000460788	9891	13,740	2/4/2022	2/18/2022	14	0.004%	0.0005
4000460789	11054	1,284	2/4/2022	2/18/2022	14	0.000%	0.0000
4000460797	27994	5,115	2/4/2022	2/18/2022	14	0.001%	0.0002
4000460767	102473	4,200	2/4/2022	2/18/2022	14	0.001%	0.0002
4000460879	25173	2,640	2/8/2022	2/22/2022	14	0.001%	0.0001
4000460903	14463	7,218	2/9/2022	2/23/2022	14	0.002%	0.0003
4000460910	27512	961	2/9/2022	2/23/2022	14	0.000%	0.0000
4000460924	134272	235,677	2/9/2022	2/23/2022	14	0.062%	0.0087
4000460925	33089	32,441	2/9/2022	2/23/2022	14	0.009%	0.0012
4000460960	25809	2,118	2/10/2022	2/24/2022	14	0.001%	0.0001
4000461032	13534	78,654	2/11/2022	2/25/2022	14	0.021%	0.0029
4000461034	25173	880	2/11/2022	2/25/2022	14	0.000%	0.0000
4000461036	27677	176,000	2/11/2022	2/25/2022	14	0.046%	0.0065
4000461040	32138	14,078	2/11/2022	2/25/2022	14	0.004%	0.0005
4000461043	117331	40,800	2/11/2022	2/25/2022	14	0.011%	0.0015
4000460992	100103	197	2/11/2022	2/25/2022	14	0.000%	0.0000
4000460994	102637	173	2/11/2022	2/25/2022	14	0.000%	0.0000
4000461025	143270	1,617	2/11/2022	2/25/2022	14	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461072	27389	575	2/14/2022	2/28/2022	14	0.000%	0.0000
4000461075	126165	5,281	2/14/2022	2/28/2022	14	0.001%	0.0002
4000461053	139128	709	2/14/2022	2/28/2022	14	0.000%	0.0000
4000461146	24251	11,730	2/16/2022	3/2/2022	14	0.003%	0.0004
4000461189	24191	5,693	2/17/2022	3/3/2022	14	0.002%	0.0002
4000461163	24191	1,481	2/17/2022	3/3/2022	14	0.000%	0.0001
4000461252	28737	2,700	2/18/2022	3/4/2022	14	0.001%	0.0001
4000461213	101853	8,466	2/18/2022	3/4/2022	14	0.002%	0.0003
4000461224	124752	988	2/18/2022	3/4/2022	14	0.000%	0.0000
4000461236	142926	16,114	2/18/2022	3/4/2022	14	0.004%	0.0006
4000461274	119251	6,470	2/22/2022	3/8/2022	14	0.002%	0.0002
4000461291	143477	2,908	2/22/2022	3/8/2022	14	0.001%	0.0001
4000461350	26297	607	2/23/2022	3/9/2022	14	0.000%	0.0000
4000461356	26643	49,194	2/23/2022	3/9/2022	14	0.013%	0.0018
4000461361	27068	3,306	2/23/2022	3/9/2022	14	0.001%	0.0001
4000461364	106699	2,025	2/23/2022	3/9/2022	14	0.001%	0.0001
4000461326	124628	32,751	2/23/2022	3/9/2022	14	0.009%	0.0012
4000461394	25029	3,900	2/24/2022	3/10/2022	14	0.001%	0.0001
4000461389	144581	725	2/24/2022	3/10/2022	14	0.000%	0.0000
4000461440	8998	23,841	2/25/2022	3/11/2022	14	0.006%	0.0009
4000461455	28084	15,010	2/25/2022	3/11/2022	14	0.004%	0.0006
4000461460	32537	770	2/25/2022	3/11/2022	14	0.000%	0.0000
4000461431	142942	35,732	2/25/2022	3/11/2022	14	0.009%	0.0013
4000461472	100111	500	2/28/2022	3/14/2022	14	0.000%	0.0000
4000461544	22798	66,989	3/2/2022	3/16/2022	14	0.018%	0.0025
4000461609	108289	400	3/3/2022	3/17/2022	14	0.000%	0.0000
4000461614	142926	231,350	3/3/2022	3/17/2022	14	0.061%	0.0085
4000461658	24251	600	3/4/2022	3/18/2022	14	0.000%	0.0000
4000461671	34348	3,090	3/4/2022	3/18/2022	14	0.001%	0.0001
4000461646	142942	15,982	3/4/2022	3/18/2022	14	0.004%	0.0006
4000461651	144344	5,000	3/4/2022	3/18/2022	14	0.001%	0.0002
4000461653	144666	8,722	3/4/2022	3/18/2022	14	0.002%	0.0003
4000461686	113731	2,500	3/7/2022	3/21/2022	14	0.001%	0.0001
4000461746	139089	38	3/9/2022	3/23/2022	14	0.000%	0.0000
4000461747	139089	1,344	3/9/2022	3/23/2022	14	0.000%	0.0000
4000461748	141346	134,310	3/9/2022	3/23/2022	14	0.035%	0.0050
4000461789	24191	332	3/10/2022	3/24/2022	14	0.000%	0.0000
4000461807	125016	1,434	3/10/2022	3/24/2022	14	0.000%	0.0001
4000461831	142942	18,809	3/11/2022	3/25/2022	14	0.005%	0.0007
4000461833	143741	950	3/11/2022	3/25/2022	14	0.000%	0.0000
4000461872	33030	107,452	3/14/2022	3/28/2022	14	0.028%	0.0040
4000461873	33089	32,508	3/14/2022	3/28/2022	14	0.009%	0.0012
4000461891	130375	3,000	3/15/2022	3/29/2022	14	0.001%	0.0001
4000461956	33946	68,973	3/16/2022	3/30/2022	14	0.018%	0.0025
4000461928	26312	21,938	3/16/2022	3/30/2022	14	0.006%	0.0008
4000462044	26643	8,958	3/18/2022	4/1/2022	14	0.002%	0.0003
4000462068	124628	28,136	3/21/2022	4/4/2022	14	0.007%	0.0010
4000462077	139275	195	3/21/2022	4/4/2022	14	0.000%	0.0000
4000462227	13911	460	3/25/2022	4/8/2022	14	0.000%	0.0000
4000462204	29254	6,456	3/25/2022	4/8/2022	14	0.002%	0.0002
4000462275	32853	8,100	3/28/2022	4/11/2022	14	0.002%	0.0003
4000462326	101218	16,000	3/30/2022	4/13/2022	14	0.004%	0.0006
4000462375	144999	250	3/30/2022	4/13/2022	14	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462319	117781	250	3/30/2022	4/13/2022	14	0.000%	0.0000
4000462433	9673	925	3/31/2022	4/14/2022	14	0.000%	0.0000
4000462455	28737	12,050	3/31/2022	4/14/2022	14	0.003%	0.0004
4000462407	14875	1,548	3/31/2022	4/14/2022	14	0.000%	0.0001
4000462412	102473	48,761	3/31/2022	4/14/2022	14	0.013%	0.0018
4000462475	9891	2,256	4/1/2022	4/15/2022	14	0.001%	0.0001
4000462479	103047	135	4/1/2022	4/15/2022	14	0.000%	0.0000
4000462487	114121	15,229	4/1/2022	4/15/2022	14	0.004%	0.0006
4000462496	137512	50,000	4/1/2022	4/15/2022	14	0.013%	0.0018
4000462502	142870	19,982	4/1/2022	4/15/2022	14	0.005%	0.0007
4000462515	145030	1,000	4/1/2022	4/15/2022	14	0.000%	0.0000
4000462471	116902	7,480	4/1/2022	4/15/2022	14	0.002%	0.0003
4000462579	144213	13,000	4/4/2022	4/18/2022	14	0.003%	0.0005
4000462604	139089	37	4/5/2022	4/19/2022	14	0.000%	0.0000
4000462682	32896	1,163	4/7/2022	4/21/2022	14	0.000%	0.0000
4000462683	33924	214	4/7/2022	4/21/2022	14	0.000%	0.0000
4000462713	143790	35,000	4/8/2022	4/22/2022	14	0.009%	0.0013
4000462715	144270	129,459	4/8/2022	4/22/2022	14	0.034%	0.0048
4000462762	11054	1,329	4/11/2022	4/25/2022	14	0.000%	0.0000
4000462771	26643	4,475	4/11/2022	4/25/2022	14	0.001%	0.0002
4000462755	142942	6,926	4/11/2022	4/25/2022	14	0.002%	0.0003
4000462785	132113	150	4/12/2022	4/26/2022	14	0.000%	0.0000
4000462807	107313	2,000	4/13/2022	4/27/2022	14	0.001%	0.0001
4000462897	11372	1,175	4/14/2022	4/28/2022	14	0.000%	0.0000
4000462907	25987	800	4/14/2022	4/28/2022	14	0.000%	0.0000
4000462912	29334	338	4/14/2022	4/28/2022	14	0.000%	0.0000
4000462921	32897	400	4/14/2022	4/28/2022	14	0.000%	0.0000
4000462991	135537	27,201	4/19/2022	5/3/2022	14	0.007%	0.0010
4000463025	34173	1,139	4/20/2022	5/4/2022	14	0.000%	0.0000
4000463060	26382	819	4/21/2022	5/5/2022	14	0.000%	0.0000
4000463115	13911	52,380	4/22/2022	5/6/2022	14	0.014%	0.0019
4000463119	26016	1,910	4/22/2022	5/6/2022	14	0.001%	0.0001
4000463083	36297	10,297	4/22/2022	5/6/2022	14	0.003%	0.0004
4000463103	143477	3,100	4/22/2022	5/6/2022	14	0.001%	0.0001
4000463172	23681	4,563	4/25/2022	5/9/2022	14	0.001%	0.0002
4000463158	140286	50,000	4/25/2022	5/9/2022	14	0.013%	0.0018
4000463204	120033	3,069	4/26/2022	5/10/2022	14	0.001%	0.0001
4000463230	11304	3,300	4/27/2022	5/11/2022	14	0.001%	0.0001
4000463293	13911	43,613	4/28/2022	5/12/2022	14	0.012%	0.0016
4000463302	25708	1,717	4/28/2022	5/12/2022	14	0.000%	0.0001
4000463366	9673	20,225	4/29/2022	5/13/2022	14	0.005%	0.0007
4000463367	9891	8,535	4/29/2022	5/13/2022	14	0.002%	0.0003
4000463402	130375	44,372	4/29/2022	5/13/2022	14	0.012%	0.0016
4000463356	143694	3,698	4/29/2022	5/13/2022	14	0.001%	0.0001
4000463429	25808	960	5/2/2022	5/16/2022	14	0.000%	0.0000
4000463433	26604	4,605	5/2/2022	5/16/2022	14	0.001%	0.0002
4000463435	26679	11,750	5/2/2022	5/16/2022	14	0.003%	0.0004
4000463505	11304	6,225	5/3/2022	5/17/2022	14	0.002%	0.0002
4000463452	114121	4,025	5/3/2022	5/17/2022	14	0.001%	0.0001
4000463535	23681	4,245	5/4/2022	5/18/2022	14	0.001%	0.0002
4000463523	139089	37	5/4/2022	5/18/2022	14	0.000%	0.0000
4000463657	134480	272	5/10/2022	5/24/2022	14	0.000%	0.0000
4000463658	139275	266	5/10/2022	5/24/2022	14	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463660	142942	3,269	5/10/2022	5/24/2022	14	0.001%	0.0001
4000463733	125009	25,151	5/12/2022	5/26/2022	14	0.007%	0.0009
4000463734	125009	14,242	5/12/2022	5/26/2022	14	0.004%	0.0005
4000463814	32356	916	5/13/2022	5/27/2022	14	0.000%	0.0000
4000463820	34348	1,500	5/13/2022	5/27/2022	14	0.000%	0.0001
4000463921	27389	36,685	5/17/2022	5/31/2022	14	0.010%	0.0014
4000463909	107537	1,022	5/17/2022	5/31/2022	14	0.000%	0.0000
4000463910	108227	1,397	5/17/2022	5/31/2022	14	0.000%	0.0001
4000463912	126928	1,913	5/17/2022	5/31/2022	14	0.001%	0.0001
4000463947	8392	106,270	5/18/2022	6/1/2022	14	0.028%	0.0039
4000463958	26674	1,820	5/18/2022	6/1/2022	14	0.000%	0.0001
4000463970	34531	26,537	5/18/2022	6/1/2022	14	0.007%	0.0010
4000463944	143577	10,644	5/18/2022	6/1/2022	14	0.003%	0.0004
4000464012	130375	371	5/19/2022	6/2/2022	14	0.000%	0.0000
4000464070	107855	2,500	5/23/2022	6/6/2022	14	0.001%	0.0001
4000464074	116902	550	5/23/2022	6/6/2022	14	0.000%	0.0000
4000464080	132321	106	5/23/2022	6/6/2022	14	0.000%	0.0000
4000464081	138473	2,500	5/23/2022	6/6/2022	14	0.001%	0.0001
4000464087	145157	3,660	5/23/2022	6/6/2022	14	0.001%	0.0001
4000464110	145142	1,932	5/24/2022	6/7/2022	14	0.001%	0.0001
4000464161	11304	3,600	5/25/2022	6/8/2022	14	0.001%	0.0001
4000464168	25987	500	5/25/2022	6/8/2022	14	0.000%	0.0000
4000464174	28619	10,241	5/25/2022	6/8/2022	14	0.003%	0.0004
4000464209	8998	840	5/26/2022	6/9/2022	14	0.000%	0.0000
4000464291	9891	2,522	5/27/2022	6/10/2022	14	0.001%	0.0001
4000464251	35151	2,250	5/27/2022	6/10/2022	14	0.001%	0.0001
4000464267	129383	1,000	5/27/2022	6/10/2022	14	0.000%	0.0000
4000464361	26644	20,183	5/31/2022	6/14/2022	14	0.005%	0.0007
4000464435	139089	347	6/2/2022	6/16/2022	14	0.000%	0.0000
4000464517	144344	4,000	6/3/2022	6/17/2022	14	0.001%	0.0001
4000464544	33101	10,827	6/3/2022	6/17/2022	14	0.003%	0.0004
4000464602	28619	4,132	6/7/2022	6/21/2022	14	0.001%	0.0002
4000464608	32897	2,000	6/7/2022	6/21/2022	14	0.001%	0.0001
4000464583	143436	836	6/7/2022	6/21/2022	14	0.000%	0.0000
4000464577	110195	3,000	6/7/2022	6/21/2022	14	0.001%	0.0001
4000464635	8392	32,115	6/8/2022	6/22/2022	14	0.008%	0.0012
4000464620	125302	2,500	6/8/2022	6/22/2022	14	0.001%	0.0001
4000464623	128888	25,025	6/8/2022	6/22/2022	14	0.007%	0.0009
4000464660	144583	4,500	6/9/2022	6/23/2022	14	0.001%	0.0002
4000464719	18267	2,392	6/10/2022	6/24/2022	14	0.001%	0.0001
4000464686	25147	17,147	6/10/2022	6/24/2022	14	0.005%	0.0006
4000464693	105195	1,661	6/10/2022	6/24/2022	14	0.000%	0.0001
4000464701	129891	31,050	6/10/2022	6/24/2022	14	0.008%	0.0011
4000464779	27962	4,787	6/13/2022	6/27/2022	14	0.001%	0.0002
4000464785	126165	689	6/13/2022	6/27/2022	14	0.000%	0.0000
4000464747	142942	5,644	6/13/2022	6/27/2022	14	0.001%	0.0002
4000464751	144955	396	6/13/2022	6/27/2022	14	0.000%	0.0000
4000464753	207824	37,500	6/13/2022	6/27/2022	14	0.010%	0.0014
4000464855	28619	19,441	6/15/2022	6/29/2022	14	0.005%	0.0007
4000464937	9891	6,312	6/17/2022	7/1/2022	14	0.002%	0.0002
4000464946	26301	2,397	6/17/2022	7/1/2022	14	0.001%	0.0001
4000464948	26363	4,032	6/17/2022	7/1/2022	14	0.001%	0.0001
4000464949	26588	15,910	6/17/2022	7/1/2022	14	0.004%	0.0006

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464950	26604	12,380	6/17/2022	7/1/2022	14	0.003%	0.0005
4000464951	26674	1,120	6/17/2022	7/1/2022	14	0.000%	0.0000
4000464969	34972	77,250	6/17/2022	7/1/2022	14	0.020%	0.0029
4000464978	137825	36	6/17/2022	7/1/2022	14	0.000%	0.0000
4000464899	10439	550	6/17/2022	7/1/2022	14	0.000%	0.0000
4000464902	30580	8,285	6/17/2022	7/1/2022	14	0.002%	0.0003
4000464905	103471	5,756	6/17/2022	7/1/2022	14	0.002%	0.0002
4000464922	142926	94,016	6/17/2022	7/1/2022	14	0.025%	0.0035
4000465004	103763	4,000	6/21/2022	7/5/2022	14	0.001%	0.0001
4000465021	26297	450	6/22/2022	7/6/2022	14	0.000%	0.0000
4000465081	143994	5,282	6/23/2022	7/7/2022	14	0.001%	0.0002
4000465154	25131	380	6/24/2022	7/8/2022	14	0.000%	0.0000
4000465161	27962	570	6/24/2022	7/8/2022	14	0.000%	0.0000
4000465139	144791	800	6/24/2022	7/8/2022	14	0.000%	0.0000
4000465201	9121	1,300	6/27/2022	7/11/2022	14	0.000%	0.0000
4000465204	13911	48,165	6/27/2022	7/11/2022	14	0.013%	0.0018
4000465206	14463	28,744	6/27/2022	7/11/2022	14	0.008%	0.0011
4000465210	24211	3,333	6/27/2022	7/11/2022	14	0.001%	0.0001
4000465217	25809	673	6/27/2022	7/11/2022	14	0.000%	0.0000
4000465221	26639	2,835	6/27/2022	7/11/2022	14	0.001%	0.0001
4000465176	12331	25,000	6/27/2022	7/11/2022	14	0.007%	0.0009
4000465177	22798	28,373	6/27/2022	7/11/2022	14	0.007%	0.0010
4000465182	107810	1,000	6/27/2022	7/11/2022	14	0.000%	0.0000
4000465199	145207	500	6/27/2022	7/11/2022	14	0.000%	0.0000
4000465263	26363	2,853	6/28/2022	7/12/2022	14	0.001%	0.0001
4000465246	132321	3,823	6/28/2022	7/12/2022	14	0.001%	0.0001
4000465359	14463	3,976	6/30/2022	7/14/2022	14	0.001%	0.0001
4000465370	30475	47,846	6/30/2022	7/14/2022	14	0.013%	0.0018
4000465371	30475	34,627	6/30/2022	7/14/2022	14	0.009%	0.0013
4000465372	30475	39,015	6/30/2022	7/14/2022	14	0.010%	0.0014
4000465329	142681	129,874	6/30/2022	7/14/2022	14	0.034%	0.0048
4000465443	26323	21,016	7/1/2022	7/15/2022	14	0.006%	0.0008
4000465447	26639	9,113	7/1/2022	7/15/2022	14	0.002%	0.0003
4000465449	27162	24,944	7/1/2022	7/15/2022	14	0.007%	0.0009
4000465459	32510	3,488	7/1/2022	7/15/2022	14	0.001%	0.0001
4000465463	34341	28,180	7/1/2022	7/15/2022	14	0.007%	0.0010
4000465468	130375	11,656	7/1/2022	7/15/2022	14	0.003%	0.0004
4000465387	26958	2,099	7/1/2022	7/15/2022	14	0.001%	0.0001
4000465392	100910	1,238	7/1/2022	7/15/2022	14	0.000%	0.0000
4000465395	104872	45	7/1/2022	7/15/2022	14	0.000%	0.0000
4000465416	143436	836	7/1/2022	7/15/2022	14	0.000%	0.0000
4000465417	143477	1,162	7/1/2022	7/15/2022	14	0.000%	0.0000
4000465419	143880	1,800	7/1/2022	7/15/2022	14	0.000%	0.0001
4000465471	104872	42	7/5/2022	7/19/2022	14	0.000%	0.0000
4000465477	139128	524	7/5/2022	7/19/2022	14	0.000%	0.0000
4000465555	26493	29,165	7/7/2022	7/21/2022	14	0.008%	0.0011
4000465621	33770	154,928	7/8/2022	7/22/2022	14	0.041%	0.0057
4000465654	27389	2,645	7/11/2022	7/25/2022	14	0.001%	0.0001
4000465751	142942	1,768	7/13/2022	7/27/2022	14	0.000%	0.0001
4000465732	113747	3,500	7/13/2022	7/27/2022	14	0.001%	0.0001
4000465841	8392	21,487	7/15/2022	7/29/2022	14	0.006%	0.0008
4000465844	11577	3,885	7/15/2022	7/29/2022	14	0.001%	0.0001
4000465849	26323	17,200	7/15/2022	7/29/2022	14	0.005%	0.0006

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465872	135101	2,500	7/18/2022	8/1/2022	14	0.001%	0.0001
4000465914	33770	103,834	7/19/2022	8/2/2022	14	0.027%	0.0038
4000465916	32936	49,129	7/19/2022	8/2/2022	14	0.013%	0.0018
4000465917	32941	171,445	7/19/2022	8/2/2022	14	0.045%	0.0063
4000465918	32949	63,800	7/19/2022	8/2/2022	14	0.017%	0.0024
4000465919	32956	5,964	7/19/2022	8/2/2022	14	0.002%	0.0002
4000465923	33015	6,361	7/19/2022	8/2/2022	14	0.002%	0.0002
4000465924	33017	6,721	7/19/2022	8/2/2022	14	0.002%	0.0002
4000465935	33101	11,662	7/19/2022	8/2/2022	14	0.003%	0.0004
4000465936	33104	82,766	7/19/2022	8/2/2022	14	0.022%	0.0031
4000465937	33117	52,583	7/19/2022	8/2/2022	14	0.014%	0.0019
4000465940	33148	2,177	7/19/2022	8/2/2022	14	0.001%	0.0001
4000465948	116902	7,500	7/20/2022	8/3/2022	14	0.002%	0.0003
4000466004	11054	2,392	7/21/2022	8/4/2022	14	0.001%	0.0001
4000466010	26453	2,700	7/21/2022	8/4/2022	14	0.001%	0.0001
4000466012	26679	750	7/21/2022	8/4/2022	14	0.000%	0.0000
4000466020	130375	20,583	7/21/2022	8/4/2022	14	0.005%	0.0008
4000466104	27013	13,134	7/25/2022	8/8/2022	14	0.003%	0.0005
4000466090	121484	2,500	7/25/2022	8/8/2022	14	0.001%	0.0001
4000466157	8392	3,612	7/26/2022	8/9/2022	14	0.001%	0.0001
4000466138	143892	1,250	7/26/2022	8/9/2022	14	0.000%	0.0000
4000466140	144015	10,000	7/26/2022	8/9/2022	14	0.003%	0.0004
4000466191	25987	410	7/27/2022	8/10/2022	14	0.000%	0.0000
4000466236	26659	6,296	7/28/2022	8/11/2022	14	0.002%	0.0002
4000466246	33880	22,037	7/28/2022	8/11/2022	14	0.006%	0.0008
4000466216	124628	20,380	7/28/2022	8/11/2022	14	0.005%	0.0008
4000466218	134862	86,588	7/28/2022	8/11/2022	14	0.023%	0.0032
4000466292	13911	93,285	7/29/2022	8/12/2022	14	0.025%	0.0034
4000466295	24211	8,636	7/29/2022	8/12/2022	14	0.002%	0.0003
4000466305	26490	6,299	7/29/2022	8/12/2022	14	0.002%	0.0002
4000466310	27162	14,145	7/29/2022	8/12/2022	14	0.004%	0.0005
4000466327	32875	2,800	7/29/2022	8/12/2022	14	0.001%	0.0001
4000466256	6396	603	7/29/2022	8/12/2022	14	0.000%	0.0000
4000466259	15871	4,579	7/29/2022	8/12/2022	14	0.001%	0.0002
4000466275	135057	1,614	7/29/2022	8/12/2022	14	0.000%	0.0001
4000466286	144741	1,546	7/29/2022	8/12/2022	14	0.000%	0.0001
4000466381	26604	8,045	8/1/2022	8/15/2022	14	0.002%	0.0003
4000466409	33033	90,005	8/1/2022	8/15/2022	14	0.024%	0.0033
4000466436	26659	2,244	8/2/2022	8/16/2022	14	0.001%	0.0001
4000466442	100103	197	8/3/2022	8/17/2022	14	0.000%	0.0000
4000466440	132103	11,120	8/3/2022	8/17/2022	14	0.003%	0.0004
4000466513	25173	5,280	8/4/2022	8/18/2022	14	0.001%	0.0002
4000466516	27482	405	8/4/2022	8/18/2022	14	0.000%	0.0000
4000466519	30068	1,625	8/4/2022	8/18/2022	14	0.000%	0.0001
4000466490	15871	4,918	8/4/2022	8/18/2022	14	0.001%	0.0002
4000466501	123915	750	8/4/2022	8/18/2022	14	0.000%	0.0000
4000466506	144567	1,110	8/4/2022	8/18/2022	14	0.000%	0.0000
4000466509	145268	35,181	8/4/2022	8/18/2022	14	0.009%	0.0013
4000466526	4502	1,728	8/5/2022	8/19/2022	14	0.000%	0.0001
4000466533	104872	43	8/5/2022	8/19/2022	14	0.000%	0.0000
4000466541	139713	38,310	8/5/2022	8/19/2022	14	0.010%	0.0014
4000466550	143270	197	8/5/2022	8/19/2022	14	0.000%	0.0000
4000466602	26363	11,842	8/8/2022	8/22/2022	14	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466607	26643	753	8/8/2022	8/22/2022	14	0.000%	0.0000
4000466610	28619	1,672	8/8/2022	8/22/2022	14	0.000%	0.0001
4000466627	139128	697	8/9/2022	8/23/2022	14	0.000%	0.0000
4000466629	142402	247,867	8/9/2022	8/23/2022	14	0.065%	0.0092
4000466749	11426	3,326	8/11/2022	8/25/2022	14	0.001%	0.0001
4000466757	25808	1,500	8/11/2022	8/25/2022	14	0.000%	0.0001
4000466761	30475	49,771	8/11/2022	8/25/2022	14	0.013%	0.0018
4000466762	30475	33,299	8/11/2022	8/25/2022	14	0.009%	0.0012
4000466763	30475	39,719	8/11/2022	8/25/2022	14	0.010%	0.0015
4000466729	101853	10,552	8/11/2022	8/25/2022	14	0.003%	0.0004
4000466735	135488	30,394	8/11/2022	8/25/2022	14	0.008%	0.0011
4000466740	143436	836	8/11/2022	8/25/2022	14	0.000%	0.0000
4000466812	33770	77,112	8/12/2022	8/26/2022	14	0.020%	0.0028
4000466821	137825	68	8/12/2022	8/26/2022	14	0.000%	0.0000
4000466776	104872	1,844	8/12/2022	8/26/2022	14	0.000%	0.0001
4000466781	113529	76	8/12/2022	8/26/2022	14	0.000%	0.0000
4000466786	126928	81	8/12/2022	8/26/2022	14	0.000%	0.0000
4000466793	143111	2,000	8/12/2022	8/26/2022	14	0.001%	0.0001
4000466851	124628	49,188	8/15/2022	8/29/2022	14	0.013%	0.0018
4000466832	142942	6,695	8/15/2022	8/29/2022	14	0.002%	0.0002
4000466924	25599	10,251	8/17/2022	8/31/2022	14	0.003%	0.0004
4000466907	116384	53	8/17/2022	8/31/2022	14	0.000%	0.0000
4000466951	126928	27	8/18/2022	9/1/2022	14	0.000%	0.0000
4000466954	132914	99,689	8/18/2022	9/1/2022	14	0.026%	0.0037
4000467031	137825	993	8/19/2022	9/2/2022	14	0.000%	0.0000
4000466977	29254	1,937	8/19/2022	9/2/2022	14	0.001%	0.0001
4000466979	101853	29,625	8/19/2022	9/2/2022	14	0.008%	0.0011
4000466995	141583	79	8/19/2022	9/2/2022	14	0.000%	0.0000
4000467117	108619	2,000	8/24/2022	9/7/2022	14	0.001%	0.0001
4000467121	118973	1,500	8/24/2022	9/7/2022	14	0.000%	0.0001
4000467187	26453	64,195	8/25/2022	9/8/2022	14	0.017%	0.0024
4000467188	27994	4,730	8/25/2022	9/8/2022	14	0.001%	0.0002
4000467192	32875	2,450	8/25/2022	9/8/2022	14	0.001%	0.0001
4000467235	26363	2,117	8/26/2022	9/9/2022	14	0.001%	0.0001
4000467236	26642	603	8/26/2022	9/9/2022	14	0.000%	0.0000
4000467237	27013	20,616	8/26/2022	9/9/2022	14	0.005%	0.0008
4000467216	138862	411	8/26/2022	9/9/2022	14	0.000%	0.0000
4000467223	143314	4,756	8/26/2022	9/9/2022	14	0.001%	0.0002
4000467254	33027	3,830	8/26/2022	9/9/2022	14	0.001%	0.0001
4000467284	32875	1,000	8/29/2022	9/12/2022	14	0.000%	0.0000
4000467266	10439	770	8/29/2022	9/12/2022	14	0.000%	0.0000
4000467289	30494	29	8/30/2022	9/13/2022	14	0.000%	0.0000
4000467298	117302	5,000	8/30/2022	9/13/2022	14	0.001%	0.0002
4000467311	144487	54,923	8/30/2022	9/13/2022	14	0.014%	0.0020
4000467331	33009	506,254	8/30/2022	9/13/2022	14	0.134%	0.0187
4000467386	32245	1,312	8/31/2022	9/14/2022	14	0.000%	0.0000
4000467390	104725	500	8/31/2022	9/14/2022	14	0.000%	0.0000
4000467356	133915	600	8/31/2022	9/14/2022	14	0.000%	0.0000
4000467434	26643	2,197	9/1/2022	9/15/2022	14	0.001%	0.0001
4000467529	33770	6,883	9/2/2022	9/16/2022	14	0.002%	0.0003
4000467460	104872	57	9/2/2022	9/16/2022	14	0.000%	0.0000
4000467480	142002	7,696	9/2/2022	9/16/2022	14	0.002%	0.0003
4000467495	143880	1,800	9/2/2022	9/16/2022	14	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467506	144927	6,000	9/2/2022	9/16/2022	14	0.002%	0.0002
4000467512	145245	11,043	9/2/2022	9/16/2022	14	0.003%	0.0004
4000467539	103278	250	9/6/2022	9/20/2022	14	0.000%	0.0000
4000467580	28619	16,576	9/7/2022	9/21/2022	14	0.004%	0.0006
4000467583	34173	6,417	9/7/2022	9/21/2022	14	0.002%	0.0002
4000467563	6396	400	9/7/2022	9/21/2022	14	0.000%	0.0000
4000467565	34888	20	9/7/2022	9/21/2022	14	0.000%	0.0000
4000467658	27013	1,746	9/9/2022	9/23/2022	14	0.000%	0.0001
4000467686	135537	23,420	9/12/2022	9/26/2022	14	0.006%	0.0009
4000467701	11536	2,955	9/13/2022	9/27/2022	14	0.001%	0.0001
4000467695	142942	7,375	9/13/2022	9/27/2022	14	0.002%	0.0003
4000467728	125829	1,250	9/14/2022	9/28/2022	14	0.000%	0.0000
4000467731	134171	2,500	9/14/2022	9/28/2022	14	0.001%	0.0001
4000467820	26679	2,063	9/15/2022	9/29/2022	14	0.001%	0.0001
4000467870	26639	4,928	9/16/2022	9/30/2022	14	0.001%	0.0002
4000467874	30252	9,576	9/16/2022	9/30/2022	14	0.003%	0.0004
4000467903	24211	6,509	9/19/2022	10/3/2022	14	0.002%	0.0002
4000467889	36413	23,800	9/19/2022	10/3/2022	14	0.006%	0.0009
4000467893	124628	7,921	9/19/2022	10/3/2022	14	0.002%	0.0003
4000467916	103131	2,210	9/20/2022	10/4/2022	14	0.001%	0.0001
4000467917	104872	720	9/20/2022	10/4/2022	14	0.000%	0.0000
4000467925	142002	765	9/20/2022	10/4/2022	14	0.000%	0.0000
4000468080	27068	1,140	9/23/2022	10/7/2022	14	0.000%	0.0000
4000468028	9145	9,950	9/23/2022	10/7/2022	14	0.003%	0.0004
4000468048	126928	30	9/23/2022	10/7/2022	14	0.000%	0.0000
4000468051	132321	3,823	9/23/2022	10/7/2022	14	0.001%	0.0001
4000468054	137757	42,077	9/23/2022	10/7/2022	14	0.011%	0.0016
4000468149	11304	4,775	9/27/2022	10/11/2022	14	0.001%	0.0002
4000468159	27389	2,358	9/27/2022	10/11/2022	14	0.001%	0.0001
4000468160	28619	560	9/27/2022	10/11/2022	14	0.000%	0.0000
4000468134	104872	74	9/27/2022	10/11/2022	14	0.000%	0.0000
4000468139	124628	32,371	9/27/2022	10/11/2022	14	0.009%	0.0012
4000468145	144178	18,900	9/27/2022	10/11/2022	14	0.005%	0.0007
4000468165	32961	41,792	9/27/2022	10/11/2022	14	0.011%	0.0015
4000468166	32968	8,653	9/27/2022	10/11/2022	14	0.002%	0.0003
4000468168	32994	795	9/27/2022	10/11/2022	14	0.000%	0.0000
4000468171	33027	3,830	9/27/2022	10/11/2022	14	0.001%	0.0001
4000468178	33092	21,825	9/27/2022	10/11/2022	14	0.006%	0.0008
4000468179	33095	750	9/27/2022	10/11/2022	14	0.000%	0.0000
4000468181	33101	11,818	9/27/2022	10/11/2022	14	0.003%	0.0004
4000468183	33107	20,230	9/27/2022	10/11/2022	14	0.005%	0.0007
4000468184	33115	1,597	9/27/2022	10/11/2022	14	0.000%	0.0001
4000468188	33125	3,064	9/27/2022	10/11/2022	14	0.001%	0.0001
4000468190	33141	8,546	9/27/2022	10/11/2022	14	0.002%	0.0003
4000468247	26588	15,285	9/28/2022	10/12/2022	14	0.004%	0.0006
4000468224	129491	3,000	9/28/2022	10/12/2022	14	0.001%	0.0001
4000468294	24259	5,011	9/29/2022	10/13/2022	14	0.001%	0.0002
4000468284	144581	16,429	9/29/2022	10/13/2022	14	0.004%	0.0006
4000468399	11577	9,240	9/30/2022	10/14/2022	14	0.002%	0.0003
4000468403	24113	20,220	9/30/2022	10/14/2022	14	0.005%	0.0007
4000468406	25987	1,800	9/30/2022	10/14/2022	14	0.000%	0.0001
4000468407	26213	13,708	9/30/2022	10/14/2022	14	0.004%	0.0005
4000468409	27013	27,174	9/30/2022	10/14/2022	14	0.007%	0.0010

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468420	34531	17,919	9/30/2022	10/14/2022	14	0.005%	0.0007
4000468422	34937	12,000	9/30/2022	10/14/2022	14	0.003%	0.0004
4000468319	30580	3,332	9/30/2022	10/14/2022	14	0.001%	0.0001
4000468321	35151	4,500	9/30/2022	10/14/2022	14	0.001%	0.0002
4000468322	102473	650	9/30/2022	10/14/2022	14	0.000%	0.0000
4000468326	106674	6,073	9/30/2022	10/14/2022	14	0.002%	0.0002
4000468339	126715	10,500	9/30/2022	10/14/2022	14	0.003%	0.0004
4000468344	134906	3,900	9/30/2022	10/14/2022	14	0.001%	0.0001
4000468354	142162	11,000	9/30/2022	10/14/2022	14	0.003%	0.0004
4000468376	144410	2,850	9/30/2022	10/14/2022	14	0.001%	0.0001
4000468386	144927	6,000	9/30/2022	10/14/2022	14	0.002%	0.0002
4000468394	145341	4,688	9/30/2022	10/14/2022	14	0.001%	0.0002
4000468445	11427	19,350	10/3/2022	10/17/2022	14	0.005%	0.0007
4000468464	27389	2,300	10/3/2022	10/17/2022	14	0.001%	0.0001
4000468436	143400	3,000	10/3/2022	10/17/2022	14	0.001%	0.0001
4000468478	8392	1,592	10/4/2022	10/18/2022	14	0.000%	0.0001
4000468499	106699	7,530	10/5/2022	10/19/2022	14	0.002%	0.0003
4000468492	142942	147	10/5/2022	10/19/2022	14	0.000%	0.0000
4000468531	30068	423	10/6/2022	10/20/2022	14	0.000%	0.0000
4000468512	142681	118,420	10/6/2022	10/20/2022	14	0.031%	0.0044
4000468585	24191	14,341	10/7/2022	10/21/2022	14	0.004%	0.0005
4000468591	27162	3,255	10/7/2022	10/21/2022	14	0.001%	0.0001
4000468605	32875	5,300	10/7/2022	10/21/2022	14	0.001%	0.0002
4000468537	4502	9,798	10/7/2022	10/21/2022	14	0.003%	0.0004
4000468577	145193	2,260	10/7/2022	10/21/2022	14	0.001%	0.0001
4000468664	30252	17,200	10/11/2022	10/25/2022	14	0.005%	0.0006
4000468619	32869	8,500	10/11/2022	10/25/2022	14	0.002%	0.0003
4000468732	30124	690	10/12/2022	10/26/2022	14	0.000%	0.0000
4000468741	137825	9	10/12/2022	10/26/2022	14	0.000%	0.0000
4000468704	137958	1,000	10/12/2022	10/26/2022	14	0.000%	0.0000
4000468673	101122	3,600	10/12/2022	10/26/2022	14	0.001%	0.0001
4000468766	11054	7,248	10/13/2022	10/27/2022	14	0.002%	0.0003
4000468768	18275	10,139	10/13/2022	10/27/2022	14	0.003%	0.0004
4000468773	26604	48,105	10/13/2022	10/27/2022	14	0.013%	0.0018
4000468774	26639	6,210	10/13/2022	10/27/2022	14	0.002%	0.0002
4000468778	30475	64,209	10/13/2022	10/27/2022	14	0.017%	0.0024
4000468743	15871	2,518	10/13/2022	10/27/2022	14	0.001%	0.0001
4000468748	108083	57,857	10/13/2022	10/27/2022	14	0.015%	0.0021
4000468819	9121	7,400	10/14/2022	10/28/2022	14	0.002%	0.0003
4000468826	26493	75	10/14/2022	10/28/2022	14	0.000%	0.0000
4000468813	144422	19,139	10/14/2022	10/28/2022	14	0.005%	0.0007
4000468879	25809	3,709	10/17/2022	10/31/2022	14	0.001%	0.0001
4000468893	135537	84,315	10/17/2022	10/31/2022	14	0.022%	0.0031
4000468866	142942	5,055	10/17/2022	10/31/2022	14	0.001%	0.0002
4000468869	145222	736	10/17/2022	10/31/2022	14	0.000%	0.0000
4000468907	104872	1,095	10/18/2022	11/1/2022	14	0.000%	0.0000
4000468967	33956	2,011	10/19/2022	11/2/2022	14	0.001%	0.0001
4000468984	32976	2,818	10/19/2022	11/2/2022	14	0.001%	0.0001
4000469025	33127	38,115	10/19/2022	11/2/2022	14	0.010%	0.0014
4000469063	28619	44,252	10/20/2022	11/3/2022	14	0.012%	0.0016
4000469074	137825	471	10/20/2022	11/3/2022	14	0.000%	0.0000
4000469146	141583	158	10/24/2022	11/7/2022	14	0.000%	0.0000
4000469154	144581	10,872	10/24/2022	11/7/2022	14	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469199	26381	1,520	10/25/2022	11/8/2022	14	0.000%	0.0001
4000469201	28084	3,895	10/25/2022	11/8/2022	14	0.001%	0.0001
4000469202	34348	525	10/25/2022	11/8/2022	14	0.000%	0.0000
4000469169	103008	127	10/25/2022	11/8/2022	14	0.000%	0.0000
4000469179	142681	40,846	10/25/2022	11/8/2022	14	0.011%	0.0015
4000469185	145222	8,326	10/25/2022	11/8/2022	14	0.002%	0.0003
4000469167	114121	3,415	10/25/2022	11/8/2022	14	0.001%	0.0001
4000469247	30475	4,795	10/26/2022	11/9/2022	14	0.001%	0.0002
4000469224	142681	133,644	10/26/2022	11/9/2022	14	0.035%	0.0049
4000469304	26453	8,920	10/27/2022	11/10/2022	14	0.002%	0.0003
4000469322	125016	493	10/27/2022	11/10/2022	14	0.000%	0.0000
4000469266	26130	80,804	10/27/2022	11/10/2022	14	0.021%	0.0030
4000469277	126928	93	10/27/2022	11/10/2022	14	0.000%	0.0000
4000469442	26382	983	10/31/2022	11/14/2022	14	0.000%	0.0000
4000469450	32897	4,000	10/31/2022	11/14/2022	14	0.001%	0.0001
4000469404	15871	11,168	10/31/2022	11/14/2022	14	0.003%	0.0004
4000469409	103131	1,768	10/31/2022	11/14/2022	14	0.000%	0.0001
4000469415	123915	545	10/31/2022	11/14/2022	14	0.000%	0.0000
4000469416	126928	401	10/31/2022	11/14/2022	14	0.000%	0.0000
4000469468	9891	3,432	11/1/2022	11/15/2022	14	0.001%	0.0001
4000469476	26381	1,280	11/1/2022	11/15/2022	14	0.000%	0.0000
4000469465	142942	11,031	11/1/2022	11/15/2022	14	0.003%	0.0004
4000469534	27013	8,620	11/2/2022	11/16/2022	14	0.002%	0.0003
4000469590	30068	358	11/3/2022	11/17/2022	14	0.000%	0.0000
4000469577	145341	4,688	11/3/2022	11/17/2022	14	0.001%	0.0002
4000469612	103131	583	11/4/2022	11/18/2022	14	0.000%	0.0000
4000469679	8392	11,878	11/7/2022	11/21/2022	14	0.003%	0.0004
4000469670	141583	639	11/7/2022	11/21/2022	14	0.000%	0.0000
4000469715	107047	16,192	11/9/2022	11/23/2022	14	0.004%	0.0006
4000469892	24211	5,101	11/15/2022	11/29/2022	14	0.001%	0.0002
4000469882	142942	6,943	11/15/2022	11/29/2022	14	0.002%	0.0003
4000469925	26016	2,706	11/16/2022	11/30/2022	14	0.001%	0.0001
4000469927	26299	643	11/16/2022	11/30/2022	14	0.000%	0.0000
4000469953	34616	12,580	11/16/2022	11/30/2022	14	0.003%	0.0005
4000469955	135537	12,688	11/16/2022	11/30/2022	14	0.003%	0.0005
4000469916	142681	183,561	11/16/2022	11/30/2022	14	0.048%	0.0068
4000469956	32976	3,927	11/16/2022	11/30/2022	14	0.001%	0.0001
4000469980	11536	6,670	11/17/2022	12/1/2022	14	0.002%	0.0002
4000469989	33956	2,231	11/17/2022	12/1/2022	14	0.001%	0.0001
4000470033	25131	380	11/18/2022	12/2/2022	14	0.000%	0.0000
4000470051	134272	3,051	11/18/2022	12/2/2022	14	0.001%	0.0001
4000470000	101853	36,205	11/18/2022	12/2/2022	14	0.010%	0.0013
4000470063	124584	344	11/21/2022	12/5/2022	14	0.000%	0.0000
4000470081	145222	1,012	11/21/2022	12/5/2022	14	0.000%	0.0000
4000470201	26577	4,000	11/23/2022	12/7/2022	14	0.001%	0.0001
4000470202	26659	2,244	11/23/2022	12/7/2022	14	0.001%	0.0001
4000470205	28084	3,515	11/23/2022	12/7/2022	14	0.001%	0.0001
4000470220	33956	5,358	11/23/2022	12/7/2022	14	0.001%	0.0002
4000470147	4765	2,000	11/23/2022	12/7/2022	14	0.001%	0.0001
4000470150	15871	7,542	11/23/2022	12/7/2022	14	0.002%	0.0003
4000470154	27094	883	11/23/2022	12/7/2022	14	0.000%	0.0000
4000470165	134862	544,087	11/23/2022	12/7/2022	14	0.144%	0.0201
4000470178	143577	5,188	11/23/2022	12/7/2022	14	0.001%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470183	144084	13,000	11/23/2022	12/7/2022	14	0.003%	0.0005
4000470189	145107	6,994	11/23/2022	12/7/2022	14	0.002%	0.0003
4000470191	145251	5,994	11/23/2022	12/7/2022	14	0.002%	0.0002
4000470192	145258	19,989	11/23/2022	12/7/2022	14	0.005%	0.0007
4000470257	25708	2,330	11/28/2022	12/12/2022	14	0.001%	0.0001
4000470230	4208	2,549	11/28/2022	12/12/2022	14	0.001%	0.0001
4000470240	143072	30,349	11/28/2022	12/12/2022	14	0.008%	0.0011
4000470297	9891	4,732	11/29/2022	12/13/2022	14	0.001%	0.0002
4000470286	142942	6,248	11/29/2022	12/13/2022	14	0.002%	0.0002
4000470292	145143	16,249	11/29/2022	12/13/2022	14	0.004%	0.0006
4000470360	26363	2,130	11/30/2022	12/14/2022	14	0.001%	0.0001
4000470444	32897	6,750	12/1/2022	12/15/2022	14	0.002%	0.0002
4000470402	112317	72,000	12/1/2022	12/15/2022	14	0.019%	0.0027
4000470427	144454	2,000	12/1/2022	12/15/2022	14	0.001%	0.0001
4000470475	141831	11,880	12/2/2022	12/16/2022	14	0.003%	0.0004
4000470479	142587	260	12/2/2022	12/16/2022	14	0.000%	0.0000
4000470483	142874	12,939	12/2/2022	12/16/2022	14	0.003%	0.0005
4000470492	143400	3,000	12/2/2022	12/16/2022	14	0.001%	0.0001
4000470496	143880	1,800	12/2/2022	12/16/2022	14	0.000%	0.0001
4000470500	144410	2,850	12/2/2022	12/16/2022	14	0.001%	0.0001
4000470507	144927	6,000	12/2/2022	12/16/2022	14	0.002%	0.0002
4000470517	145245	11,043	12/2/2022	12/16/2022	14	0.003%	0.0004
4000470566	10630	1,200	12/5/2022	12/19/2022	14	0.000%	0.0000
4000470597	124628	16,552	12/6/2022	12/20/2022	14	0.004%	0.0006
4000470574	101853	6,557	12/6/2022	12/20/2022	14	0.002%	0.0002
4000470576	104872	887	12/6/2022	12/20/2022	14	0.000%	0.0000
4000470723	11577	3,570	12/9/2022	12/23/2022	14	0.001%	0.0001
4000470727	26323	2,580	12/9/2022	12/23/2022	14	0.001%	0.0001
4000470694	6031	10,220	12/9/2022	12/23/2022	14	0.003%	0.0004
4000470707	142942	37,602	12/9/2022	12/23/2022	14	0.010%	0.0014
4000470795	8392	9,551	12/13/2022	12/27/2022	14	0.003%	0.0004
4000470796	9891	9,269	12/13/2022	12/27/2022	14	0.002%	0.0003
4000470803	27994	3,190	12/13/2022	12/27/2022	14	0.001%	0.0001
4000470791	144519	65,843	12/13/2022	12/27/2022	14	0.017%	0.0024
4000470854	26381	640	12/14/2022	12/28/2022	14	0.000%	0.0000
4000470862	32538	119	12/14/2022	12/28/2022	14	0.000%	0.0000
4000470809	4502	717	12/14/2022	12/28/2022	14	0.000%	0.0000
4000470817	104872	3,030	12/14/2022	12/28/2022	14	0.001%	0.0001
4000470831	142942	1,074	12/14/2022	12/28/2022	14	0.000%	0.0000
4000470885	118807	26	12/15/2022	12/29/2022	14	0.000%	0.0000
4000470902	145555	2,500	12/15/2022	12/29/2022	14	0.001%	0.0001
4000470938	124298	1,191	12/16/2022	12/30/2022	14	0.000%	0.0000
4000470941	126047	1,172	12/16/2022	12/30/2022	14	0.000%	0.0000
4000470943	129783	660	12/16/2022	12/30/2022	14	0.000%	0.0000
4000470957	141831	11,880	12/16/2022	12/30/2022	14	0.003%	0.0004
4000470962	142787	10,565	12/16/2022	12/30/2022	14	0.003%	0.0004
4000470963	142874	12,939	12/16/2022	12/30/2022	14	0.003%	0.0005
4000470966	143072	34,164	12/16/2022	12/30/2022	14	0.009%	0.0013
4000470969	143502	417	12/16/2022	12/30/2022	14	0.000%	0.0000
4000470970	143577	8,685	12/16/2022	12/30/2022	14	0.002%	0.0003
4000470976	144410	2,850	12/16/2022	12/30/2022	14	0.001%	0.0001
4000470984	144881	16,893	12/16/2022	12/30/2022	14	0.004%	0.0006
4000470993	145245	11,043	12/16/2022	12/30/2022	14	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471080	8392	38,939	12/20/2022	1/3/2023	14	0.010%	0.0014
4000471092	26604	4,990	12/20/2022	1/3/2023	14	0.001%	0.0002
4000471093	26639	17,415	12/20/2022	1/3/2023	14	0.005%	0.0006
4000471096	27962	2,394	12/20/2022	1/3/2023	14	0.001%	0.0001
4000471101	32356	816	12/20/2022	1/3/2023	14	0.000%	0.0000
4000471071	142942	13,557	12/20/2022	1/3/2023	14	0.004%	0.0005
4000471076	145211	1,613	12/20/2022	1/3/2023	14	0.000%	0.0001
4000471109	15871	1,837	12/21/2022	1/4/2023	14	0.000%	0.0001
4000471120	124628	49,632	12/21/2022	1/4/2023	14	0.013%	0.0018
4000471122	130125	7,500	12/21/2022	1/4/2023	14	0.002%	0.0003
4000471126	143243	35,904	12/21/2022	1/4/2023	14	0.009%	0.0013
4000471203	25083	605	12/22/2022	1/5/2023	14	0.000%	0.0000
4000471207	27982	1,660	12/22/2022	1/5/2023	14	0.000%	0.0001
4000471176	22902	17,679	12/22/2022	1/5/2023	14	0.005%	0.0007
4000471190	134862	86,989	12/22/2022	1/5/2023	14	0.023%	0.0032
4000471193	143072	3,638	12/22/2022	1/5/2023	14	0.001%	0.0001
4000471195	143727	169,979	12/22/2022	1/5/2023	14	0.045%	0.0063
4000471197	144561	7,150	12/22/2022	1/5/2023	14	0.002%	0.0003
4000471200	145453	44,906	12/22/2022	1/5/2023	14	0.012%	0.0017
4000471251	26312	33,963	12/23/2022	1/6/2023	14	0.009%	0.0013
4000471259	32537	3,280	12/23/2022	1/6/2023	14	0.001%	0.0001
4000471225	27026	13,800	12/23/2022	1/6/2023	14	0.004%	0.0005
4000471232	139733	568	12/23/2022	1/6/2023	14	0.000%	0.0000
4000471234	142942	28,668	12/23/2022	1/6/2023	14	0.008%	0.0011
4000471275	142942	697	12/27/2022	1/10/2023	14	0.000%	0.0000
4000471334	34616	2,383	12/28/2022	1/11/2023	14	0.001%	0.0001
4000471371	11304	3,300	12/29/2022	1/12/2023	14	0.001%	0.0001
4000471383	25029	520	12/29/2022	1/12/2023	14	0.000%	0.0000
4000471384	25272	2,400	12/29/2022	1/12/2023	14	0.001%	0.0001
4000471344	18785	23,018	12/29/2022	1/12/2023	14	0.006%	0.0008
4000471363	144262	6,937	12/29/2022	1/12/2023	14	0.002%	0.0003
4000471485	24113	5,412	12/30/2022	1/13/2023	14	0.001%	0.0002
4000471492	26604	3,855	12/30/2022	1/13/2023	14	0.001%	0.0001
4000471509	32537	1,400	12/30/2022	1/13/2023	14	0.000%	0.0001
4000471512	33924	143,848	12/30/2022	1/13/2023	14	0.038%	0.0053
4000471421	15871	21,175	12/30/2022	1/13/2023	14	0.006%	0.0008
4000471425	26958	10,926	12/30/2022	1/13/2023	14	0.003%	0.0004
4000471451	143340	8,422	12/30/2022	1/13/2023	14	0.002%	0.0003
4000471463	143962	191,100	12/30/2022	1/13/2023	14	0.050%	0.0071
4000471471	145181	1,350	12/30/2022	1/13/2023	14	0.000%	0.0000
4000471473	145341	4,688	12/30/2022	1/13/2023	14	0.001%	0.0002
4000471475	145480	1,200	12/30/2022	1/13/2023	14	0.000%	0.0000
4000459561	34393	6,450	1/3/2022	1/18/2022	15	0.002%	0.0003
4000459654	34531	3,060	1/6/2022	1/21/2022	15	0.001%	0.0001
4000459627	138862	448	1/6/2022	1/21/2022	15	0.000%	0.0000
4000459714	11305	10,728	1/10/2022	1/25/2022	15	0.003%	0.0004
4000459720	24385	1,967	1/10/2022	1/25/2022	15	0.001%	0.0001
4000459722	25379	1,197	1/10/2022	1/25/2022	15	0.000%	0.0000
4000459728	26356	1,856	1/10/2022	1/25/2022	15	0.000%	0.0001
4000459731	26588	11,355	1/10/2022	1/25/2022	15	0.003%	0.0004
4000459734	26667	367	1/10/2022	1/25/2022	15	0.000%	0.0000
4000459771	125016	717	1/11/2022	1/26/2022	15	0.000%	0.0000
4000459742	14875	4,127	1/11/2022	1/26/2022	15	0.001%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459795	26493	10,541	1/12/2022	1/27/2022	15	0.003%	0.0004
4000459861	11631	11,000	1/13/2022	1/28/2022	15	0.003%	0.0004
4000459839	139503	47,642	1/13/2022	1/28/2022	15	0.013%	0.0019
4000459844	143340	600	1/13/2022	1/28/2022	15	0.000%	0.0000
4000459847	143622	12,000	1/13/2022	1/28/2022	15	0.003%	0.0005
4000459958	22798	12,189	1/18/2022	2/2/2022	15	0.003%	0.0005
4000459979	144668	1,552	1/18/2022	2/2/2022	15	0.000%	0.0001
4000460030	144658	50	1/19/2022	2/3/2022	15	0.000%	0.0000
4000460095	32875	4,050	1/20/2022	2/4/2022	15	0.001%	0.0002
4000460149	9673	14,900	1/24/2022	2/8/2022	15	0.004%	0.0006
4000460153	25599	9,114	1/24/2022	2/8/2022	15	0.002%	0.0004
4000460163	27389	46,978	1/24/2022	2/8/2022	15	0.012%	0.0019
4000460134	116902	2,363	1/24/2022	2/8/2022	15	0.001%	0.0001
4000460176	33005	3,423	1/24/2022	2/8/2022	15	0.001%	0.0001
4000460194	33032	3,307	1/24/2022	2/8/2022	15	0.001%	0.0001
4000460202	33045	68,836	1/24/2022	2/8/2022	15	0.018%	0.0027
4000460273	125016	3,227	1/25/2022	2/9/2022	15	0.001%	0.0001
4000460235	112103	77,752	1/25/2022	2/9/2022	15	0.021%	0.0031
4000460248	144786	15,000	1/25/2022	2/9/2022	15	0.004%	0.0006
4000460297	26301	1,198	1/26/2022	2/10/2022	15	0.000%	0.0000
4000460441	34531	9,112	1/27/2022	2/11/2022	15	0.002%	0.0004
4000460448	130375	33,335	1/27/2022	2/11/2022	15	0.009%	0.0013
4000460314	22798	22,998	1/27/2022	2/11/2022	15	0.006%	0.0009
4000460315	22798	34,308	1/27/2022	2/11/2022	15	0.009%	0.0014
4000460341	32955	12,397	1/27/2022	2/11/2022	15	0.003%	0.0005
4000460352	33033	86,011	1/27/2022	2/11/2022	15	0.023%	0.0034
4000460355	33069	80,971	1/27/2022	2/11/2022	15	0.021%	0.0032
4000460387	33113	14,355	1/27/2022	2/11/2022	15	0.004%	0.0006
4000460405	33133	9,670	1/27/2022	2/11/2022	15	0.003%	0.0004
4000460602	26362	3,400	1/31/2022	2/15/2022	15	0.001%	0.0001
4000460610	27512	1,274	1/31/2022	2/15/2022	15	0.000%	0.0001
4000460575	141583	316	1/31/2022	2/15/2022	15	0.000%	0.0000
4000460663	8539	12,800	2/1/2022	2/16/2022	15	0.003%	0.0005
4000460619	11427	3,400	2/1/2022	2/16/2022	15	0.001%	0.0001
4000460633	136045	42,000	2/1/2022	2/16/2022	15	0.011%	0.0017
4000460739	9891	4,465	2/3/2022	2/18/2022	15	0.001%	0.0002
4000460834	24251	17,760	2/7/2022	2/22/2022	15	0.005%	0.0007
4000460823	144213	20,000	2/7/2022	2/22/2022	15	0.005%	0.0008
4000461064	26299	3,502	2/14/2022	3/1/2022	15	0.001%	0.0001
4000461147	25708	930	2/16/2022	3/3/2022	15	0.000%	0.0000
4000461133	141826	18,620	2/16/2022	3/3/2022	15	0.005%	0.0007
4000461367	126165	4,535	2/23/2022	3/10/2022	15	0.001%	0.0002
4000461496	9891	520	2/28/2022	3/15/2022	15	0.000%	0.0000
4000461514	33770	13,490	2/28/2022	3/15/2022	15	0.004%	0.0005
4000461483	125742	4,331	2/28/2022	3/15/2022	15	0.001%	0.0002
4000461524	139487	316	3/1/2022	3/16/2022	15	0.000%	0.0000
4000461582	144031	1,403	3/2/2022	3/17/2022	15	0.000%	0.0001
4000461615	142942	5,109	3/3/2022	3/18/2022	15	0.001%	0.0002
4000461699	144172	300	3/7/2022	3/22/2022	15	0.000%	0.0000
4000461786	13911	2,470	3/10/2022	3/25/2022	15	0.001%	0.0001
4000461790	26493	279	3/10/2022	3/25/2022	15	0.000%	0.0000
4000461778	143457	40,000	3/10/2022	3/25/2022	15	0.011%	0.0016
4000461903	14463	26,248	3/15/2022	3/30/2022	15	0.007%	0.0010

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461926	130375	10,939	3/15/2022	3/30/2022	15	0.003%	0.0004
4000461895	144668	776	3/15/2022	3/30/2022	15	0.000%	0.0000
4000461965	103008	2,072	3/17/2022	4/1/2022	15	0.001%	0.0001
4000462059	103301	196	3/21/2022	4/5/2022	15	0.000%	0.0000
4000462190	26643	857	3/24/2022	4/8/2022	15	0.000%	0.0000
4000462268	26362	3,150	3/28/2022	4/12/2022	15	0.001%	0.0001
4000462246	108013	5,000	3/28/2022	4/12/2022	15	0.001%	0.0002
4000462301	11427	13,800	3/29/2022	4/13/2022	15	0.004%	0.0005
4000462303	24251	13,080	3/29/2022	4/13/2022	15	0.003%	0.0005
4000462315	135537	33,112	3/29/2022	4/13/2022	15	0.009%	0.0013
4000462392	28619	2,460	3/30/2022	4/14/2022	15	0.001%	0.0001
4000462327	102473	16,025	3/30/2022	4/14/2022	15	0.004%	0.0006
4000462411	30580	1,242	3/31/2022	4/15/2022	15	0.000%	0.0000
4000462586	144922	8,000	4/4/2022	4/19/2022	15	0.002%	0.0003
4000462615	27493	630	4/5/2022	4/20/2022	15	0.000%	0.0000
4000462634	13911	42,620	4/6/2022	4/21/2022	15	0.011%	0.0017
4000462636	25987	400	4/6/2022	4/21/2022	15	0.000%	0.0000
4000462677	24114	2,090	4/7/2022	4/22/2022	15	0.001%	0.0001
4000462757	144668	776	4/11/2022	4/26/2022	15	0.000%	0.0000
4000462862	125016	538	4/13/2022	4/28/2022	15	0.000%	0.0000
4000462896	11304	5,700	4/14/2022	4/29/2022	15	0.002%	0.0002
4000462926	34348	945	4/14/2022	4/29/2022	15	0.000%	0.0000
4000462933	134272	11,026	4/14/2022	4/29/2022	15	0.003%	0.0004
4000462943	139089	19	4/18/2022	5/3/2022	15	0.000%	0.0000
4000463027	130375	1,791	4/20/2022	5/5/2022	15	0.000%	0.0001
4000463036	124628	2,118	4/21/2022	5/6/2022	15	0.001%	0.0001
4000463178	34173	24,271	4/25/2022	5/10/2022	15	0.006%	0.0010
4000463163	143637	3,750	4/25/2022	5/10/2022	15	0.001%	0.0001
4000463187	139089	459	4/26/2022	5/11/2022	15	0.000%	0.0000
4000463297	24113	10,008	4/28/2022	5/13/2022	15	0.003%	0.0004
4000463258	107932	1,000	4/28/2022	5/13/2022	15	0.000%	0.0000
4000463496	144858	400	5/3/2022	5/18/2022	15	0.000%	0.0000
4000463633	142942	7,437	5/9/2022	5/24/2022	15	0.002%	0.0003
4000463714	13911	5,885	5/11/2022	5/26/2022	15	0.002%	0.0002
4000463731	125016	3,406	5/11/2022	5/26/2022	15	0.001%	0.0001
4000463732	126165	459	5/11/2022	5/26/2022	15	0.000%	0.0000
4000463687	25659	760	5/11/2022	5/26/2022	15	0.000%	0.0000
4000463738	25147	139,444	5/12/2022	5/27/2022	15	0.037%	0.0055
4000463879	8998	3,214	5/16/2022	5/31/2022	15	0.001%	0.0001
4000463887	25131	1,520	5/16/2022	5/31/2022	15	0.000%	0.0001
4000463888	25809	1,515	5/16/2022	5/31/2022	15	0.000%	0.0001
4000463891	26299	3,920	5/16/2022	5/31/2022	15	0.001%	0.0002
4000463894	26643	1,556	5/16/2022	5/31/2022	15	0.000%	0.0001
4000463846	122519	5,000	5/16/2022	5/31/2022	15	0.001%	0.0002
4000463847	122604	1,000	5/16/2022	5/31/2022	15	0.000%	0.0000
4000463858	132321	104	5/16/2022	5/31/2022	15	0.000%	0.0000
4000463873	144860	3,000	5/16/2022	5/31/2022	15	0.001%	0.0001
4000463950	23681	2,122	5/18/2022	6/2/2022	15	0.001%	0.0001
4000463952	24885	3,225	5/18/2022	6/2/2022	15	0.001%	0.0001
4000464090	9891	4,291	5/23/2022	6/7/2022	15	0.001%	0.0002
4000464095	126165	24,627	5/23/2022	6/7/2022	15	0.006%	0.0010
4000464126	28619	10,877	5/24/2022	6/8/2022	15	0.003%	0.0004
4000464132	34779	16,900	5/24/2022	6/8/2022	15	0.004%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464176	32808	770	5/25/2022	6/9/2022	15	0.000%	0.0000
4000464194	142576	24,000	5/26/2022	6/10/2022	15	0.006%	0.0009
4000464412	33770	11,953	6/1/2022	6/16/2022	15	0.003%	0.0005
4000464432	134906	3,900	6/2/2022	6/17/2022	15	0.001%	0.0002
4000464447	142874	12,939	6/2/2022	6/17/2022	15	0.003%	0.0005
4000464457	144015	10,000	6/2/2022	6/17/2022	15	0.003%	0.0004
4000464458	144344	5,000	6/2/2022	6/17/2022	15	0.001%	0.0002
4000464570	28619	13,428	6/6/2022	6/21/2022	15	0.004%	0.0005
4000464598	27068	2,280	6/7/2022	6/22/2022	15	0.001%	0.0001
4000464604	30252	22,704	6/7/2022	6/22/2022	15	0.006%	0.0009
4000464627	143189	11,041	6/8/2022	6/23/2022	15	0.003%	0.0004
4000464668	26493	17,831	6/9/2022	6/24/2022	15	0.005%	0.0007
4000464673	34173	48,904	6/9/2022	6/24/2022	15	0.013%	0.0019
4000464764	25029	8,060	6/13/2022	6/28/2022	15	0.002%	0.0003
4000464770	26299	7,515	6/13/2022	6/28/2022	15	0.002%	0.0003
4000464775	26453	1,560	6/13/2022	6/28/2022	15	0.000%	0.0001
4000464814	28619	4,180	6/14/2022	6/29/2022	15	0.001%	0.0002
4000464852	26679	2,000	6/15/2022	6/30/2022	15	0.001%	0.0001
4000465059	9145	12,434	6/23/2022	7/8/2022	15	0.003%	0.0005
4000465209	24114	1,980	6/27/2022	7/12/2022	15	0.001%	0.0001
4000465216	25599	7,439	6/27/2022	7/12/2022	15	0.002%	0.0003
4000465229	34779	58,702	6/27/2022	7/12/2022	15	0.015%	0.0023
4000465230	126165	4,879	6/27/2022	7/12/2022	15	0.001%	0.0002
4000465181	104253	3,500	6/27/2022	7/12/2022	15	0.001%	0.0001
4000465175	134054	209,700	6/27/2022	7/12/2022	15	0.055%	0.0083
4000465261	25708	1,246	6/28/2022	7/13/2022	15	0.000%	0.0000
4000465268	28619	3,344	6/28/2022	7/13/2022	15	0.001%	0.0001
4000465245	128504	111	6/28/2022	7/13/2022	15	0.000%	0.0000
4000465281	142870	20,297	6/29/2022	7/14/2022	15	0.005%	0.0008
4000465310	129753	1,302	6/30/2022	7/15/2022	15	0.000%	0.0001
4000465519	11372	2,497	7/6/2022	7/21/2022	15	0.001%	0.0001
4000465518	145108	2,500	7/6/2022	7/21/2022	15	0.001%	0.0001
4000465550	13911	1,795	7/7/2022	7/22/2022	15	0.000%	0.0001
4000465658	125016	896	7/11/2022	7/26/2022	15	0.000%	0.0000
4000465727	11474	3,975	7/12/2022	7/27/2022	15	0.001%	0.0002
4000465730	28619	2,717	7/12/2022	7/27/2022	15	0.001%	0.0001
4000465721	142942	7,652	7/12/2022	7/27/2022	15	0.002%	0.0003
4000465881	10384	11,650	7/18/2022	8/2/2022	15	0.003%	0.0005
4000465875	142575	2,500	7/18/2022	8/2/2022	15	0.001%	0.0001
4000465922	32985	5,301	7/19/2022	8/3/2022	15	0.001%	0.0002
4000465927	33029	8,709	7/19/2022	8/3/2022	15	0.002%	0.0003
4000465928	33031	27,239	7/19/2022	8/3/2022	15	0.007%	0.0011
4000465930	33056	2,238	7/19/2022	8/3/2022	15	0.001%	0.0001
4000465933	33076	43,721	7/19/2022	8/3/2022	15	0.012%	0.0017
4000465938	33133	10,066	7/19/2022	8/3/2022	15	0.003%	0.0004
4000466159	11054	6,344	7/26/2022	8/10/2022	15	0.002%	0.0003
4000466152	144996	2,500	7/26/2022	8/10/2022	15	0.001%	0.0001
4000466154	145152	8,240	7/26/2022	8/10/2022	15	0.002%	0.0003
4000466155	145222	1,012	7/26/2022	8/10/2022	15	0.000%	0.0000
4000466240	27162	1,363	7/28/2022	8/12/2022	15	0.000%	0.0001
4000466382	26659	1,496	8/1/2022	8/16/2022	15	0.000%	0.0001
4000466392	32921	3,333	8/1/2022	8/16/2022	15	0.001%	0.0001
4000466417	33127	40,915	8/1/2022	8/16/2022	15	0.011%	0.0016

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466426	108934	500	8/2/2022	8/17/2022	15	0.000%	0.0000
4000466429	142942	6,424	8/2/2022	8/17/2022	15	0.002%	0.0003
4000466465	25173	9,539	8/3/2022	8/18/2022	15	0.003%	0.0004
4000466515	27068	10,830	8/4/2022	8/19/2022	15	0.003%	0.0004
4000466521	32808	2,090	8/4/2022	8/19/2022	15	0.001%	0.0001
4000466524	34658	2,500	8/4/2022	8/19/2022	15	0.001%	0.0001
4000466488	102473	6,121	8/4/2022	8/19/2022	15	0.002%	0.0002
4000466616	9891	2,594	8/9/2022	8/24/2022	15	0.001%	0.0001
4000466621	104872	776	8/9/2022	8/24/2022	15	0.000%	0.0000
4000466635	145049	10,000	8/9/2022	8/24/2022	15	0.003%	0.0004
4000466656	126604	3,600	8/10/2022	8/25/2022	15	0.001%	0.0001
4000466758	26639	1,215	8/11/2022	8/26/2022	15	0.000%	0.0000
4000466760	30068	650	8/11/2022	8/26/2022	15	0.000%	0.0000
4000466765	33956	744	8/11/2022	8/26/2022	15	0.000%	0.0000
4000466731	104872	1,775	8/11/2022	8/26/2022	15	0.000%	0.0001
4000466900	22798	2,970	8/17/2022	9/1/2022	15	0.001%	0.0001
4000466945	29254	4,648	8/18/2022	9/2/2022	15	0.001%	0.0002
4000467099	145193	1,600	8/23/2022	9/7/2022	15	0.000%	0.0001
4000467101	145289	10,488	8/23/2022	9/7/2022	15	0.003%	0.0004
4000467147	32875	400	8/24/2022	9/8/2022	15	0.000%	0.0000
4000467114	101853	37,955	8/24/2022	9/8/2022	15	0.010%	0.0015
4000467185	26363	2,314	8/25/2022	9/9/2022	15	0.001%	0.0001
4000467172	143314	49	8/25/2022	9/9/2022	15	0.000%	0.0000
4000467278	144487	128,151	8/29/2022	9/13/2022	15	0.034%	0.0051
4000467288	22798	17,925	8/30/2022	9/14/2022	15	0.005%	0.0007
4000467293	104872	237	8/30/2022	9/14/2022	15	0.000%	0.0000
4000467372	25029	1,352	8/31/2022	9/15/2022	15	0.000%	0.0001
4000467392	124628	15,100	8/31/2022	9/15/2022	15	0.004%	0.0006
4000467335	1101	1,500	8/31/2022	9/15/2022	15	0.000%	0.0001
4000467353	130416	2,500	8/31/2022	9/15/2022	15	0.001%	0.0001
4000467441	32896	1,900	9/1/2022	9/16/2022	15	0.001%	0.0001
4000467562	34173	3,985	9/6/2022	9/21/2022	15	0.001%	0.0002
4000467582	33924	39,155	9/7/2022	9/22/2022	15	0.010%	0.0015
4000467588	116969	8,972	9/8/2022	9/23/2022	15	0.002%	0.0004
4000467677	142942	5,091	9/12/2022	9/27/2022	15	0.001%	0.0002
4000467764	28619	16,128	9/14/2022	9/29/2022	15	0.004%	0.0006
4000467814	24114	9,625	9/15/2022	9/30/2022	15	0.003%	0.0004
4000467781	102473	12,500	9/15/2022	9/30/2022	15	0.003%	0.0005
4000467782	102473	10,550	9/15/2022	9/30/2022	15	0.003%	0.0004
4000467930	145222	736	9/20/2022	10/5/2022	15	0.000%	0.0000
4000468011	24885	700	9/22/2022	10/7/2022	15	0.000%	0.0000
4000467998	139089	545	9/22/2022	10/7/2022	15	0.000%	0.0000
4000468000	142681	72,309	9/22/2022	10/7/2022	15	0.019%	0.0029
4000468123	28619	15,400	9/26/2022	10/11/2022	15	0.004%	0.0006
4000468129	135537	31,385	9/26/2022	10/11/2022	15	0.008%	0.0012
4000468107	141302	1,500	9/26/2022	10/11/2022	15	0.000%	0.0001
4000468157	26312	9,169	9/27/2022	10/12/2022	15	0.002%	0.0004
4000468133	27476	4,619	9/27/2022	10/12/2022	15	0.001%	0.0002
4000468172	33033	85,193	9/27/2022	10/12/2022	15	0.022%	0.0034
4000468186	33117	50,267	9/27/2022	10/12/2022	15	0.013%	0.0020
4000468197	17293	19,000	9/28/2022	10/13/2022	15	0.005%	0.0008
4000468201	33624	2,910	9/28/2022	10/13/2022	15	0.001%	0.0001
4000468212	111446	10,000	9/28/2022	10/13/2022	15	0.003%	0.0004

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468292	18267	9,664	9/29/2022	10/14/2022	15	0.003%	0.0004
4000468307	105195	3,917	9/29/2022	10/14/2022	15	0.001%	0.0002
4000468267	105195	19,748	9/29/2022	10/14/2022	15	0.005%	0.0008
4000468480	18267	11,956	10/4/2022	10/19/2022	15	0.003%	0.0005
4000468483	28619	16,800	10/4/2022	10/19/2022	15	0.004%	0.0007
4000468477	142942	6,346	10/4/2022	10/19/2022	15	0.002%	0.0003
4000468491	142681	177,630	10/5/2022	10/20/2022	15	0.047%	0.0070
4000468503	26130	121,725	10/6/2022	10/21/2022	15	0.032%	0.0048
4000468663	28619	19,880	10/11/2022	10/26/2022	15	0.005%	0.0008
4000468702	134184	500	10/12/2022	10/27/2022	15	0.000%	0.0000
4000468718	145382	500	10/12/2022	10/27/2022	15	0.000%	0.0000
4000468767	11536	9,970	10/13/2022	10/28/2022	15	0.003%	0.0004
4000468770	24113	4,758	10/13/2022	10/28/2022	15	0.001%	0.0002
4000468761	144422	17,293	10/13/2022	10/28/2022	15	0.005%	0.0007
4000468887	27512	3,304	10/17/2022	11/1/2022	15	0.001%	0.0001
4000468889	32510	4,278	10/17/2022	11/1/2022	15	0.001%	0.0002
4000468855	109750	5,000	10/17/2022	11/1/2022	15	0.001%	0.0002
4000468864	139128	1,394	10/17/2022	11/1/2022	15	0.000%	0.0001
4000468867	143622	2,669	10/17/2022	11/1/2022	15	0.001%	0.0001
4000468894	103278	2,000	10/18/2022	11/2/2022	15	0.001%	0.0001
4000469160	23681	7,216	10/24/2022	11/8/2022	15	0.002%	0.0003
4000469147	142574	2,500	10/24/2022	11/8/2022	15	0.001%	0.0001
4000469148	142681	118,420	10/24/2022	11/8/2022	15	0.031%	0.0047
4000469182	142885	3,138	10/25/2022	11/9/2022	15	0.001%	0.0001
4000469208	22798	3,009	10/26/2022	11/10/2022	15	0.001%	0.0001
4000469217	119251	7,111	10/26/2022	11/10/2022	15	0.002%	0.0003
4000469220	120208	3,000	10/26/2022	11/10/2022	15	0.001%	0.0001
4000469435	13911	115,970	10/31/2022	11/15/2022	15	0.031%	0.0046
4000469438	24981	1,584	10/31/2022	11/15/2022	15	0.000%	0.0001
4000469439	25808	1,020	10/31/2022	11/15/2022	15	0.000%	0.0000
4000469441	26381	1,920	10/31/2022	11/15/2022	15	0.001%	0.0001
4000469421	139089	405	10/31/2022	11/15/2022	15	0.000%	0.0000
4000469423	142942	5,910	10/31/2022	11/15/2022	15	0.002%	0.0002
4000469428	144741	1,470	10/31/2022	11/15/2022	15	0.000%	0.0001
4000469429	144878	2,716	10/31/2022	11/15/2022	15	0.001%	0.0001
4000469460	116517	446	11/1/2022	11/16/2022	15	0.000%	0.0000
4000469464	132321	104	11/1/2022	11/16/2022	15	0.000%	0.0000
4000469455	123042	17,393	11/1/2022	11/16/2022	15	0.005%	0.0007
4000469543	34616	5,812	11/2/2022	11/17/2022	15	0.002%	0.0002
4000469546	126165	5,052	11/2/2022	11/17/2022	15	0.001%	0.0002
4000469516	144344	9,300	11/2/2022	11/17/2022	15	0.002%	0.0004
4000469487	133368	29,842	11/2/2022	11/17/2022	15	0.008%	0.0012
4000469573	145059	2,000	11/3/2022	11/18/2022	15	0.001%	0.0001
4000469684	27982	1,823	11/7/2022	11/22/2022	15	0.000%	0.0001
4000469665	108289	65	11/7/2022	11/22/2022	15	0.000%	0.0000
4000469674	143606	14,414	11/7/2022	11/22/2022	15	0.004%	0.0006
4000469677	145028	15,000	11/7/2022	11/22/2022	15	0.004%	0.0006
4000469693	142681	81,692	11/8/2022	11/23/2022	15	0.022%	0.0032
4000469818	26490	507	11/10/2022	11/25/2022	15	0.000%	0.0000
4000469776	14851	7,082	11/10/2022	11/25/2022	15	0.002%	0.0003
4000469778	18785	23,861	11/10/2022	11/25/2022	15	0.006%	0.0009
4000469797	142942	22,766	11/10/2022	11/25/2022	15	0.006%	0.0009
4000469798	143072	5,724	11/10/2022	11/25/2022	15	0.002%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469771	126796	4,152	11/10/2022	11/25/2022	15	0.001%	0.0002
4000469865	27068	8,094	11/14/2022	11/29/2022	15	0.002%	0.0003
4000469850	142942	7,527	11/14/2022	11/29/2022	15	0.002%	0.0003
4000469902	135537	36,693	11/15/2022	11/30/2022	15	0.010%	0.0015
4000469873	103131	474	11/15/2022	11/30/2022	15	0.000%	0.0000
4000469883	143072	5,772	11/15/2022	11/30/2022	15	0.002%	0.0002
4000469932	26679	13,875	11/16/2022	12/1/2022	15	0.004%	0.0005
4000469933	27389	2,473	11/16/2022	12/1/2022	15	0.001%	0.0001
4000469952	34173	20,597	11/16/2022	12/1/2022	15	0.005%	0.0008
4000469985	27068	10,602	11/17/2022	12/2/2022	15	0.003%	0.0004
4000470200	26213	6,578	11/23/2022	12/8/2022	15	0.002%	0.0003
4000470206	28530	34,596	11/23/2022	12/8/2022	15	0.009%	0.0014
4000470217	32537	4,125	11/23/2022	12/8/2022	15	0.001%	0.0002
4000470219	33203	11,443	11/23/2022	12/8/2022	15	0.003%	0.0005
4000470152	25147	120,819	11/23/2022	12/8/2022	15	0.032%	0.0048
4000470156	108289	65	11/23/2022	12/8/2022	15	0.000%	0.0000
4000470173	143072	114,552	11/23/2022	12/8/2022	15	0.030%	0.0045
4000470186	144816	13,681	11/23/2022	12/8/2022	15	0.004%	0.0005
4000470255	25029	6,136	11/28/2022	12/13/2022	15	0.002%	0.0002
4000470277	126165	3,100	11/28/2022	12/13/2022	15	0.001%	0.0001
4000470239	142942	11,059	11/28/2022	12/13/2022	15	0.003%	0.0004
4000470293	145219	7,800	11/29/2022	12/14/2022	15	0.002%	0.0003
4000470376	32897	950	11/30/2022	12/15/2022	15	0.000%	0.0000
4000470337	144422	10,820	11/30/2022	12/15/2022	15	0.003%	0.0004
4000470418	142681	151,310	12/1/2022	12/16/2022	15	0.040%	0.0060
4000470552	133230	10,000	12/5/2022	12/20/2022	15	0.003%	0.0004
4000470627	145208	1,421	12/7/2022	12/22/2022	15	0.000%	0.0001
4000470675	26381	10,000	12/8/2022	12/23/2022	15	0.003%	0.0004
4000470770	26363	1,227	12/12/2022	12/27/2022	15	0.000%	0.0000
4000470774	27389	1,783	12/12/2022	12/27/2022	15	0.000%	0.0001
4000470745	104872	213	12/12/2022	12/27/2022	15	0.000%	0.0000
4000470807	130375	7,111	12/13/2022	12/28/2022	15	0.002%	0.0003
4000470794	145222	6,302	12/13/2022	12/28/2022	15	0.002%	0.0002
4000470782	102060	39,668	12/13/2022	12/28/2022	15	0.010%	0.0016
4000470848	25659	17,665	12/14/2022	12/29/2022	15	0.005%	0.0007
4000470811	9891	1,001	12/14/2022	12/29/2022	15	0.000%	0.0000
4000470899	145259	30,561	12/15/2022	12/30/2022	15	0.008%	0.0012
4000471041	8392	15,735	12/19/2022	1/3/2023	15	0.004%	0.0006
4000471028	22902	1,938	12/19/2022	1/3/2023	15	0.001%	0.0001
4000471069	141583	138	12/20/2022	1/4/2023	15	0.000%	0.0000
4000471154	26363	2,780	12/21/2022	1/5/2023	15	0.001%	0.0001
4000471156	26588	15,245	12/21/2022	1/5/2023	15	0.004%	0.0006
4000471158	26642	2,538	12/21/2022	1/5/2023	15	0.001%	0.0001
4000471167	30475	810	12/21/2022	1/5/2023	15	0.000%	0.0000
4000471117	107313	5,000	12/21/2022	1/5/2023	15	0.001%	0.0002
4000471132	144773	625	12/21/2022	1/5/2023	15	0.000%	0.0000
4000471205	26297	387	12/22/2022	1/6/2023	15	0.000%	0.0000
4000471178	101853	13,827	12/22/2022	1/6/2023	15	0.004%	0.0005
4000471183	118807	61	12/22/2022	1/6/2023	15	0.000%	0.0000
4000471184	119251	7,573	12/22/2022	1/6/2023	15	0.002%	0.0003
4000471185	123377	2,763	12/22/2022	1/6/2023	15	0.001%	0.0001
4000471194	143577	7,419	12/22/2022	1/6/2023	15	0.002%	0.0003
4000471389	26299	7,072	12/29/2022	1/13/2023	15	0.002%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471390	26312	25,320	12/29/2022	1/13/2023	15	0.007%	0.0010
4000471393	26363	955	12/29/2022	1/13/2023	15	0.000%	0.0000
4000471394	26381	63,040	12/29/2022	1/13/2023	15	0.017%	0.0025
4000471395	26382	1,803	12/29/2022	1/13/2023	15	0.000%	0.0001
4000471415	135537	41,045	12/29/2022	1/13/2023	15	0.011%	0.0016
4000459733	26655	785	1/10/2022	1/26/2022	16	0.000%	0.0000
4000459735	26674	3,150	1/10/2022	1/26/2022	16	0.001%	0.0001
4000459703	104872	1,084	1/10/2022	1/26/2022	16	0.000%	0.0000
4000459741	10439	2,310	1/11/2022	1/27/2022	16	0.001%	0.0001
4000459789	24251	2,520	1/12/2022	1/28/2022	16	0.001%	0.0001
4000460014	118029	5,600	1/19/2022	2/4/2022	16	0.001%	0.0002
4000460157	26323	5,698	1/24/2022	2/9/2022	16	0.002%	0.0002
4000460140	139089	17	1/24/2022	2/9/2022	16	0.000%	0.0000
4000460228	25926	14,955	1/25/2022	2/10/2022	16	0.004%	0.0006
4000460307	135537	8,820	1/26/2022	2/11/2022	16	0.002%	0.0004
4000460608	26643	3,367	1/31/2022	2/16/2022	16	0.001%	0.0001
4000460576	142642	1	1/31/2022	2/16/2022	16	0.000%	0.0000
4000460650	142874	12,312	2/1/2022	2/17/2022	16	0.003%	0.0005
4000460654	143270	4,500	2/1/2022	2/17/2022	16	0.001%	0.0002
4000460617	103278	125	2/1/2022	2/17/2022	16	0.000%	0.0000
4000460689	132321	104	2/2/2022	2/18/2022	16	0.000%	0.0000
4000460851	130375	8,739	2/7/2022	2/23/2022	16	0.002%	0.0004
4000460862	124754	1,545	2/8/2022	2/24/2022	16	0.000%	0.0001
4000461078	130231	9,500	2/15/2022	3/3/2022	16	0.003%	0.0004
4000461159	130375	2,981	2/16/2022	3/4/2022	16	0.001%	0.0001
4000461298	25029	1,352	2/22/2022	3/10/2022	16	0.000%	0.0001
4000461508	27704	800	2/28/2022	3/16/2022	16	0.000%	0.0000
4000461482	123383	12,420	2/28/2022	3/16/2022	16	0.003%	0.0005
4000461595	25908	15,188	3/2/2022	3/18/2022	16	0.004%	0.0006
4000461571	142942	8,904	3/2/2022	3/18/2022	16	0.002%	0.0004
4000461588	144953	4,139	3/2/2022	3/18/2022	16	0.001%	0.0002
4000461727	25808	960	3/8/2022	3/24/2022	16	0.000%	0.0000
4000461870	32944	26,274	3/14/2022	3/30/2022	16	0.007%	0.0011
4000461871	33024	72,554	3/14/2022	3/30/2022	16	0.019%	0.0031
4000461878	24211	1,010	3/15/2022	3/31/2022	16	0.000%	0.0000
4000462098	26299	1,767	3/21/2022	4/6/2022	16	0.000%	0.0001
4000462166	106699	4,231	3/23/2022	4/8/2022	16	0.001%	0.0002
4000462279	130375	7,360	3/28/2022	4/13/2022	16	0.002%	0.0003
4000462242	11427	2,500	3/28/2022	4/13/2022	16	0.001%	0.0001
4000462251	126570	646	3/28/2022	4/13/2022	16	0.000%	0.0000
4000462298	9673	11,575	3/29/2022	4/14/2022	16	0.003%	0.0005
4000462309	26493	5,096	3/29/2022	4/14/2022	16	0.001%	0.0002
4000462379	9891	2,703	3/30/2022	4/15/2022	16	0.001%	0.0001
4000462338	116559	250	3/30/2022	4/15/2022	16	0.000%	0.0000
4000462339	116902	1,800	3/30/2022	4/15/2022	16	0.000%	0.0001
4000462346	129039	2,500	3/30/2022	4/15/2022	16	0.001%	0.0001
4000462360	142688	60,000	3/30/2022	4/15/2022	16	0.016%	0.0025
4000462580	144344	5,000	4/4/2022	4/20/2022	16	0.001%	0.0002
4000462595	117183	2,200	4/5/2022	4/21/2022	16	0.001%	0.0001
4000462752	124628	3,619	4/11/2022	4/27/2022	16	0.001%	0.0002
4000462936	22798	304	4/18/2022	5/4/2022	16	0.000%	0.0000
4000463028	135537	14,209	4/20/2022	5/6/2022	16	0.004%	0.0006
4000463148	101246	300	4/25/2022	5/11/2022	16	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000463152	118757	7,500	4/25/2022	5/11/2022	16	0.002%	0.0003
4000463155	139230	1,000	4/25/2022	5/11/2022	16	0.000%	0.0000
4000463194	25029	3,692	4/26/2022	5/12/2022	16	0.001%	0.0002
4000463226	143478	2,500	4/27/2022	5/13/2022	16	0.001%	0.0001
4000463438	28619	12,331	5/2/2022	5/18/2022	16	0.003%	0.0005
4000463440	106699	39,371	5/2/2022	5/18/2022	16	0.010%	0.0017
4000463530	144724	395,769	5/4/2022	5/20/2022	16	0.104%	0.0167
4000463665	11536	800	5/10/2022	5/26/2022	16	0.000%	0.0000
4000463666	13911	2,200	5/10/2022	5/26/2022	16	0.001%	0.0001
4000463685	126165	1,033	5/10/2022	5/26/2022	16	0.000%	0.0000
4000463648	27230	57,192	5/10/2022	5/26/2022	16	0.015%	0.0024
4000463728	106699	4,706	5/11/2022	5/27/2022	16	0.001%	0.0002
4000463824	11427	19,000	5/16/2022	6/1/2022	16	0.005%	0.0008
4000463838	116902	20,622	5/16/2022	6/1/2022	16	0.005%	0.0009
4000463851	125829	575	5/16/2022	6/1/2022	16	0.000%	0.0000
4000463861	133915	500	5/16/2022	6/1/2022	16	0.000%	0.0000
4000463924	130375	41,955	5/17/2022	6/2/2022	16	0.011%	0.0018
4000464077	124248	1,300	5/23/2022	6/8/2022	16	0.000%	0.0001
4000464103	129757	49	5/24/2022	6/9/2022	16	0.000%	0.0000
4000464138	26996	5,285	5/25/2022	6/10/2022	16	0.001%	0.0002
4000464352	26299	7,381	5/31/2022	6/16/2022	16	0.002%	0.0003
4000464565	26639	7,088	6/6/2022	6/22/2022	16	0.002%	0.0003
4000464548	126634	1,713	6/6/2022	6/22/2022	16	0.000%	0.0001
4000464589	144855	14,750	6/7/2022	6/23/2022	16	0.004%	0.0006
4000464847	26301	899	6/15/2022	7/1/2022	16	0.000%	0.0000
4000464979	14294	500	6/20/2022	7/6/2022	16	0.000%	0.0000
4000464987	135265	500	6/20/2022	7/6/2022	16	0.000%	0.0000
4000464988	141335	1,000	6/20/2022	7/6/2022	16	0.000%	0.0000
4000465038	25808	1,920	6/22/2022	7/8/2022	16	0.001%	0.0001
4000465218	25908	19,188	6/27/2022	7/13/2022	16	0.005%	0.0008
4000465220	26490	760	6/27/2022	7/13/2022	16	0.000%	0.0000
4000465187	124628	19,918	6/27/2022	7/13/2022	16	0.005%	0.0008
4000465258	14463	69,230	6/28/2022	7/14/2022	16	0.018%	0.0029
4000465260	24885	2,700	6/28/2022	7/14/2022	16	0.001%	0.0001
4000465484	20063	20,812	7/5/2022	7/21/2022	16	0.005%	0.0009
4000465640	142942	6,664	7/11/2022	7/27/2022	16	0.002%	0.0003
4000465768	34173	3,933	7/13/2022	7/29/2022	16	0.001%	0.0002
4000465905	11372	862	7/19/2022	8/4/2022	16	0.000%	0.0000
4000466379	26363	1,054	8/1/2022	8/17/2022	16	0.000%	0.0000
4000466346	104872	182	8/1/2022	8/17/2022	16	0.000%	0.0000
4000466355	142942	6,738	8/1/2022	8/17/2022	16	0.002%	0.0003
4000466425	103471	380	8/2/2022	8/18/2022	16	0.000%	0.0000
4000466452	123383	18,760	8/3/2022	8/19/2022	16	0.005%	0.0008
4000466482	32986	48,943	8/3/2022	8/19/2022	16	0.013%	0.0021
4000466600	25905	19,250	8/8/2022	8/24/2022	16	0.005%	0.0008
4000466611	34173	3,859	8/8/2022	8/24/2022	16	0.001%	0.0002
4000466614	113747	3,000	8/9/2022	8/25/2022	16	0.001%	0.0001
4000466680	26493	5,320	8/10/2022	8/26/2022	16	0.001%	0.0002
4000466692	34616	3,518	8/10/2022	8/26/2022	16	0.001%	0.0001
4000466840	25659	31,888	8/15/2022	8/31/2022	16	0.008%	0.0013
4000466831	141583	482	8/15/2022	8/31/2022	16	0.000%	0.0000
4000466858	126356	2,629	8/16/2022	9/1/2022	16	0.001%	0.0001
4000466929	26642	5,395	8/17/2022	9/2/2022	16	0.001%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467076	142311	432	8/22/2022	9/7/2022	16	0.000%	0.0000
4000467088	120687	160	8/23/2022	9/8/2022	16	0.000%	0.0000
4000467281	11631	13,000	8/29/2022	9/14/2022	16	0.003%	0.0005
4000467314	145198	14,783	8/30/2022	9/15/2022	16	0.004%	0.0006
4000467355	132470	550	8/31/2022	9/16/2022	16	0.000%	0.0000
4000467931	8392	66,899	9/20/2022	10/6/2022	16	0.018%	0.0028
4000468122	27162	32,060	9/26/2022	10/12/2022	16	0.008%	0.0014
4000468240	8392	17,265	9/28/2022	10/14/2022	16	0.005%	0.0007
4000468241	8998	5,995	9/28/2022	10/14/2022	16	0.002%	0.0003
4000468243	9891	3,907	9/28/2022	10/14/2022	16	0.001%	0.0002
4000468238	145390	3,000	9/28/2022	10/14/2022	16	0.001%	0.0001
4000468192	102060	142,200	9/28/2022	10/14/2022	16	0.038%	0.0060
4000468448	18267	2,048	10/3/2022	10/19/2022	16	0.001%	0.0001
4000468465	27994	32,010	10/3/2022	10/19/2022	16	0.008%	0.0014
4000468429	105195	4,324	10/3/2022	10/19/2022	16	0.001%	0.0002
4000468433	142942	5,632	10/3/2022	10/19/2022	16	0.001%	0.0002
4000468442	145222	13,904	10/3/2022	10/19/2022	16	0.004%	0.0006
4000468737	34616	17,833	10/12/2022	10/28/2022	16	0.005%	0.0008
4000468699	126283	1,000	10/12/2022	10/28/2022	16	0.000%	0.0000
4000468873	11304	3,300	10/17/2022	11/2/2022	16	0.001%	0.0001
4000468958	27068	21,546	10/19/2022	11/4/2022	16	0.006%	0.0009
4000469155	144764	600	10/24/2022	11/9/2022	16	0.000%	0.0000
4000469168	26130	84,000	10/25/2022	11/10/2022	16	0.022%	0.0035
4000469175	123377	10,143	10/25/2022	11/10/2022	16	0.003%	0.0004
4000469431	8392	32,266	10/31/2022	11/16/2022	16	0.009%	0.0014
4000469440	26299	453	10/31/2022	11/16/2022	16	0.000%	0.0000
4000469408	100212	10,000	10/31/2022	11/16/2022	16	0.003%	0.0004
4000469500	134906	3,900	11/2/2022	11/18/2022	16	0.001%	0.0002
4000469507	142002	7,696	11/2/2022	11/18/2022	16	0.002%	0.0003
4000469511	142874	12,939	11/2/2022	11/18/2022	16	0.003%	0.0005
4000469717	108294	1,000	11/9/2022	11/25/2022	16	0.000%	0.0000
4000469724	131129	2,500	11/9/2022	11/25/2022	16	0.001%	0.0001
4000469866	34616	831	11/14/2022	11/30/2022	16	0.000%	0.0000
4000469839	103378	7,500	11/14/2022	11/30/2022	16	0.002%	0.0003
4000469843	113362	4,404	11/14/2022	11/30/2022	16	0.001%	0.0002
4000469845	124628	9,325	11/14/2022	11/30/2022	16	0.002%	0.0004
4000469891	11372	2,106	11/15/2022	12/1/2022	16	0.001%	0.0001
4000469893	24259	1,413	11/15/2022	12/1/2022	16	0.000%	0.0001
4000469895	25029	7,176	11/15/2022	12/1/2022	16	0.002%	0.0003
4000469898	28619	3,808	11/15/2022	12/1/2022	16	0.001%	0.0002
4000469886	144581	5,074	11/15/2022	12/1/2022	16	0.001%	0.0002
4000469889	145056	56,172	11/15/2022	12/1/2022	16	0.015%	0.0024
4000469903	24856	545	11/16/2022	12/2/2022	16	0.000%	0.0000
4000469905	102473	2,900	11/16/2022	12/2/2022	16	0.001%	0.0001
4000470086	8392	4,408	11/21/2022	12/7/2022	16	0.001%	0.0002
4000470088	11536	600	11/21/2022	12/7/2022	16	0.000%	0.0000
4000470077	143994	50,096	11/21/2022	12/7/2022	16	0.013%	0.0021
4000470145	32897	3,700	11/22/2022	12/8/2022	16	0.001%	0.0002
4000470207	28619	1,904	11/23/2022	12/9/2022	16	0.001%	0.0001
4000470218	32875	4,800	11/23/2022	12/9/2022	16	0.001%	0.0002
4000470160	116384	243	11/23/2022	12/9/2022	16	0.000%	0.0000
4000470176	143436	836	11/23/2022	12/9/2022	16	0.000%	0.0000
4000470193	145293	7,346	11/23/2022	12/9/2022	16	0.002%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470261	26363	2,345	11/28/2022	12/14/2022	16	0.001%	0.0001
4000470274	34173	1,190	11/28/2022	12/14/2022	16	0.000%	0.0001
4000470305	26382	1,420	11/29/2022	12/15/2022	16	0.000%	0.0001
4000470327	125742	1,070	11/30/2022	12/16/2022	16	0.000%	0.0000
4000470599	6031	77	12/7/2022	12/23/2022	16	0.000%	0.0000
4000470781	130375	37,614	12/12/2022	12/28/2022	16	0.010%	0.0016
4000470851	26213	1,886	12/14/2022	12/30/2022	16	0.000%	0.0001
4000471027	6396	600	12/19/2022	1/4/2023	16	0.000%	0.0000
4000471039	144567	24,515	12/19/2022	1/4/2023	16	0.006%	0.0010
4000471040	144813	20,475	12/19/2022	1/4/2023	16	0.005%	0.0009
4000471090	25987	1,650	12/20/2022	1/5/2023	16	0.000%	0.0001
4000471095	27389	5,520	12/20/2022	1/5/2023	16	0.001%	0.0002
4000471063	118807	54	12/20/2022	1/5/2023	16	0.000%	0.0000
4000471137	8392	17,939	12/21/2022	1/6/2023	16	0.005%	0.0008
4000471138	9673	9,325	12/21/2022	1/6/2023	16	0.002%	0.0004
4000471113	33624	129,040	12/21/2022	1/6/2023	16	0.034%	0.0054
4000471114	36403	18	12/21/2022	1/6/2023	16	0.000%	0.0000
4000471135	145394	10,000	12/21/2022	1/6/2023	16	0.003%	0.0004
4000471290	26207	2,600	12/27/2022	1/12/2023	16	0.001%	0.0001
4000471295	26643	1,398	12/27/2022	1/12/2023	16	0.000%	0.0001
4000471322	26381	640	12/28/2022	1/13/2023	16	0.000%	0.0000
4000471325	27068	15,105	12/28/2022	1/13/2023	16	0.004%	0.0006
4000459676	13911	898	1/7/2022	1/24/2022	17	0.000%	0.0000
4000459683	25599	1,256	1/7/2022	1/24/2022	17	0.000%	0.0001
4000459692	27636	4,000	1/7/2022	1/24/2022	17	0.001%	0.0002
4000459719	24259	1,265	1/10/2022	1/27/2022	17	0.000%	0.0001
4000459729	26363	18,486	1/10/2022	1/27/2022	17	0.005%	0.0008
4000459705	132321	104	1/10/2022	1/27/2022	17	0.000%	0.0000
4000459758	24251	3,540	1/11/2022	1/28/2022	17	0.001%	0.0002
4000459936	32970	144,262	1/14/2022	1/31/2022	17	0.038%	0.0065
4000459938	32978	2,693	1/14/2022	1/31/2022	17	0.001%	0.0001
4000459992	24251	720	1/18/2022	2/4/2022	17	0.000%	0.0000
4000459962	100893	905	1/18/2022	2/4/2022	17	0.000%	0.0000
4000460124	126165	2,755	1/21/2022	2/7/2022	17	0.001%	0.0001
4000460106	103047	46	1/21/2022	2/7/2022	17	0.000%	0.0000
4000460156	26301	6,367	1/24/2022	2/10/2022	17	0.002%	0.0003
4000460136	119251	6,854	1/24/2022	2/10/2022	17	0.002%	0.0003
4000460142	139275	195	1/24/2022	2/10/2022	17	0.000%	0.0000
4000460130	139796	3,000	1/24/2022	2/10/2022	17	0.001%	0.0001
4000460984	6031	2,908	2/11/2022	2/28/2022	17	0.001%	0.0001
4000460993	101853	2,493	2/11/2022	2/28/2022	17	0.001%	0.0001
4000461010	125783	390	2/11/2022	2/28/2022	17	0.000%	0.0000
4000461022	142926	62,642	2/11/2022	2/28/2022	17	0.017%	0.0028
4000461229	126928	318	2/18/2022	3/7/2022	17	0.000%	0.0000
4000461208	142370	4,600	2/18/2022	3/7/2022	17	0.001%	0.0002
4000461279	129957	5,000	2/22/2022	3/11/2022	17	0.001%	0.0002
4000461288	142942	6,749	2/22/2022	3/11/2022	17	0.002%	0.0003
4000461445	24251	6,180	2/25/2022	3/14/2022	17	0.002%	0.0003
4000461427	139089	374	2/25/2022	3/14/2022	17	0.000%	0.0000
4000461517	130375	4,153	2/28/2022	3/17/2022	17	0.001%	0.0002
4000461525	142942	7,494	3/1/2022	3/18/2022	17	0.002%	0.0003
4000461664	28619	12,701	3/4/2022	3/21/2022	17	0.003%	0.0006
4000461637	106674	15,769	3/4/2022	3/21/2022	17	0.004%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461701	144951	1,000	3/7/2022	3/24/2022	17	0.000%	0.0000
4000461828	137757	38,841	3/11/2022	3/28/2022	17	0.010%	0.0017
4000461836	144921	4,444	3/11/2022	3/28/2022	17	0.001%	0.0002
4000461867	24211	7,727	3/14/2022	3/31/2022	17	0.002%	0.0003
4000461856	114121	50,739	3/14/2022	3/31/2022	17	0.013%	0.0023
4000461911	26362	800	3/15/2022	4/1/2022	17	0.000%	0.0000
4000461915	28619	12,091	3/15/2022	4/1/2022	17	0.003%	0.0005
4000461875	107151	5,332	3/15/2022	4/1/2022	17	0.001%	0.0002
4000462041	25173	880	3/18/2022	4/4/2022	17	0.000%	0.0000
4000462007	6031	2,616	3/18/2022	4/4/2022	17	0.001%	0.0001
4000462022	139089	18	3/18/2022	4/4/2022	17	0.000%	0.0000
4000462273	28619	1,672	3/28/2022	4/14/2022	17	0.000%	0.0001
4000462522	18267	19,581	4/1/2022	4/18/2022	17	0.005%	0.0009
4000462523	23681	1,591	4/1/2022	4/18/2022	17	0.000%	0.0001
4000462546	105195	15,267	4/1/2022	4/18/2022	17	0.004%	0.0007
4000462484	105195	8,932	4/1/2022	4/18/2022	17	0.002%	0.0004
4000462594	107151	7,374	4/5/2022	4/22/2022	17	0.002%	0.0003
4000462729	26643	7,809	4/8/2022	4/25/2022	17	0.002%	0.0004
4000462738	33770	28,735	4/8/2022	4/25/2022	17	0.008%	0.0013
4000462709	142942	19,561	4/8/2022	4/25/2022	17	0.005%	0.0009
4000462780	33033	86,663	4/11/2022	4/28/2022	17	0.023%	0.0039
4000462964	130375	817	4/18/2022	5/5/2022	17	0.000%	0.0000
4000463132	32875	600	4/22/2022	5/9/2022	17	0.000%	0.0000
4000463078	6031	3,583	4/22/2022	5/9/2022	17	0.001%	0.0002
4000463079	10155	2,970	4/22/2022	5/9/2022	17	0.001%	0.0001
4000463081	24114	715	4/22/2022	5/9/2022	17	0.000%	0.0000
4000463153	133702	150	4/25/2022	5/12/2022	17	0.000%	0.0000
4000463156	139350	17,500	4/25/2022	5/12/2022	17	0.005%	0.0008
4000463162	143497	750	4/25/2022	5/12/2022	17	0.000%	0.0000
4000463373	24211	10,746	4/29/2022	5/16/2022	17	0.003%	0.0005
4000463335	112215	1,290	4/29/2022	5/16/2022	17	0.000%	0.0001
4000463340	134862	27,667	4/29/2022	5/16/2022	17	0.007%	0.0012
4000463353	143520	2,194	4/29/2022	5/16/2022	17	0.001%	0.0001
4000463358	143991	12,588	4/29/2022	5/16/2022	17	0.003%	0.0006
4000463455	32138	38,940	5/3/2022	5/20/2022	17	0.010%	0.0017
4000463503	145091	15,000	5/3/2022	5/20/2022	17	0.004%	0.0007
4000463620	32853	1,080	5/6/2022	5/23/2022	17	0.000%	0.0000
4000463626	135537	2,340	5/6/2022	5/23/2022	17	0.001%	0.0001
4000463602	144422	29,228	5/6/2022	5/23/2022	17	0.008%	0.0013
4000463603	144540	3,360	5/6/2022	5/23/2022	17	0.001%	0.0002
4000463893	26363	1,756	5/16/2022	6/2/2022	17	0.000%	0.0001
4000463905	130375	5,556	5/16/2022	6/2/2022	17	0.001%	0.0002
4000463839	117108	54	5/16/2022	6/2/2022	17	0.000%	0.0000
4000463877	145133	54	5/16/2022	6/2/2022	17	0.000%	0.0000
4000464290	8392	10,570	5/27/2022	6/13/2022	17	0.003%	0.0005
4000464293	13911	1,370	5/27/2022	6/13/2022	17	0.000%	0.0001
4000464309	126165	3,157	5/27/2022	6/13/2022	17	0.001%	0.0001
4000464254	104872	6	5/27/2022	6/13/2022	17	0.000%	0.0000
4000464282	143991	9,673	5/27/2022	6/13/2022	17	0.003%	0.0004
4000464576	107809	50	6/7/2022	6/24/2022	17	0.000%	0.0000
4000464683	6031	2,248	6/10/2022	6/27/2022	17	0.001%	0.0001
4000464700	126796	6,025	6/10/2022	6/27/2022	17	0.002%	0.0003
4000464706	142942	17,800	6/10/2022	6/27/2022	17	0.005%	0.0008

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464768	25908	8,750	6/13/2022	6/30/2022	17	0.002%	0.0004
4000464774	26362	800	6/13/2022	6/30/2022	17	0.000%	0.0000
4000464789	102473	650	6/14/2022	7/1/2022	17	0.000%	0.0000
4000465010	8392	21,703	6/21/2022	7/8/2022	17	0.006%	0.0010
4000465144	9891	40,827	6/24/2022	7/11/2022	17	0.011%	0.0018
4000465149	14463	15,600	6/24/2022	7/11/2022	17	0.004%	0.0007
4000465158	26639	4,050	6/24/2022	7/11/2022	17	0.001%	0.0002
4000465112	6031	2,535	6/24/2022	7/11/2022	17	0.001%	0.0001
4000465109	120010	2,665	6/24/2022	7/11/2022	17	0.001%	0.0001
4000465214	25029	7,956	6/27/2022	7/14/2022	17	0.002%	0.0004
4000465179	103230	50,000	6/27/2022	7/14/2022	17	0.013%	0.0022
4000465432	24211	1,414	7/1/2022	7/18/2022	17	0.000%	0.0001
4000465458	32245	3,334	7/1/2022	7/18/2022	17	0.001%	0.0001
4000465467	124628	3,559	7/1/2022	7/18/2022	17	0.001%	0.0002
4000465726	11427	14,200	7/12/2022	7/29/2022	17	0.004%	0.0006
4000465823	137757	1,351	7/15/2022	8/1/2022	17	0.000%	0.0001
4000465904	145236	17,250	7/19/2022	8/5/2022	17	0.005%	0.0008
4000466053	9891	28,029	7/22/2022	8/8/2022	17	0.007%	0.0013
4000466057	13911	1,100	7/22/2022	8/8/2022	17	0.000%	0.0000
4000466069	26643	778	7/22/2022	8/8/2022	17	0.000%	0.0000
4000466033	126643	100	7/22/2022	8/8/2022	17	0.000%	0.0000
4000466096	11304	600	7/25/2022	8/11/2022	17	0.000%	0.0000
4000466163	104725	950	7/26/2022	8/12/2022	17	0.000%	0.0000
4000466306	26604	16,670	7/29/2022	8/15/2022	17	0.004%	0.0007
4000466311	27389	1,610	7/29/2022	8/15/2022	17	0.000%	0.0001
4000466314	27962	4,445	7/29/2022	8/15/2022	17	0.001%	0.0002
4000466255	6031	155	7/29/2022	8/15/2022	17	0.000%	0.0000
4000466268	101853	744	7/29/2022	8/15/2022	17	0.000%	0.0000
4000466282	143520	2,259	7/29/2022	8/15/2022	17	0.001%	0.0001
4000466351	139089	437	8/1/2022	8/18/2022	17	0.000%	0.0000
4000466571	28619	8,569	8/5/2022	8/22/2022	17	0.002%	0.0004
4000466574	32897	1,400	8/5/2022	8/22/2022	17	0.000%	0.0001
4000466575	33956	4,994	8/5/2022	8/22/2022	17	0.001%	0.0002
4000466553	143473	1,700	8/5/2022	8/22/2022	17	0.000%	0.0001
4000466560	144530	152	8/5/2022	8/22/2022	17	0.000%	0.0000
4000466562	145222	4,738	8/5/2022	8/22/2022	17	0.001%	0.0002
4000466769	6031	1,899	8/12/2022	8/29/2022	17	0.001%	0.0001
4000466839	24211	6,868	8/15/2022	9/1/2022	17	0.002%	0.0003
4000466843	26490	12,140	8/15/2022	9/1/2022	17	0.003%	0.0005
4000467081	9673	2,100	8/22/2022	9/8/2022	17	0.001%	0.0001
4000467062	101853	22,271	8/22/2022	9/8/2022	17	0.006%	0.0010
4000467071	124628	8,362	8/22/2022	9/8/2022	17	0.002%	0.0004
4000467100	145288	1,196	8/23/2022	9/9/2022	17	0.000%	0.0001
4000467231	8392	45,205	8/26/2022	9/12/2022	17	0.012%	0.0020
4000467234	24292	1,390	8/26/2022	9/12/2022	17	0.000%	0.0001
4000467239	27962	1,767	8/26/2022	9/12/2022	17	0.000%	0.0001
4000467241	27994	2,585	8/26/2022	9/12/2022	17	0.001%	0.0001
4000467243	30068	1,875	8/26/2022	9/12/2022	17	0.000%	0.0001
4000467198	6031	110	8/26/2022	9/12/2022	17	0.000%	0.0000
4000467205	101853	23,451	8/26/2022	9/12/2022	17	0.006%	0.0011
4000467229	145222	4,002	8/26/2022	9/12/2022	17	0.001%	0.0002
4000467524	27389	1,840	9/2/2022	9/19/2022	17	0.000%	0.0001
4000467538	126165	3,387	9/2/2022	9/19/2022	17	0.001%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467450	6031	97	9/2/2022	9/19/2022	17	0.000%	0.0000
4000467468	131647	3,086	9/2/2022	9/19/2022	17	0.001%	0.0001
4000467477	141583	378	9/2/2022	9/19/2022	17	0.000%	0.0000
4000467497	144015	10,000	9/2/2022	9/19/2022	17	0.003%	0.0004
4000467501	144510	2,000	9/2/2022	9/19/2022	17	0.001%	0.0001
4000467560	26644	3,240	9/6/2022	9/23/2022	17	0.001%	0.0001
4000467540	107151	5,618	9/6/2022	9/23/2022	17	0.001%	0.0003
4000467664	34348	3,240	9/9/2022	9/26/2022	17	0.001%	0.0001
4000467623	6031	1,319	9/9/2022	9/26/2022	17	0.000%	0.0001
4000467863	9673	3,900	9/16/2022	10/3/2022	17	0.001%	0.0002
4000467865	13911	440	9/16/2022	10/3/2022	17	0.000%	0.0000
4000467867	24825	5,387	9/16/2022	10/3/2022	17	0.001%	0.0002
4000467868	26301	9,587	9/16/2022	10/3/2022	17	0.003%	0.0004
4000467869	26604	27,405	9/16/2022	10/3/2022	17	0.007%	0.0012
4000467886	135537	24,023	9/16/2022	10/3/2022	17	0.006%	0.0011
4000467837	11427	22,000	9/16/2022	10/3/2022	17	0.006%	0.0010
4000467862	145193	3,645	9/16/2022	10/3/2022	17	0.001%	0.0002
4000468106	135448	5,000	9/26/2022	10/13/2022	17	0.001%	0.0002
4000468410	28084	29,260	9/30/2022	10/17/2022	17	0.008%	0.0013
4000468411	28737	1,841	9/30/2022	10/17/2022	17	0.000%	0.0001
4000468412	32245	1,108	9/30/2022	10/17/2022	17	0.000%	0.0000
4000468312	8774	611	9/30/2022	10/17/2022	17	0.000%	0.0000
4000468327	107047	23,452	9/30/2022	10/17/2022	17	0.006%	0.0011
4000468330	112103	59,375	9/30/2022	10/17/2022	17	0.016%	0.0027
4000468345	137912	4,052	9/30/2022	10/17/2022	17	0.001%	0.0002
4000468355	142164	5,356	9/30/2022	10/17/2022	17	0.001%	0.0002
4000468379	144546	4,900	9/30/2022	10/17/2022	17	0.001%	0.0002
4000468454	26299	4,538	10/3/2022	10/20/2022	17	0.001%	0.0002
4000468475	139275	268	10/4/2022	10/21/2022	17	0.000%	0.0000
4000468595	30068	130	10/7/2022	10/24/2022	17	0.000%	0.0000
4000468549	103603	5,245	10/7/2022	10/24/2022	17	0.001%	0.0002
4000468650	25599	10,159	10/11/2022	10/28/2022	17	0.003%	0.0005
4000468669	34616	13,680	10/11/2022	10/28/2022	17	0.004%	0.0006
4000468624	116138	16,100	10/11/2022	10/28/2022	17	0.004%	0.0007
4000468821	13911	3,590	10/14/2022	10/31/2022	17	0.001%	0.0002
4000468828	27389	1,208	10/14/2022	10/31/2022	17	0.000%	0.0001
4000468837	33956	4,269	10/14/2022	10/31/2022	17	0.001%	0.0002
4000468786	6031	1,585	10/14/2022	10/31/2022	17	0.000%	0.0001
4000468805	142942	19,419	10/14/2022	10/31/2022	17	0.005%	0.0009
4000468806	142942	500	10/14/2022	10/31/2022	17	0.000%	0.0000
4000468900	102473	9,360	10/18/2022	11/4/2022	17	0.002%	0.0004
4000469088	124628	77,675	10/21/2022	11/7/2022	17	0.020%	0.0035
4000469165	125016	2,958	10/24/2022	11/10/2022	17	0.001%	0.0001
4000469156	145222	5,382	10/24/2022	11/10/2022	17	0.001%	0.0002
4000469364	9673	17,400	10/28/2022	11/14/2022	17	0.005%	0.0008
4000469329	15871	7,945	10/28/2022	11/14/2022	17	0.002%	0.0004
4000469338	111664	30,000	10/28/2022	11/14/2022	17	0.008%	0.0013
4000469649	30475	47,093	11/4/2022	11/21/2022	17	0.012%	0.0021
4000469650	30475	50,114	11/4/2022	11/21/2022	17	0.013%	0.0022
4000469651	30475	53,671	11/4/2022	11/21/2022	17	0.014%	0.0024
4000469652	30475	59,342	11/4/2022	11/21/2022	17	0.016%	0.0027
4000469653	30475	64,720	11/4/2022	11/21/2022	17	0.017%	0.0029
4000469654	30475	73,790	11/4/2022	11/21/2022	17	0.019%	0.0033

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469619	126928	94	11/4/2022	11/21/2022	17	0.000%	0.0000
4000469629	144567	71,575	11/4/2022	11/21/2022	17	0.019%	0.0032
4000469857	11304	10,500	11/14/2022	12/1/2022	17	0.003%	0.0005
4000469858	11427	14,250	11/14/2022	12/1/2022	17	0.004%	0.0006
4000469864	26643	1,731	11/14/2022	12/1/2022	17	0.000%	0.0001
4000470025	8392	30,827	11/18/2022	12/5/2022	17	0.008%	0.0014
4000469997	26256	2,625	11/18/2022	12/5/2022	17	0.001%	0.0001
4000470015	143072	61,448	11/18/2022	12/5/2022	17	0.016%	0.0028
4000470022	145222	966	11/18/2022	12/5/2022	17	0.000%	0.0000
4000470098	28619	14,960	11/21/2022	12/8/2022	17	0.004%	0.0007
4000470055	103392	263	11/21/2022	12/8/2022	17	0.000%	0.0000
4000470144	28619	3,696	11/22/2022	12/9/2022	17	0.001%	0.0002
4000470112	126928	136	11/22/2022	12/9/2022	17	0.000%	0.0000
4000470113	126928	80	11/22/2022	12/9/2022	17	0.000%	0.0000
4000470250	14463	34,674	11/28/2022	12/15/2022	17	0.009%	0.0016
4000470273	32897	850	11/28/2022	12/15/2022	17	0.000%	0.0000
4000470287	143189	6,547	11/29/2022	12/16/2022	17	0.002%	0.0003
4000470522	10630	880	12/2/2022	12/19/2022	17	0.000%	0.0000
4000470527	26381	4,160	12/2/2022	12/19/2022	17	0.001%	0.0002
4000470537	126165	918	12/2/2022	12/19/2022	17	0.000%	0.0000
4000470538	135537	59,700	12/2/2022	12/19/2022	17	0.016%	0.0027
4000470471	141025	18,000	12/2/2022	12/19/2022	17	0.005%	0.0008
4000470480	142681	151,310	12/2/2022	12/19/2022	17	0.040%	0.0068
4000470510	144996	2,500	12/2/2022	12/19/2022	17	0.001%	0.0001
4000470518	145251	8,008	12/2/2022	12/19/2022	17	0.002%	0.0004
4000470554	134480	1,332	12/5/2022	12/22/2022	17	0.000%	0.0001
4000470592	27068	456	12/6/2022	12/23/2022	17	0.000%	0.0000
4000471048	25987	4,800	12/19/2022	1/5/2023	17	0.001%	0.0002
4000471053	106699	7,600	12/19/2022	1/5/2023	17	0.002%	0.0003
4000471065	128485	400	12/20/2022	1/6/2023	17	0.000%	0.0000
4000471070	142269	2,500	12/20/2022	1/6/2023	17	0.001%	0.0001
4000471077	145222	736	12/20/2022	1/6/2023	17	0.000%	0.0000
4000471054	145556	950,000	12/20/2022	1/6/2023	17	0.251%	0.0426
4000471243	8392	43,776	12/23/2022	1/9/2023	17	0.012%	0.0020
4000471250	25987	1,200	12/23/2022	1/9/2023	17	0.000%	0.0001
4000471255	27013	4,043	12/23/2022	1/9/2023	17	0.001%	0.0002
4000471226	36422	1,652	12/23/2022	1/9/2023	17	0.000%	0.0001
4000471240	208279	208	12/23/2022	1/9/2023	17	0.000%	0.0000
4000471296	26644	16,808	12/27/2022	1/13/2023	17	0.004%	0.0008
4000459646	26301	899	1/6/2022	1/24/2022	18	0.000%	0.0000
4000459648	30475	47,653	1/6/2022	1/24/2022	18	0.013%	0.0023
4000459649	30475	30,918	1/6/2022	1/24/2022	18	0.008%	0.0015
4000459614	104872	360	1/6/2022	1/24/2022	18	0.000%	0.0000
4000459636	144303	3,983	1/6/2022	1/24/2022	18	0.001%	0.0002
4000459685	25908	12,563	1/7/2022	1/25/2022	18	0.003%	0.0006
4000459688	26644	540	1/7/2022	1/25/2022	18	0.000%	0.0000
4000459713	11304	6,000	1/10/2022	1/28/2022	18	0.002%	0.0003
4000459862	13911	1,100	1/13/2022	1/31/2022	18	0.000%	0.0001
4000459866	26301	899	1/13/2022	1/31/2022	18	0.000%	0.0000
4000459871	33770	69,709	1/13/2022	1/31/2022	18	0.018%	0.0033
4000459812	4502	1,172	1/13/2022	1/31/2022	18	0.000%	0.0001
4000459813	4502	21,241	1/13/2022	1/31/2022	18	0.006%	0.0010
4000459815	5089	62,000	1/13/2022	1/31/2022	18	0.016%	0.0029

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459901	144849	408,000	1/14/2022	2/1/2022	18	0.108%	0.0194
4000459907	32921	3,121	1/14/2022	2/1/2022	18	0.001%	0.0001
4000459918	32940	128,083	1/14/2022	2/1/2022	18	0.034%	0.0061
4000459919	32941	352,930	1/14/2022	2/1/2022	18	0.093%	0.0168
4000459921	32944	51,869	1/14/2022	2/1/2022	18	0.014%	0.0025
4000459923	32947	55,192	1/14/2022	2/1/2022	18	0.015%	0.0026
4000459930	32962	8,338	1/14/2022	2/1/2022	18	0.002%	0.0004
4000459933	32967	18,300	1/14/2022	2/1/2022	18	0.005%	0.0009
4000459943	32988	1,806	1/14/2022	2/1/2022	18	0.000%	0.0001
4000459944	32989	9,952	1/14/2022	2/1/2022	18	0.003%	0.0005
4000459952	33003	13,939	1/14/2022	2/1/2022	18	0.004%	0.0007
4000460053	6031	2,900	1/20/2022	2/7/2022	18	0.001%	0.0001
4000460796	27389	9,660	2/4/2022	2/22/2022	18	0.003%	0.0005
4000460838	26363	4,758	2/7/2022	2/25/2022	18	0.001%	0.0002
4000460839	26381	1,280	2/7/2022	2/25/2022	18	0.000%	0.0001
4000460815	124628	18,617	2/7/2022	2/25/2022	18	0.005%	0.0009
4000460825	144540	69,119	2/7/2022	2/25/2022	18	0.018%	0.0033
4000460963	26644	2,700	2/10/2022	2/28/2022	18	0.001%	0.0001
4000460968	29876	4,522	2/10/2022	2/28/2022	18	0.001%	0.0002
4000460951	144807	44,137	2/10/2022	2/28/2022	18	0.012%	0.0021
4000460988	27230	52,355	2/11/2022	3/1/2022	18	0.014%	0.0025
4000460989	30580	1,530	2/11/2022	3/1/2022	18	0.000%	0.0001
4000461257	33770	63,125	2/18/2022	3/8/2022	18	0.017%	0.0030
4000461214	103131	1,997	2/18/2022	3/8/2022	18	0.001%	0.0001
4000461462	33880	14,194	2/25/2022	3/15/2022	18	0.004%	0.0007
4000461605	6031	2,554	3/3/2022	3/21/2022	18	0.001%	0.0001
4000461661	26213	966	3/4/2022	3/22/2022	18	0.000%	0.0000
4000461784	8392	10,458	3/10/2022	3/28/2022	18	0.003%	0.0005
4000461842	26323	5,268	3/11/2022	3/29/2022	18	0.001%	0.0003
4000461861	128255	2,500	3/14/2022	4/1/2022	18	0.001%	0.0001
4000461862	128707	1,000	3/14/2022	4/1/2022	18	0.000%	0.0000
4000462037	20063	4,851	3/18/2022	4/5/2022	18	0.001%	0.0002
4000462218	143189	8,318	3/25/2022	4/12/2022	18	0.002%	0.0004
4000462529	25644	25,336	4/1/2022	4/19/2022	18	0.007%	0.0012
4000462559	137912	3,859	4/4/2022	4/22/2022	18	0.001%	0.0002
4000462657	130008	28,952	4/7/2022	4/25/2022	18	0.008%	0.0014
4000462662	142942	339	4/7/2022	4/25/2022	18	0.000%	0.0000
4000462692	30580	320	4/8/2022	4/26/2022	18	0.000%	0.0000
4000462688	132103	20,600	4/8/2022	4/26/2022	18	0.005%	0.0010
4000463133	33956	2,275	4/22/2022	5/10/2022	18	0.001%	0.0001
4000463134	34173	32,085	4/22/2022	5/10/2022	18	0.008%	0.0015
4000463174	26493	13,086	4/25/2022	5/13/2022	18	0.003%	0.0006
4000463168	145038	2,500	4/25/2022	5/13/2022	18	0.001%	0.0001
4000463372	24114	770	4/29/2022	5/17/2022	18	0.000%	0.0000
4000463576	135537	36,573	5/5/2022	5/23/2022	18	0.010%	0.0017
4000463596	142942	21,675	5/6/2022	5/24/2022	18	0.006%	0.0010
4000463636	11304	9,075	5/9/2022	5/27/2022	18	0.002%	0.0004
4000463802	26643	757	5/13/2022	5/31/2022	18	0.000%	0.0000
4000463804	27982	1,150	5/13/2022	5/31/2022	18	0.000%	0.0001
4000463762	33624	3,644	5/13/2022	5/31/2022	18	0.001%	0.0002
4000463855	127836	1,000	5/16/2022	6/3/2022	18	0.000%	0.0000
4000463865	142284	2,500	5/16/2022	6/3/2022	18	0.001%	0.0001
4000463974	115663	6,018	5/19/2022	6/6/2022	18	0.002%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464295	28076	1,357	5/27/2022	6/14/2022	18	0.000%	0.0001
4000464274	142885	3,602	5/27/2022	6/14/2022	18	0.001%	0.0002
4000464491	6031	520	6/3/2022	6/21/2022	18	0.000%	0.0000
4000464504	139275	268	6/3/2022	6/21/2022	18	0.000%	0.0000
4000464561	25150	4,386	6/6/2022	6/24/2022	18	0.001%	0.0002
4000464654	142942	435	6/9/2022	6/27/2022	18	0.000%	0.0000
4000464643	125009	12,304	6/9/2022	6/27/2022	18	0.003%	0.0006
4000464718	10630	640	6/10/2022	6/28/2022	18	0.000%	0.0000
4000464771	26301	3,445	6/13/2022	7/1/2022	18	0.001%	0.0002
4000464750	144791	3,400	6/13/2022	7/1/2022	18	0.001%	0.0002
4000464977	130375	14,952	6/17/2022	7/5/2022	18	0.004%	0.0007
4000464898	6031	83	6/17/2022	7/5/2022	18	0.000%	0.0000
4000464910	116902	50,525	6/17/2022	7/5/2022	18	0.013%	0.0024
4000464996	135537	70,743	6/20/2022	7/8/2022	18	0.019%	0.0034
4000465057	35485	7,179	6/23/2022	7/11/2022	18	0.002%	0.0003
4000465219	26382	1,420	6/27/2022	7/15/2022	18	0.000%	0.0001
4000465222	26643	778	6/27/2022	7/15/2022	18	0.000%	0.0000
4000465330	142787	10,258	6/30/2022	7/18/2022	18	0.003%	0.0005
4000465450	27512	1,060	7/1/2022	7/19/2022	18	0.000%	0.0001
4000465464	34616	11,964	7/1/2022	7/19/2022	18	0.003%	0.0006
4000465397	106674	22,063	7/1/2022	7/19/2022	18	0.006%	0.0010
4000465563	134272	4,202	7/7/2022	7/25/2022	18	0.001%	0.0002
4000465782	126928	54	7/14/2022	8/1/2022	18	0.000%	0.0000
4000465860	33770	33,337	7/15/2022	8/2/2022	18	0.009%	0.0016
4000465817	29254	4,648	7/15/2022	8/2/2022	18	0.001%	0.0002
4000466007	24251	780	7/21/2022	8/8/2022	18	0.000%	0.0000
4000466084	125016	1,434	7/22/2022	8/9/2022	18	0.000%	0.0001
4000466031	123377	5,168	7/22/2022	8/9/2022	18	0.001%	0.0002
4000466233	24885	3,750	7/28/2022	8/15/2022	18	0.001%	0.0002
4000466238	26679	15,750	7/28/2022	8/15/2022	18	0.004%	0.0007
4000466208	10439	2,090	7/28/2022	8/15/2022	18	0.001%	0.0001
4000466308	26659	2,369	7/29/2022	8/16/2022	18	0.001%	0.0001
4000466312	27512	1,074	7/29/2022	8/16/2022	18	0.000%	0.0001
4000466329	33770	51,212	7/29/2022	8/16/2022	18	0.014%	0.0024
4000466391	137825	531	8/1/2022	8/19/2022	18	0.000%	0.0000
4000466349	126570	1,539	8/1/2022	8/19/2022	18	0.000%	0.0001
4000466352	139487	1,043	8/1/2022	8/19/2022	18	0.000%	0.0000
4000466511	11054	3,460	8/4/2022	8/22/2022	18	0.001%	0.0002
4000466517	27704	2,200	8/4/2022	8/22/2022	18	0.001%	0.0001
4000466518	28619	15,893	8/4/2022	8/22/2022	18	0.004%	0.0008
4000466507	144581	4,832	8/4/2022	8/22/2022	18	0.001%	0.0002
4000466508	145222	2,392	8/4/2022	8/22/2022	18	0.001%	0.0001
4000466539	134862	481,584	8/5/2022	8/23/2022	18	0.127%	0.0229
4000466593	11427	5,550	8/8/2022	8/26/2022	18	0.001%	0.0003
4000466725	6031	139	8/11/2022	8/29/2022	18	0.000%	0.0000
4000466728	33624	3,156	8/11/2022	8/29/2022	18	0.001%	0.0001
4000466746	145056	595,104	8/11/2022	8/29/2022	18	0.157%	0.0283
4000466723	107826	7,200	8/11/2022	8/29/2022	18	0.002%	0.0003
4000466773	30580	999	8/12/2022	8/30/2022	18	0.000%	0.0000
4000467024	28619	3,920	8/19/2022	9/6/2022	18	0.001%	0.0002
4000466973	6031	7,395	8/19/2022	9/6/2022	18	0.002%	0.0004
4000466976	25147	1,472,815	8/19/2022	9/6/2022	18	0.388%	0.0699
4000466982	103603	2,927	8/19/2022	9/6/2022	18	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467193	32897	2,750	8/25/2022	9/12/2022	18	0.001%	0.0001
4000467169	139089	511	8/25/2022	9/12/2022	18	0.000%	0.0000
4000467238	27162	3,400	8/26/2022	9/13/2022	18	0.001%	0.0002
4000467244	30252	10,032	8/26/2022	9/13/2022	18	0.003%	0.0005
4000467246	30475	28,496	8/26/2022	9/13/2022	18	0.008%	0.0014
4000467247	30475	11,923	8/26/2022	9/13/2022	18	0.003%	0.0006
4000467211	118989	6	8/26/2022	9/13/2022	18	0.000%	0.0000
4000467526	30475	42,190	9/2/2022	9/20/2022	18	0.011%	0.0020
4000467527	30475	47,359	9/2/2022	9/20/2022	18	0.012%	0.0022
4000467528	30475	52,066	9/2/2022	9/20/2022	18	0.014%	0.0025
4000467458	101853	963	9/2/2022	9/20/2022	18	0.000%	0.0000
4000467471	134906	3,900	9/2/2022	9/20/2022	18	0.001%	0.0002
4000467473	139275	268	9/2/2022	9/20/2022	18	0.000%	0.0000
4000467474	141021	2,700	9/2/2022	9/20/2022	18	0.001%	0.0001
4000467500	144422	22,233	9/2/2022	9/20/2022	18	0.006%	0.0011
4000467602	143312	3,765	9/8/2022	9/26/2022	18	0.001%	0.0002
4000467653	8392	12,123	9/9/2022	9/27/2022	18	0.003%	0.0006
4000467660	30475	56,636	9/9/2022	9/27/2022	18	0.015%	0.0027
4000467661	30475	43,049	9/9/2022	9/27/2022	18	0.011%	0.0020
4000467662	30475	49,103	9/9/2022	9/27/2022	18	0.013%	0.0023
4000467634	142942	21,699	9/9/2022	9/27/2022	18	0.006%	0.0010
4000467642	143741	4,950	9/9/2022	9/27/2022	18	0.001%	0.0002
4000467813	13911	3,280	9/15/2022	10/3/2022	18	0.001%	0.0002
4000468082	28619	15,792	9/23/2022	10/11/2022	18	0.004%	0.0007
4000468027	6031	1,525	9/23/2022	10/11/2022	18	0.000%	0.0001
4000468068	145193	4,250	9/23/2022	10/11/2022	18	0.001%	0.0002
4000468128	105195	6,483	9/26/2022	10/14/2022	18	0.002%	0.0003
4000468099	105195	5,711	9/26/2022	10/14/2022	18	0.002%	0.0003
4000468289	11427	9,250	9/29/2022	10/17/2022	18	0.002%	0.0004
4000468285	145208	2,204	9/29/2022	10/17/2022	18	0.001%	0.0001
4000468395	8392	35,082	9/30/2022	10/18/2022	18	0.009%	0.0017
4000468320	34888	234	9/30/2022	10/18/2022	18	0.000%	0.0000
4000468360	142874	12,939	9/30/2022	10/18/2022	18	0.003%	0.0006
4000468374	144015	10,000	9/30/2022	10/18/2022	18	0.003%	0.0005
4000468391	145193	5,850	9/30/2022	10/18/2022	18	0.002%	0.0003
4000468446	14463	11,592	10/3/2022	10/21/2022	18	0.003%	0.0006
4000468457	26382	1,584	10/3/2022	10/21/2022	18	0.000%	0.0001
4000468520	24885	1,300	10/6/2022	10/24/2022	18	0.000%	0.0001
4000468613	135537	58,023	10/7/2022	10/25/2022	18	0.015%	0.0028
4000468543	32869	15	10/7/2022	10/25/2022	18	0.000%	0.0000
4000468554	105195	7,423	10/7/2022	10/25/2022	18	0.002%	0.0004
4000468578	145388	21,083	10/7/2022	10/25/2022	18	0.006%	0.0010
4000468779	33956	2,017	10/13/2022	10/31/2022	18	0.001%	0.0001
4000468783	126165	6,774	10/13/2022	10/31/2022	18	0.002%	0.0003
4000468756	142942	2,794	10/13/2022	10/31/2022	18	0.001%	0.0001
4000468763	145056	461,771	10/13/2022	10/31/2022	18	0.122%	0.0219
4000469284	142681	204,230	10/27/2022	11/14/2022	18	0.054%	0.0097
4000469290	145208	5,684	10/27/2022	11/14/2022	18	0.001%	0.0003
4000469365	9891	4,810	10/28/2022	11/15/2022	18	0.001%	0.0002
4000469371	24113	3,463	10/28/2022	11/15/2022	18	0.001%	0.0002
4000469380	26659	3,241	10/28/2022	11/15/2022	18	0.001%	0.0002
4000469383	27982	13,108	10/28/2022	11/15/2022	18	0.003%	0.0006
4000469401	137825	110	10/28/2022	11/15/2022	18	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000469333	101853	69,799	10/28/2022	11/15/2022	18	0.018%	0.0033
4000469349	142942	24,703	10/28/2022	11/15/2022	18	0.007%	0.0012
4000469357	143606	326,444	10/28/2022	11/15/2022	18	0.086%	0.0155
4000469446	28619	24,248	10/31/2022	11/18/2022	18	0.006%	0.0012
4000469600	135537	12,688	11/3/2022	11/21/2022	18	0.003%	0.0006
4000469636	14463	30,693	11/4/2022	11/22/2022	18	0.008%	0.0015
4000469655	32897	1,500	11/4/2022	11/22/2022	18	0.000%	0.0001
4000469686	28619	9,360	11/7/2022	11/25/2022	18	0.002%	0.0004
4000469667	122492	10,000	11/7/2022	11/25/2022	18	0.003%	0.0005
4000469812	145402	4,529	11/10/2022	11/28/2022	18	0.001%	0.0002
4000469991	34348	5,190	11/17/2022	12/5/2022	18	0.001%	0.0002
4000469970	142681	122,374	11/17/2022	12/5/2022	18	0.032%	0.0058
4000470430	8392	61,527	12/1/2022	12/19/2022	18	0.016%	0.0029
4000470411	132005	1,500	12/1/2022	12/19/2022	18	0.000%	0.0001
4000470466	131989	42,426	12/2/2022	12/20/2022	18	0.011%	0.0020
4000470499	144344	9,300	12/2/2022	12/20/2022	18	0.002%	0.0004
4000470729	26453	480	12/9/2022	12/27/2022	18	0.000%	0.0000
4000470999	9891	8,808	12/16/2022	1/3/2023	18	0.002%	0.0004
4000470929	108083	20	12/16/2022	1/3/2023	18	0.000%	0.0000
4000470939	125009	5,736	12/16/2022	1/3/2023	18	0.002%	0.0003
4000470945	131647	2,525	12/16/2022	1/3/2023	18	0.001%	0.0001
4000470948	137912	4,052	12/16/2022	1/3/2023	18	0.001%	0.0002
4000470952	141086	11,000	12/16/2022	1/3/2023	18	0.003%	0.0005
4000470956	141826	20,329	12/16/2022	1/3/2023	18	0.005%	0.0010
4000470964	142926	44,246	12/16/2022	1/3/2023	18	0.012%	0.0021
4000470975	144344	4,300	12/16/2022	1/3/2023	18	0.001%	0.0002
4000470990	145056	461,771	12/16/2022	1/3/2023	18	0.122%	0.0219
4000471029	104872	47	12/19/2022	1/6/2023	18	0.000%	0.0000
4000471035	139089	388	12/19/2022	1/6/2023	18	0.000%	0.0000
4000471214	125016	2,599	12/22/2022	1/9/2023	18	0.001%	0.0001
4000471175	6031	3,169	12/22/2022	1/9/2023	18	0.001%	0.0002
4000471186	123534	34,055	12/22/2022	1/9/2023	18	0.009%	0.0016
4000471199	145208	8,258	12/22/2022	1/9/2023	18	0.002%	0.0004
4000471257	27994	7,260	12/23/2022	1/10/2023	18	0.002%	0.0003
4000471239	145222	736	12/23/2022	1/10/2023	18	0.000%	0.0000
4000471493	26642	2,659	12/30/2022	1/17/2023	18	0.001%	0.0001
4000471494	26643	1,514	12/30/2022	1/17/2023	18	0.000%	0.0001
4000471497	27704	1,600	12/30/2022	1/17/2023	18	0.000%	0.0001
4000471513	33956	9,241	12/30/2022	1/17/2023	18	0.002%	0.0004
4000471524	130375	52,008	12/30/2022	1/17/2023	18	0.014%	0.0025
4000471419	6031	918	12/30/2022	1/17/2023	18	0.000%	0.0000
4000471455	143520	2,252	12/30/2022	1/17/2023	18	0.001%	0.0001
4000471461	143880	1,800	12/30/2022	1/17/2023	18	0.000%	0.0001
4000471479	145553	1,300	12/30/2022	1/17/2023	18	0.000%	0.0001
4000459605	30475	45,867	1/5/2022	1/24/2022	19	0.012%	0.0023
4000459606	30475	58,338	1/5/2022	1/24/2022	19	0.015%	0.0029
4000459607	34173	63,876	1/5/2022	1/24/2022	19	0.017%	0.0032
4000459666	132321	3,823	1/7/2022	1/26/2022	19	0.001%	0.0002
4000459784	143994	2,940	1/12/2022	1/31/2022	19	0.001%	0.0001
4000459823	34190	28,568	1/13/2022	2/1/2022	19	0.008%	0.0014
4000459848	143994	33,843	1/13/2022	2/1/2022	19	0.009%	0.0017
4000459909	32927	272,844	1/14/2022	2/2/2022	19	0.072%	0.0137
4000459911	32929	31,061	1/14/2022	2/2/2022	19	0.008%	0.0016

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459941	32983	89,210	1/14/2022	2/2/2022	19	0.024%	0.0045
4000459951	33002	6,521	1/14/2022	2/2/2022	19	0.002%	0.0003
4000460057	24114	550	1/20/2022	2/8/2022	19	0.000%	0.0000
4000460305	106699	1,688	1/26/2022	2/14/2022	19	0.000%	0.0001
4000460278	101853	3,738	1/26/2022	2/14/2022	19	0.001%	0.0002
4000460347	32991	1,911	1/27/2022	2/15/2022	19	0.001%	0.0001
4000460474	25437	3,600	1/28/2022	2/16/2022	19	0.001%	0.0002
4000460452	26312	7,650	1/28/2022	2/16/2022	19	0.002%	0.0004
4000460757	28619	1,150	2/3/2022	2/22/2022	19	0.000%	0.0001
4000460727	101853	9,891	2/3/2022	2/22/2022	19	0.003%	0.0005
4000460731	116384	81	2/3/2022	2/22/2022	19	0.000%	0.0000
4000460793	24885	700	2/4/2022	2/23/2022	19	0.000%	0.0000
4000460809	125016	386	2/4/2022	2/23/2022	19	0.000%	0.0000
4000460779	142942	17,936	2/4/2022	2/23/2022	19	0.005%	0.0009
4000460905	24211	4,822	2/9/2022	2/28/2022	19	0.001%	0.0002
4000460933	9891	17,659	2/10/2022	3/1/2022	19	0.005%	0.0009
4000460952	0W00175	70,000	2/10/2022	3/1/2022	19	0.018%	0.0035
4000461206	101122	7,060	2/18/2022	3/9/2022	19	0.002%	0.0004
4000461207	111559	4,125	2/18/2022	3/9/2022	19	0.001%	0.0002
4000461344	23681	6,155	2/23/2022	3/14/2022	19	0.002%	0.0003
4000461417	102558	89,552	2/25/2022	3/16/2022	19	0.024%	0.0045
4000461986	8998	868	3/17/2022	4/5/2022	19	0.000%	0.0000
4000461959	4765	2,000	3/17/2022	4/5/2022	19	0.001%	0.0001
4000462035	144965	650	3/18/2022	4/6/2022	19	0.000%	0.0000
4000462343	122962	1,500	3/30/2022	4/18/2022	19	0.000%	0.0001
4000462512	144794	24,150	4/1/2022	4/20/2022	19	0.006%	0.0012
4000462627	142942	1,945	4/6/2022	4/25/2022	19	0.001%	0.0001
4000462673	145044	16,200	4/7/2022	4/26/2022	19	0.004%	0.0008
4000462644	107932	330	4/7/2022	4/26/2022	19	0.000%	0.0000
4000462645	126356	732	4/7/2022	4/26/2022	19	0.000%	0.0000
4000462699	116902	28,765	4/8/2022	4/27/2022	19	0.008%	0.0014
4000462811	110754	2,000	4/13/2022	5/2/2022	19	0.001%	0.0001
4000462826	131453	500	4/13/2022	5/2/2022	19	0.000%	0.0000
4000462849	145037	150	4/13/2022	5/2/2022	19	0.000%	0.0000
4000463005	143189	17,482	4/20/2022	5/9/2022	19	0.005%	0.0009
4000463232	11427	19,950	4/27/2022	5/16/2022	19	0.005%	0.0010
4000463209	14294	4,500	4/27/2022	5/16/2022	19	0.001%	0.0002
4000463289	145097	9,641	4/28/2022	5/17/2022	19	0.003%	0.0005
4000463260	125852	2,707	4/28/2022	5/17/2022	19	0.001%	0.0001
4000463365	8998	88,882	4/29/2022	5/18/2022	19	0.023%	0.0045
4000463370	23681	5,837	4/29/2022	5/18/2022	19	0.002%	0.0003
4000463380	26639	10,328	4/29/2022	5/18/2022	19	0.003%	0.0005
4000463387	28619	836	4/29/2022	5/18/2022	19	0.000%	0.0000
4000463393	32245	36	4/29/2022	5/18/2022	19	0.000%	0.0000
4000463563	142942	957	5/5/2022	5/24/2022	19	0.000%	0.0000
4000463951	24292	3,648	5/18/2022	6/6/2022	19	0.001%	0.0002
4000464169	26493	12,838	5/25/2022	6/13/2022	19	0.003%	0.0006
4000464217	26490	1,204	5/26/2022	6/14/2022	19	0.000%	0.0001
4000464193	140083	5,000	5/26/2022	6/14/2022	19	0.001%	0.0003
4000464478	28619	2,042	6/2/2022	6/21/2022	19	0.001%	0.0001
4000464456	143929	75,124	6/2/2022	6/21/2022	19	0.020%	0.0038
4000464518	144422	43,730	6/3/2022	6/22/2022	19	0.012%	0.0022
4000464621	126107	40,000	6/8/2022	6/27/2022	19	0.011%	0.0020

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464626	142942	5,269	6/8/2022	6/27/2022	19	0.001%	0.0003
4000464666	23681	2,441	6/9/2022	6/28/2022	19	0.001%	0.0001
4000464667	25173	3,850	6/9/2022	6/28/2022	19	0.001%	0.0002
4000464670	30252	19,780	6/9/2022	6/28/2022	19	0.005%	0.0010
4000464728	28619	7,315	6/10/2022	6/29/2022	19	0.002%	0.0004
4000464896	34616	3,883	6/16/2022	7/5/2022	19	0.001%	0.0002
4000465106	126165	4,592	6/23/2022	7/12/2022	19	0.001%	0.0002
4000465065	110398	2,500	6/23/2022	7/12/2022	19	0.001%	0.0001
4000465157	26490	1,167	6/24/2022	7/13/2022	19	0.000%	0.0001
4000465169	34173	6,779	6/24/2022	7/13/2022	19	0.002%	0.0003
4000465125	124628	6,304	6/24/2022	7/13/2022	19	0.002%	0.0003
4000465137	143991	4,505	6/24/2022	7/13/2022	19	0.001%	0.0002
4000465374	34616	21,886	6/30/2022	7/19/2022	19	0.006%	0.0011
4000465411	141583	522	7/1/2022	7/20/2022	19	0.000%	0.0000
4000465412	142681	389,622	7/1/2022	7/20/2022	19	0.103%	0.0195
4000465561	125016	1,524	7/7/2022	7/26/2022	19	0.000%	0.0001
4000465597	11631	6,500	7/8/2022	7/27/2022	19	0.002%	0.0003
4000465582	142942	29,393	7/8/2022	7/27/2022	19	0.008%	0.0015
4000465588	144422	25,130	7/8/2022	7/27/2022	19	0.007%	0.0013
4000465966	9891	7,098	7/20/2022	8/8/2022	19	0.002%	0.0004
4000466054	11054	3,713	7/22/2022	8/10/2022	19	0.001%	0.0002
4000466072	28619	3,344	7/22/2022	8/10/2022	19	0.001%	0.0002
4000466075	30475	91,719	7/22/2022	8/10/2022	19	0.024%	0.0046
4000466037	142681	97,264	7/22/2022	8/10/2022	19	0.026%	0.0049
4000466049	145056	595,104	7/22/2022	8/10/2022	19	0.157%	0.0298
4000466202	133368	5,000	7/28/2022	8/16/2022	19	0.001%	0.0003
4000466203	133368	5,580	7/28/2022	8/16/2022	19	0.001%	0.0003
4000466204	133368	8,328	7/28/2022	8/16/2022	19	0.002%	0.0004
4000466205	133368	37,200	7/28/2022	8/16/2022	19	0.010%	0.0019
4000466206	133368	10,000	7/28/2022	8/16/2022	19	0.003%	0.0005
4000466258	11427	11,900	7/29/2022	8/17/2022	19	0.003%	0.0006
4000466280	142942	21,536	7/29/2022	8/17/2022	19	0.006%	0.0011
4000466459	143189	15,503	8/3/2022	8/22/2022	19	0.004%	0.0008
4000466479	32966	5,119	8/3/2022	8/22/2022	19	0.001%	0.0003
4000466512	18267	8,914	8/4/2022	8/23/2022	19	0.002%	0.0004
4000466529	9891	2,080	8/5/2022	8/24/2022	19	0.001%	0.0001
4000466682	30252	8,208	8/10/2022	8/29/2022	19	0.002%	0.0004
4000466660	130224	700	8/10/2022	8/29/2022	19	0.000%	0.0000
4000466747	9673	2,975	8/11/2022	8/30/2022	19	0.001%	0.0001
4000466764	32808	1,980	8/11/2022	8/30/2022	19	0.001%	0.0001
4000466815	34531	12,506	8/12/2022	8/31/2022	19	0.003%	0.0006
4000466790	141583	1,177	8/12/2022	8/31/2022	19	0.000%	0.0001
4000466967	28619	836	8/18/2022	9/6/2022	19	0.000%	0.0000
4000467016	23681	1,592	8/19/2022	9/7/2022	19	0.000%	0.0001
4000467021	26644	1,620	8/19/2022	9/7/2022	19	0.000%	0.0001
4000467135	11536	34,851	8/24/2022	9/12/2022	19	0.009%	0.0017
4000467141	30068	413	8/24/2022	9/12/2022	19	0.000%	0.0000
4000467151	135537	32,403	8/24/2022	9/12/2022	19	0.009%	0.0016
4000467249	34616	23,972	8/26/2022	9/14/2022	19	0.006%	0.0012
4000467373	25644	8,871	8/31/2022	9/19/2022	19	0.002%	0.0004
4000467341	101063	1,000	8/31/2022	9/19/2022	19	0.000%	0.0001
4000467423	11427	7,050	9/1/2022	9/20/2022	19	0.002%	0.0004
4000467400	103603	2,195	9/1/2022	9/20/2022	19	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467417	144422	20,960	9/1/2022	9/20/2022	19	0.006%	0.0011
4000467610	8392	17,140	9/8/2022	9/27/2022	19	0.005%	0.0009
4000467600	142942	598	9/8/2022	9/27/2022	19	0.000%	0.0000
4000467657	26493	224	9/9/2022	9/28/2022	19	0.000%	0.0000
4000467649	145056	461,771	9/9/2022	9/28/2022	19	0.122%	0.0231
4000468025	125016	896	9/22/2022	10/11/2022	19	0.000%	0.0000
4000468007	145193	530	9/22/2022	10/11/2022	19	0.000%	0.0000
4000468089	34341	24,425	9/23/2022	10/12/2022	19	0.006%	0.0012
4000468031	26312	22,950	9/23/2022	10/12/2022	19	0.006%	0.0012
4000468056	140456	500	9/23/2022	10/12/2022	19	0.000%	0.0000
4000468290	11536	8,035	9/29/2022	10/18/2022	19	0.002%	0.0004
4000468301	28619	2,072	9/29/2022	10/18/2022	19	0.001%	0.0001
4000468401	18267	9,154	9/30/2022	10/19/2022	19	0.002%	0.0005
4000468423	105195	6,136	9/30/2022	10/19/2022	19	0.002%	0.0003
4000468323	103603	1,464	9/30/2022	10/19/2022	19	0.000%	0.0001
4000468325	105195	14,948	9/30/2022	10/19/2022	19	0.004%	0.0007
4000468334	116902	550	9/30/2022	10/19/2022	19	0.000%	0.0000
4000468362	142942	23,811	9/30/2022	10/19/2022	19	0.006%	0.0012
4000468377	144421	47,985	9/30/2022	10/19/2022	19	0.013%	0.0024
4000468392	145222	3,680	9/30/2022	10/19/2022	19	0.001%	0.0002
4000468494	24211	5,000	10/5/2022	10/24/2022	19	0.001%	0.0003
4000468524	26301	899	10/6/2022	10/25/2022	19	0.000%	0.0000
4000468596	30124	1,610	10/7/2022	10/26/2022	19	0.000%	0.0001
4000468614	137825	9	10/7/2022	10/26/2022	19	0.000%	0.0000
4000468558	116902	1,000	10/7/2022	10/26/2022	19	0.000%	0.0001
4000468723	23681	5,094	10/12/2022	10/31/2022	19	0.001%	0.0003
4000468740	135537	50,093	10/12/2022	10/31/2022	19	0.013%	0.0025
4000468709	142391	3,500	10/12/2022	10/31/2022	19	0.001%	0.0002
4000468710	142942	4,279	10/12/2022	10/31/2022	19	0.001%	0.0002
4000468790	29254	5,423	10/14/2022	11/2/2022	19	0.001%	0.0003
4000469019	33092	990	10/19/2022	11/7/2022	19	0.000%	0.0000
4000469058	23681	4,245	10/20/2022	11/8/2022	19	0.001%	0.0002
4000469115	28619	23,016	10/21/2022	11/9/2022	19	0.006%	0.0012
4000469118	30475	43,914	10/21/2022	11/9/2022	19	0.012%	0.0022
4000469119	30475	30,876	10/21/2022	11/9/2022	19	0.008%	0.0015
4000469107	145293	7,346	10/21/2022	11/9/2022	19	0.002%	0.0004
4000469237	23681	3,820	10/26/2022	11/14/2022	19	0.001%	0.0002
4000469222	128463	500	10/26/2022	11/14/2022	19	0.000%	0.0000
4000469303	26381	202,240	10/27/2022	11/15/2022	19	0.053%	0.0101
4000469281	141583	420	10/27/2022	11/15/2022	19	0.000%	0.0000
4000469285	142942	753	10/27/2022	11/15/2022	19	0.000%	0.0000
4000469379	26643	263	10/28/2022	11/16/2022	19	0.000%	0.0000
4000469336	107047	25,168	10/28/2022	11/16/2022	19	0.007%	0.0013
4000469816	24211	5,353	11/10/2022	11/29/2022	19	0.001%	0.0003
4000469819	26493	1,974	11/10/2022	11/29/2022	19	0.001%	0.0001
4000469780	30580	4,147	11/10/2022	11/29/2022	19	0.001%	0.0002
4000469799	143111	6,200	11/10/2022	11/29/2022	19	0.002%	0.0003
4000469920	11304	600	11/16/2022	12/5/2022	19	0.000%	0.0000
4000469909	117374	2,500	11/16/2022	12/5/2022	19	0.001%	0.0001
4000469911	134862	38,639	11/16/2022	12/5/2022	19	0.010%	0.0019
4000470005	104261	1,126	11/18/2022	12/7/2022	19	0.000%	0.0001
4000470197	11054	3,831	11/23/2022	12/12/2022	19	0.001%	0.0002
4000470226	125016	14,341	11/23/2022	12/12/2022	19	0.004%	0.0007

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470227	135497	21,200	11/23/2022	12/12/2022	19	0.006%	0.0011
4000470148	6031	48,041	11/23/2022	12/12/2022	19	0.013%	0.0024
4000470162	124628	4,956	11/23/2022	12/12/2022	19	0.001%	0.0002
4000470169	141346	134,312	11/23/2022	12/12/2022	19	0.035%	0.0067
4000470368	28619	5,768	11/30/2022	12/19/2022	19	0.002%	0.0003
4000470407	123915	885	12/1/2022	12/20/2022	19	0.000%	0.0000
4000470463	126715	10,500	12/2/2022	12/21/2022	19	0.003%	0.0005
4000470653	102553	5,828	12/8/2022	12/27/2022	19	0.002%	0.0003
4000470696	10439	729	12/9/2022	12/28/2022	19	0.000%	0.0000
4000470916	125360	5,155	12/15/2022	1/3/2023	19	0.001%	0.0003
4000471024	130375	3,726	12/16/2022	1/4/2023	19	0.001%	0.0002
4000470958	142002	7,835	12/16/2022	1/4/2023	19	0.002%	0.0004
4000470960	142164	5,356	12/16/2022	1/4/2023	19	0.001%	0.0003
4000470977	144567	5,550	12/16/2022	1/4/2023	19	0.001%	0.0003
4000470978	144567	22,856	12/16/2022	1/4/2023	19	0.006%	0.0011
4000470979	144567	25,870	12/16/2022	1/4/2023	19	0.007%	0.0013
4000470980	144567	26,833	12/16/2022	1/4/2023	19	0.007%	0.0013
4000470997	145541	3,120	12/16/2022	1/4/2023	19	0.001%	0.0002
4000471141	11536	14,638	12/21/2022	1/9/2023	19	0.004%	0.0007
4000471204	25599	882	12/22/2022	1/10/2023	19	0.000%	0.0000
4000471179	104872	28	12/22/2022	1/10/2023	19	0.000%	0.0000
4000471192	142942	1,285	12/22/2022	1/10/2023	19	0.000%	0.0001
4000471256	27704	4,750	12/23/2022	1/11/2023	19	0.001%	0.0002
4000471263	34616	1,517	12/23/2022	1/11/2023	19	0.000%	0.0001
4000471241	116971	3,000	12/23/2022	1/11/2023	19	0.001%	0.0002
4000471242	116971	3,000	12/23/2022	1/11/2023	19	0.001%	0.0002
4000471374	13911	66,000	12/29/2022	1/17/2023	19	0.017%	0.0033
4000471380	24211	4,747	12/29/2022	1/17/2023	19	0.001%	0.0002
4000471396	26453	3,280	12/29/2022	1/17/2023	19	0.001%	0.0002
4000471405	28619	10,832	12/29/2022	1/17/2023	19	0.003%	0.0005
4000471342	13911	1,140	12/29/2022	1/17/2023	19	0.000%	0.0001
4000471481	8392	12,538	12/30/2022	1/18/2023	19	0.003%	0.0006
4000471490	25987	1,600	12/30/2022	1/18/2023	19	0.000%	0.0001
4000471491	26363	1,817	12/30/2022	1/18/2023	19	0.000%	0.0001
4000471427	32138	5,739	12/30/2022	1/18/2023	19	0.002%	0.0003
4000471464	143994	29,528	12/30/2022	1/18/2023	19	0.008%	0.0015
4000471476	145510	41,958	12/30/2022	1/18/2023	19	0.011%	0.0021
4000471477	145512	4,100	12/30/2022	1/18/2023	19	0.001%	0.0002
4000459586	27389	15,410	1/4/2022	1/24/2022	20	0.004%	0.0008
4000459587	30475	29,843	1/4/2022	1/24/2022	20	0.008%	0.0016
4000459588	30475	39,121	1/4/2022	1/24/2022	20	0.010%	0.0021
4000459596	139089	92	1/5/2022	1/25/2022	20	0.000%	0.0000
4000459681	25029	1,768	1/7/2022	1/27/2022	20	0.000%	0.0001
4000459682	25395	560	1/7/2022	1/27/2022	20	0.000%	0.0000
4000459696	126165	4,970	1/7/2022	1/27/2022	20	0.001%	0.0003
4000459826	101853	4,003	1/13/2022	2/2/2022	20	0.001%	0.0002
4000459855	144741	4,046	1/13/2022	2/2/2022	20	0.001%	0.0002
4000459920	32942	2,341	1/14/2022	2/3/2022	20	0.001%	0.0001
4000460007	34173	5,175	1/18/2022	2/7/2022	20	0.001%	0.0003
4000460113	123377	4,721	1/21/2022	2/10/2022	20	0.001%	0.0002
4000460276	144401	2,500	1/26/2022	2/15/2022	20	0.001%	0.0001
4000460712	28619	836	2/2/2022	2/22/2022	20	0.000%	0.0000
4000460694	139275	541	2/2/2022	2/22/2022	20	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460722	107151	11,880	2/3/2022	2/23/2022	20	0.003%	0.0006
4000460794	26323	11,073	2/4/2022	2/24/2022	20	0.003%	0.0006
4000460772	116902	3,900	2/4/2022	2/24/2022	20	0.001%	0.0002
4000460775	123915	715	2/4/2022	2/24/2022	20	0.000%	0.0000
4000461124	131631	3,500	2/16/2022	3/8/2022	20	0.001%	0.0002
4000461132	141754	23,000	2/16/2022	3/8/2022	20	0.006%	0.0012
4000461534	28619	1,672	3/1/2022	3/21/2022	20	0.000%	0.0001
4000461526	143189	35,356	3/1/2022	3/21/2022	20	0.009%	0.0019
4000461545	30580	238	3/2/2022	3/22/2022	20	0.000%	0.0000
4000461552	131647	2,338	3/2/2022	3/22/2022	20	0.001%	0.0001
4000461617	144031	97	3/3/2022	3/23/2022	20	0.000%	0.0000
4000461782	144540	69,890	3/10/2022	3/30/2022	20	0.018%	0.0037
4000461896	144970	500	3/15/2022	4/4/2022	20	0.000%	0.0000
4000461929	100893	2,419	3/16/2022	4/5/2022	20	0.001%	0.0001
4000461970	116902	3,850	3/17/2022	4/6/2022	20	0.001%	0.0002
4000462003	107151	3,471	3/18/2022	4/7/2022	20	0.001%	0.0002
4000462004	107151	2,601	3/18/2022	4/7/2022	20	0.001%	0.0001
4000462137	125016	1,793	3/22/2022	4/11/2022	20	0.000%	0.0001
4000462124	139089	347	3/22/2022	4/11/2022	20	0.000%	0.0000
4000462198	142156	5,000	3/25/2022	4/14/2022	20	0.001%	0.0003
4000462450	27493	1,170	3/31/2022	4/20/2022	20	0.000%	0.0001
4000462491	123383	16,833	4/1/2022	4/21/2022	20	0.004%	0.0009
4000462608	142942	6,122	4/5/2022	4/25/2022	20	0.002%	0.0003
4000462596	127614	68,450	4/5/2022	4/25/2022	20	0.018%	0.0036
4000462728	25029	1,040	4/8/2022	4/28/2022	20	0.000%	0.0001
4000462895	9891	14,056	4/14/2022	5/4/2022	20	0.004%	0.0007
4000462901	24885	700	4/14/2022	5/4/2022	20	0.000%	0.0000
4000462927	34616	8,332	4/14/2022	5/4/2022	20	0.002%	0.0004
4000462983	26643	7,505	4/19/2022	5/9/2022	20	0.002%	0.0004
4000462986	28084	11,970	4/19/2022	5/9/2022	20	0.003%	0.0006
4000463141	125016	1,076	4/22/2022	5/12/2022	20	0.000%	0.0001
4000463180	11427	4,200	4/26/2022	5/16/2022	20	0.001%	0.0002
4000463294	14463	8,376	4/28/2022	5/18/2022	20	0.002%	0.0004
4000463317	28619	7,372	4/28/2022	5/18/2022	20	0.002%	0.0004
4000463363	144974	1,861	4/29/2022	5/19/2022	20	0.000%	0.0001
4000463466	131305	48,790	5/3/2022	5/23/2022	20	0.013%	0.0026
4000463516	25147	212,626	5/4/2022	5/24/2022	20	0.056%	0.0112
4000463524	142942	3,753	5/4/2022	5/24/2022	20	0.001%	0.0002
4000463544	115663	4,987	5/5/2022	5/25/2022	20	0.001%	0.0003
4000463611	13911	1,505	5/6/2022	5/26/2022	20	0.000%	0.0001
4000463623	34616	3,715	5/6/2022	5/26/2022	20	0.001%	0.0002
4000463580	29254	8,070	5/6/2022	5/26/2022	20	0.002%	0.0004
4000463746	144422	2,096	5/12/2022	6/1/2022	20	0.001%	0.0001
4000463795	24885	1,750	5/13/2022	6/2/2022	20	0.000%	0.0001
4000463962	28619	28,842	5/18/2022	6/7/2022	20	0.008%	0.0015
4000463998	11304	10,200	5/19/2022	6/8/2022	20	0.003%	0.0005
4000464045	8998	96,933	5/20/2022	6/9/2022	20	0.026%	0.0051
4000464117	25908	2,750	5/24/2022	6/13/2022	20	0.001%	0.0001
4000464160	10630	3,840	5/25/2022	6/14/2022	20	0.001%	0.0002
4000464399	24885	2,800	6/1/2022	6/21/2022	20	0.001%	0.0001
4000464472	24211	4,907	6/2/2022	6/22/2022	20	0.001%	0.0003
4000464441	141831	11,647	6/2/2022	6/22/2022	20	0.003%	0.0006
4000464540	34616	34,500	6/3/2022	6/23/2022	20	0.009%	0.0018

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464541	34616	29,713	6/3/2022	6/23/2022	20	0.008%	0.0016
4000464494	30494	855	6/3/2022	6/23/2022	20	0.000%	0.0000
4000464525	145059	2,000	6/3/2022	6/23/2022	20	0.001%	0.0001
4000464582	142942	4,021	6/7/2022	6/27/2022	20	0.001%	0.0002
4000464736	34531	18,567	6/10/2022	6/30/2022	20	0.005%	0.0010
4000464677	107932	100	6/10/2022	6/30/2022	20	0.000%	0.0000
4000464863	34616	1,123	6/15/2022	7/5/2022	20	0.000%	0.0001
4000464824	108679	3,000	6/15/2022	7/5/2022	20	0.001%	0.0002
4000464840	144415	3,500	6/15/2022	7/5/2022	20	0.001%	0.0002
4000464912	123915	1,805	6/17/2022	7/7/2022	20	0.000%	0.0001
4000465101	34173	13,817	6/23/2022	7/13/2022	20	0.004%	0.0007
4000465066	111559	7,952	6/23/2022	7/13/2022	20	0.002%	0.0004
4000465153	24885	5,550	6/24/2022	7/14/2022	20	0.001%	0.0003
4000465167	32896	950	6/24/2022	7/14/2022	20	0.000%	0.0001
4000465378	135537	38,843	6/30/2022	7/20/2022	20	0.010%	0.0020
4000465307	112215	5,456	6/30/2022	7/20/2022	20	0.001%	0.0003
4000465528	125016	359	7/6/2022	7/26/2022	20	0.000%	0.0000
4000465544	142942	1,636	7/7/2022	7/27/2022	20	0.000%	0.0001
4000465598	13534	11,998	7/8/2022	7/28/2022	20	0.003%	0.0006
4000465863	34616	5,515	7/15/2022	8/4/2022	20	0.001%	0.0003
4000465910	26643	714	7/19/2022	8/8/2022	20	0.000%	0.0000
4000465943	27466	2,896	7/20/2022	8/9/2022	20	0.001%	0.0002
4000465953	142681	356,888	7/20/2022	8/9/2022	20	0.094%	0.0188
4000465995	142681	194,528	7/21/2022	8/10/2022	20	0.051%	0.0103
4000466055	11304	13,050	7/22/2022	8/11/2022	20	0.003%	0.0007
4000466060	24292	1,737	7/22/2022	8/11/2022	20	0.000%	0.0001
4000466230	23681	1,380	7/28/2022	8/17/2022	20	0.000%	0.0001
4000466223	142942	643	7/28/2022	8/17/2022	20	0.000%	0.0000
4000466435	26643	1,135	8/2/2022	8/22/2022	20	0.000%	0.0001
4000466472	34616	5,413	8/3/2022	8/23/2022	20	0.001%	0.0003
4000466510	9891	4,069	8/4/2022	8/24/2022	20	0.001%	0.0002
4000466628	139275	201	8/9/2022	8/29/2022	20	0.000%	0.0000
4000466631	143189	12,123	8/9/2022	8/29/2022	20	0.003%	0.0006
4000466633	144422	34,936	8/9/2022	8/29/2022	20	0.009%	0.0018
4000466736	141346	134,310	8/11/2022	8/31/2022	20	0.035%	0.0071
4000467013	13911	2,090	8/19/2022	9/8/2022	20	0.001%	0.0001
4000466988	124628	68,272	8/19/2022	9/8/2022	20	0.018%	0.0036
4000467089	122574	392	8/23/2022	9/12/2022	20	0.000%	0.0000
4000467195	34616	28,603	8/25/2022	9/14/2022	20	0.008%	0.0015
4000467242	28619	16,572	8/26/2022	9/15/2022	20	0.004%	0.0009
4000467306	143520	2,216	8/30/2022	9/19/2022	20	0.001%	0.0001
4000467425	13911	71,070	9/1/2022	9/21/2022	20	0.019%	0.0037
4000467453	9891	1,183	9/2/2022	9/22/2022	20	0.000%	0.0001
4000467514	145330	3,441	9/2/2022	9/22/2022	20	0.001%	0.0002
4000467575	142942	911	9/7/2022	9/27/2022	20	0.000%	0.0000
4000467714	111665	4,000	9/14/2022	10/4/2022	20	0.001%	0.0002
4000467955	103603	2,195	9/21/2022	10/11/2022	20	0.001%	0.0001
4000467965	142311	456	9/21/2022	10/11/2022	20	0.000%	0.0000
4000467973	145376	2,333	9/21/2022	10/11/2022	20	0.001%	0.0001
4000468010	13911	3,680	9/22/2022	10/12/2022	20	0.001%	0.0002
4000468153	25029	6,968	9/27/2022	10/17/2022	20	0.002%	0.0004
4000468161	34616	1,225	9/27/2022	10/17/2022	20	0.000%	0.0001
4000468162	34779	596,170	9/27/2022	10/17/2022	20	0.157%	0.0314

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468131	11427	47,700	9/27/2022	10/17/2022	20	0.013%	0.0025
4000468254	28619	4,326	9/28/2022	10/18/2022	20	0.001%	0.0002
4000468195	14294	2,500	9/28/2022	10/18/2022	20	0.001%	0.0001
4000468276	142942	4,128	9/29/2022	10/19/2022	20	0.001%	0.0002
4000468402	23681	2,122	9/30/2022	10/20/2022	20	0.001%	0.0001
4000468315	22798	13,358	9/30/2022	10/20/2022	20	0.004%	0.0007
4000468316	22798	42,703	9/30/2022	10/20/2022	20	0.011%	0.0023
4000468353	142002	6,931	9/30/2022	10/20/2022	20	0.002%	0.0004
4000468393	145245	11,043	9/30/2022	10/20/2022	20	0.003%	0.0006
4000468484	125016	1,972	10/4/2022	10/24/2022	20	0.001%	0.0001
4000468495	25029	520	10/5/2022	10/25/2022	20	0.000%	0.0000
4000468500	135537	95,773	10/5/2022	10/25/2022	20	0.025%	0.0051
4000468530	28619	952	10/6/2022	10/26/2022	20	0.000%	0.0001
4000468581	11427	4,900	10/7/2022	10/27/2022	20	0.001%	0.0003
4000468630	142942	18,862	10/11/2022	10/31/2022	20	0.005%	0.0010
4000468689	113250	500	10/12/2022	11/1/2022	20	0.000%	0.0000
4000468719	145408	5,000	10/12/2022	11/1/2022	20	0.001%	0.0003
4000468764	145100	681	10/13/2022	11/2/2022	20	0.000%	0.0000
4000469097	142621	2,500	10/21/2022	11/10/2022	20	0.001%	0.0001
4000469302	26299	682	10/27/2022	11/16/2022	20	0.000%	0.0000
4000469309	26643	1,802	10/27/2022	11/16/2022	20	0.000%	0.0001
4000469257	116138	100	10/27/2022	11/16/2022	20	0.000%	0.0000
4000469366	11304	18,900	10/28/2022	11/17/2022	20	0.005%	0.0010
4000469376	26301	9,437	10/28/2022	11/17/2022	20	0.002%	0.0005
4000469493	116051	100	11/2/2022	11/22/2022	20	0.000%	0.0000
4000469501	137912	4,052	11/2/2022	11/22/2022	20	0.001%	0.0002
4000469827	34616	14,711	11/10/2022	11/30/2022	20	0.004%	0.0008
4000469832	135537	8,563	11/10/2022	11/30/2022	20	0.002%	0.0005
4000469772	142073	400	11/10/2022	11/30/2022	20	0.000%	0.0000
4000469894	24885	3,050	11/15/2022	12/5/2022	20	0.001%	0.0002
4000469938	30252	12,880	11/16/2022	12/6/2022	20	0.003%	0.0007
4000469904	29254	4,971	11/16/2022	12/6/2022	20	0.001%	0.0003
4000470043	28619	5,712	11/18/2022	12/8/2022	20	0.002%	0.0003
4000470018	143477	2,035	11/18/2022	12/8/2022	20	0.001%	0.0001
4000470196	9891	9,016	11/23/2022	12/13/2022	20	0.002%	0.0005
4000470172	142942	37,385	11/23/2022	12/13/2022	20	0.010%	0.0020
4000470371	32356	1,558	11/30/2022	12/20/2022	20	0.000%	0.0001
4000470314	25266	617	11/30/2022	12/20/2022	20	0.000%	0.0000
4000470341	145105	50,600	11/30/2022	12/20/2022	20	0.013%	0.0027
4000470432	11304	3,300	12/1/2022	12/21/2022	20	0.001%	0.0002
4000470449	134485	37,268	12/1/2022	12/21/2022	20	0.010%	0.0020
4000470506	144858	400	12/2/2022	12/22/2022	20	0.000%	0.0000
4000470647	125016	1,210	12/7/2022	12/27/2022	20	0.000%	0.0001
4000470601	9891	1,001	12/7/2022	12/27/2022	20	0.000%	0.0001
4000470726	25659	13,808	12/9/2022	12/29/2022	20	0.004%	0.0007
4000470739	34173	13,352	12/9/2022	12/29/2022	20	0.004%	0.0007
4000470865	34393	4,800	12/14/2022	1/3/2023	20	0.001%	0.0003
4000470910	28619	7,112	12/15/2022	1/4/2023	20	0.002%	0.0004
4000470915	34348	4,650	12/15/2022	1/4/2023	20	0.001%	0.0002
4000470898	144567	2,663	12/15/2022	1/4/2023	20	0.001%	0.0001
4000471007	27389	5,923	12/16/2022	1/5/2023	20	0.002%	0.0003
4000471022	106699	3,921	12/16/2022	1/5/2023	20	0.001%	0.0002
4000470971	143807	1,400	12/16/2022	1/5/2023	20	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470983	144858	500	12/16/2022	1/5/2023	20	0.000%	0.0000
4000470985	144898	19,404	12/16/2022	1/5/2023	20	0.005%	0.0010
4000470998	145545	1,140	12/16/2022	1/5/2023	20	0.000%	0.0001
4000471105	125360	2,940	12/20/2022	1/9/2023	20	0.001%	0.0002
4000471106	137825	511	12/20/2022	1/9/2023	20	0.000%	0.0000
4000471056	25147	475,220	12/20/2022	1/9/2023	20	0.125%	0.0251
4000471121	126928	75	12/21/2022	1/10/2023	20	0.000%	0.0000
4000471125	142942	995	12/21/2022	1/10/2023	20	0.000%	0.0001
4000471213	34616	1,517	12/22/2022	1/11/2023	20	0.000%	0.0001
4000471215	114121	3,460	12/23/2022	1/12/2023	20	0.001%	0.0002
4000471216	114121	3,460	12/23/2022	1/12/2023	20	0.001%	0.0002
4000471217	114121	3,460	12/23/2022	1/12/2023	20	0.001%	0.0002
4000471327	28619	7,088	12/28/2022	1/17/2023	20	0.002%	0.0004
4000471337	130375	68,340	12/28/2022	1/17/2023	20	0.018%	0.0036
4000471346	32138	4,152	12/29/2022	1/18/2023	20	0.001%	0.0002
4000471365	145501	1,202	12/29/2022	1/18/2023	20	0.000%	0.0001
4000471500	28619	10,752	12/30/2022	1/19/2023	20	0.003%	0.0006
4000471467	144849	113,304	12/30/2022	1/19/2023	20	0.030%	0.0060
4000459560	34173	10,319	1/3/2022	1/24/2022	21	0.003%	0.0006
4000459672	11304	7,200	1/7/2022	1/28/2022	21	0.002%	0.0004
4000459678	20063	3,025	1/7/2022	1/28/2022	21	0.001%	0.0002
4000459679	24251	9,750	1/7/2022	1/28/2022	21	0.003%	0.0005
4000459694	106699	15,974	1/7/2022	1/28/2022	21	0.004%	0.0009
4000459659	20063	3,872	1/7/2022	1/28/2022	21	0.001%	0.0002
4000459726	26301	5,543	1/10/2022	1/31/2022	21	0.001%	0.0003
4000459738	126165	1,751	1/10/2022	1/31/2022	21	0.000%	0.0001
4000459794	25905	2,000	1/12/2022	2/2/2022	21	0.001%	0.0001
4000459777	25266	7,756	1/12/2022	2/2/2022	21	0.002%	0.0004
4000460008	34616	10,536	1/18/2022	2/8/2022	21	0.003%	0.0006
4000459961	30580	1,399	1/18/2022	2/8/2022	21	0.000%	0.0001
4000459953	107932	330	1/18/2022	2/8/2022	21	0.000%	0.0000
4000460120	26644	17,550	1/21/2022	2/11/2022	21	0.005%	0.0010
4000460310	10439	825	1/27/2022	2/17/2022	21	0.000%	0.0000
4000460668	28619	1,672	2/1/2022	2/22/2022	21	0.000%	0.0001
4000460637	141021	2,700	2/1/2022	2/22/2022	21	0.001%	0.0001
4000460720	125016	359	2/2/2022	2/23/2022	21	0.000%	0.0000
4000460696	142942	3,216	2/2/2022	2/23/2022	21	0.001%	0.0002
4000460702	144344	5,000	2/2/2022	2/23/2022	21	0.001%	0.0003
4000460705	144573	4,000	2/2/2022	2/23/2022	21	0.001%	0.0002
4000460787	8998	310	2/4/2022	2/25/2022	21	0.000%	0.0000
4000460808	34531	10,149	2/4/2022	2/25/2022	21	0.003%	0.0006
4000460955	24191	607	2/10/2022	3/3/2022	21	0.000%	0.0000
4000460987	26588	840	2/11/2022	3/4/2022	21	0.000%	0.0000
4000461157	106699	477	2/16/2022	3/9/2022	21	0.000%	0.0000
4000461112	108041	500	2/16/2022	3/9/2022	21	0.000%	0.0000
4000461123	130191	750	2/16/2022	3/9/2022	21	0.000%	0.0000
4000461241	8998	21,077	2/18/2022	3/11/2022	21	0.006%	0.0012
4000461237	142942	30,022	2/18/2022	3/11/2022	21	0.008%	0.0017
4000461402	34616	13,905	2/24/2022	3/17/2022	21	0.004%	0.0008
4000461371	11427	21,000	2/24/2022	3/17/2022	21	0.006%	0.0012
4000461510	28619	1,672	2/28/2022	3/21/2022	21	0.000%	0.0001
4000461479	109140	10,000	2/28/2022	3/21/2022	21	0.003%	0.0006
4000461492	143511	1,000	2/28/2022	3/21/2022	21	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461594	24885	4,550	3/2/2022	3/23/2022	21	0.001%	0.0003
4000461536	107932	500	3/2/2022	3/23/2022	21	0.000%	0.0000
4000461632	125016	2,106	3/3/2022	3/24/2022	21	0.001%	0.0001
4000461689	118090	1,600	3/7/2022	3/28/2022	21	0.000%	0.0001
4000461690	118664	1,000	3/7/2022	3/28/2022	21	0.000%	0.0001
4000461735	135537	14,436	3/8/2022	3/29/2022	21	0.004%	0.0008
4000461754	23681	3,184	3/9/2022	3/30/2022	21	0.001%	0.0002
4000461752	144966	1,000	3/9/2022	3/30/2022	21	0.000%	0.0001
4000461898	8998	14,301	3/15/2022	4/5/2022	21	0.004%	0.0008
4000461904	24114	1,650	3/15/2022	4/5/2022	21	0.000%	0.0001
4000462047	27677	44,000	3/18/2022	4/8/2022	21	0.012%	0.0024
4000462092	25029	5,460	3/21/2022	4/11/2022	21	0.001%	0.0003
4000462113	125016	3,737	3/21/2022	4/11/2022	21	0.001%	0.0002
4000462156	11427	11,950	3/23/2022	4/13/2022	21	0.003%	0.0007
4000462157	24251	7,200	3/23/2022	4/13/2022	21	0.002%	0.0004
4000462229	23681	5,837	3/25/2022	4/15/2022	21	0.002%	0.0003
4000462236	34173	10,868	3/25/2022	4/15/2022	21	0.003%	0.0006
4000462205	30580	3,974	3/25/2022	4/15/2022	21	0.001%	0.0002
4000462325	100893	5,317	3/30/2022	4/20/2022	21	0.001%	0.0003
4000462364	143435	1,000	3/30/2022	4/20/2022	21	0.000%	0.0001
4000462570	142942	8,911	4/4/2022	4/25/2022	21	0.002%	0.0005
4000462674	8392	67,751	4/7/2022	4/28/2022	21	0.018%	0.0038
4000462686	125016	1,793	4/7/2022	4/28/2022	21	0.000%	0.0001
4000462859	34173	29,032	4/13/2022	5/4/2022	21	0.008%	0.0016
4000462861	34616	7,775	4/13/2022	5/4/2022	21	0.002%	0.0004
4000462840	144045	5,000	4/13/2022	5/4/2022	21	0.001%	0.0003
4000462957	28084	1,235	4/18/2022	5/9/2022	21	0.000%	0.0001
4000462935	10439	1,320	4/18/2022	5/9/2022	21	0.000%	0.0001
4000463255	106699	4,168	4/27/2022	5/18/2022	21	0.001%	0.0002
4000463439	34173	28,670	5/2/2022	5/23/2022	21	0.008%	0.0016
4000463483	142942	7,605	5/3/2022	5/24/2022	21	0.002%	0.0004
4000463575	34616	1,505	5/5/2022	5/26/2022	21	0.000%	0.0001
4000463567	144344	4,000	5/5/2022	5/26/2022	21	0.001%	0.0002
4000463713	11427	3,850	5/11/2022	6/1/2022	21	0.001%	0.0002
4000463717	25437	7,089	5/11/2022	6/1/2022	21	0.002%	0.0004
4000463719	25905	18,650	5/11/2022	6/1/2022	21	0.005%	0.0010
4000463704	144422	19,879	5/11/2022	6/1/2022	21	0.005%	0.0011
4000463705	144581	1,812	5/11/2022	6/1/2022	21	0.000%	0.0001
4000463848	123716	5,000	5/16/2022	6/6/2022	21	0.001%	0.0003
4000464016	24114	605	5/20/2022	6/10/2022	21	0.000%	0.0000
4000464078	129917	7,725	5/23/2022	6/13/2022	21	0.002%	0.0004
4000464122	26644	3,780	5/24/2022	6/14/2022	21	0.001%	0.0002
4000464109	144794	12,800	5/24/2022	6/14/2022	21	0.003%	0.0007
4000464147	138131	1,000	5/25/2022	6/15/2022	21	0.000%	0.0001
4000464189	133190	3,513	5/26/2022	6/16/2022	21	0.001%	0.0002
4000464310	137825	517	5/27/2022	6/17/2022	21	0.000%	0.0000
4000464372	4765	39,309	6/1/2022	6/22/2022	21	0.010%	0.0022
4000464483	34616	16,071	6/2/2022	6/23/2022	21	0.004%	0.0009
4000464551	142942	4,585	6/6/2022	6/27/2022	21	0.001%	0.0003
4000464684	9145	2,550	6/10/2022	7/1/2022	21	0.001%	0.0001
4000464807	11427	5,850	6/14/2022	7/5/2022	21	0.002%	0.0003
4000464794	116902	14,400	6/14/2022	7/5/2022	21	0.004%	0.0008
4000464798	139275	603	6/14/2022	7/5/2022	21	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464841	145180	5,000	6/15/2022	7/6/2022	21	0.001%	0.0003
4000464935	8392	10,408	6/17/2022	7/8/2022	21	0.003%	0.0006
4000465040	26299	1,559	6/22/2022	7/13/2022	21	0.000%	0.0001
4000465045	28619	8,674	6/22/2022	7/13/2022	21	0.002%	0.0005
4000465056	137825	225	6/22/2022	7/13/2022	21	0.000%	0.0000
4000465090	24885	350	6/23/2022	7/14/2022	21	0.000%	0.0000
4000465196	144668	776	6/27/2022	7/18/2022	21	0.000%	0.0000
4000465265	26644	2,160	6/28/2022	7/19/2022	21	0.001%	0.0001
4000465270	34616	14,093	6/28/2022	7/19/2022	21	0.004%	0.0008
4000465247	139089	500	6/28/2022	7/19/2022	21	0.000%	0.0000
4000465287	145210	1,000	6/29/2022	7/20/2022	21	0.000%	0.0001
4000465489	30252	9,576	7/5/2022	7/26/2022	21	0.003%	0.0005
4000465516	142942	3,386	7/6/2022	7/27/2022	21	0.001%	0.0002
4000465650	14463	33,967	7/11/2022	8/1/2022	21	0.009%	0.0019
4000465712	100910	500	7/12/2022	8/2/2022	21	0.000%	0.0000
4000465719	139631	153,816	7/12/2022	8/2/2022	21	0.041%	0.0085
4000465845	23681	1,592	7/15/2022	8/5/2022	21	0.000%	0.0001
4000465882	24251	11,160	7/18/2022	8/8/2022	21	0.003%	0.0006
4000465883	24251	11,580	7/18/2022	8/8/2022	21	0.003%	0.0006
4000465915	125016	2,420	7/19/2022	8/9/2022	21	0.001%	0.0001
4000465984	134054	17,475	7/21/2022	8/11/2022	21	0.005%	0.0010
4000466066	26588	12,140	7/22/2022	8/12/2022	21	0.003%	0.0007
4000466099	24885	3,400	7/25/2022	8/15/2022	21	0.001%	0.0002
4000466176	142942	1,540	7/27/2022	8/17/2022	21	0.000%	0.0001
4000466220	139275	268	7/28/2022	8/18/2022	21	0.000%	0.0000
4000466326	32245	1,736	7/29/2022	8/19/2022	21	0.000%	0.0001
4000466589	143785	52,660	8/8/2022	8/29/2022	21	0.014%	0.0029
4000466661	131089	2,500	8/10/2022	8/31/2022	21	0.001%	0.0001
4000466668	142681	235,118	8/10/2022	8/31/2022	21	0.062%	0.0130
4000466673	144372	250	8/10/2022	8/31/2022	21	0.000%	0.0000
4000466748	10384	16,550	8/11/2022	9/1/2022	21	0.004%	0.0009
4000466754	24211	6,624	8/11/2022	9/1/2022	21	0.002%	0.0004
4000466755	24259	1,349	8/11/2022	9/1/2022	21	0.000%	0.0001
4000466887	11631	13,000	8/16/2022	9/6/2022	21	0.003%	0.0007
4000467020	26643	2,135	8/19/2022	9/9/2022	21	0.001%	0.0001
4000467103	24191	5,290	8/23/2022	9/13/2022	21	0.001%	0.0003
4000467110	10137	500	8/24/2022	9/14/2022	21	0.000%	0.0000
4000467113	100448	2,500	8/24/2022	9/14/2022	21	0.001%	0.0001
4000467292	103603	2,218	8/30/2022	9/20/2022	21	0.001%	0.0001
4000467431	26382	3,769	9/1/2022	9/22/2022	21	0.001%	0.0002
4000467472	137912	4,052	9/2/2022	9/23/2022	21	0.001%	0.0002
4000467498	144344	13,600	9/2/2022	9/23/2022	21	0.004%	0.0008
4000467550	142942	10,296	9/6/2022	9/27/2022	21	0.003%	0.0006
4000467940	26301	2,322	9/20/2022	10/11/2022	21	0.001%	0.0001
4000467963	141754	23,000	9/21/2022	10/12/2022	21	0.006%	0.0013
4000468092	105195	19,866	9/23/2022	10/14/2022	21	0.005%	0.0011
4000468037	105195	2,639	9/23/2022	10/14/2022	21	0.001%	0.0001
4000468038	105752	10,000	9/23/2022	10/14/2022	21	0.003%	0.0006
4000468117	11054	8,370	9/26/2022	10/17/2022	21	0.002%	0.0005
4000468174	33058	293	9/27/2022	10/18/2022	21	0.000%	0.0000
4000468180	33097	48,676	9/27/2022	10/18/2022	21	0.013%	0.0027
4000468230	142942	3,059	9/28/2022	10/19/2022	21	0.001%	0.0002
4000468413	32897	700	9/30/2022	10/21/2022	21	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468607	34616	28,761	10/7/2022	10/28/2022	21	0.008%	0.0016
4000468608	34616	29,953	10/7/2022	10/28/2022	21	0.008%	0.0017
4000468559	124142	118,645	10/7/2022	10/28/2022	21	0.031%	0.0066
4000468571	144422	45,750	10/7/2022	10/28/2022	21	0.012%	0.0025
4000468720	145412	14,900	10/12/2022	11/2/2022	21	0.004%	0.0008
4000468777	28619	39,296	10/13/2022	11/3/2022	21	0.010%	0.0022
4000468831	30252	9,120	10/14/2022	11/4/2022	21	0.002%	0.0005
4000468865	139275	389	10/17/2022	11/7/2022	21	0.000%	0.0000
4000468912	132719	1,233,445	10/18/2022	11/8/2022	21	0.325%	0.0683
4000469299	24259	3,469	10/27/2022	11/17/2022	21	0.001%	0.0002
4000469317	34173	414	10/27/2022	11/17/2022	21	0.000%	0.0000
4000469318	34616	16,566	10/27/2022	11/17/2022	21	0.004%	0.0009
4000469385	28619	47,376	10/28/2022	11/18/2022	21	0.012%	0.0026
4000469399	134485	2,940	10/28/2022	11/18/2022	21	0.001%	0.0002
4000469332	30580	5,092	10/28/2022	11/18/2022	21	0.001%	0.0003
4000469359	143994	95,262	10/28/2022	11/18/2022	21	0.025%	0.0053
4000469437	24885	700	10/31/2022	11/21/2022	21	0.000%	0.0000
4000469497	126715	10,500	11/2/2022	11/23/2022	21	0.003%	0.0006
4000469603	6031	2,274	11/4/2022	11/25/2022	21	0.001%	0.0001
4000469768	34616	2,925	11/9/2022	11/30/2022	21	0.001%	0.0002
4000469928	26323	4,031	11/16/2022	12/7/2022	21	0.001%	0.0002
4000469913	141754	23,000	11/16/2022	12/7/2022	21	0.006%	0.0013
4000469986	28619	21,904	11/17/2022	12/8/2022	21	0.006%	0.0012
4000470052	137825	1,439	11/18/2022	12/9/2022	21	0.000%	0.0001
4000470096	26644	7,560	11/21/2022	12/12/2022	21	0.002%	0.0004
4000470120	142942	11,295	11/22/2022	12/13/2022	21	0.003%	0.0006
4000470229	137825	370	11/23/2022	12/14/2022	21	0.000%	0.0000
4000470167	139089	448	11/23/2022	12/14/2022	21	0.000%	0.0000
4000470262	26453	1,200	11/28/2022	12/19/2022	21	0.000%	0.0001
4000470279	137825	678	11/28/2022	12/19/2022	21	0.000%	0.0000
4000470345	11304	14,250	11/30/2022	12/21/2022	21	0.004%	0.0008
4000470390	107932	200	12/1/2022	12/22/2022	21	0.000%	0.0000
4000470391	107932	265	12/1/2022	12/22/2022	21	0.000%	0.0000
4000470455	32138	8,630	12/2/2022	12/23/2022	21	0.002%	0.0005
4000470686	34173	518	12/8/2022	12/29/2022	21	0.000%	0.0000
4000470719	145259	17,621	12/9/2022	12/30/2022	21	0.005%	0.0010
4000470844	18275	1,818	12/14/2022	1/4/2023	21	0.000%	0.0001
4000470869	130375	47,519	12/14/2022	1/4/2023	21	0.013%	0.0026
4000470815	103471	922	12/14/2022	1/4/2023	21	0.000%	0.0001
4000470827	132321	104	12/14/2022	1/4/2023	21	0.000%	0.0000
4000470917	135537	26,125	12/15/2022	1/5/2023	21	0.007%	0.0014
4000470918	33128	942	12/15/2022	1/5/2023	21	0.000%	0.0001
4000470925	33624	606	12/16/2022	1/6/2023	21	0.000%	0.0000
4000470927	104872	984	12/16/2022	1/6/2023	21	0.000%	0.0001
4000471100	30124	1,610	12/20/2022	1/10/2023	21	0.000%	0.0001
4000471074	144422	2,970	12/20/2022	1/10/2023	21	0.001%	0.0002
4000471169	34616	9,020	12/21/2022	1/11/2023	21	0.002%	0.0005
4000471252	26382	2,950	12/23/2022	1/13/2023	21	0.001%	0.0002
4000471267	135537	42,213	12/23/2022	1/13/2023	21	0.011%	0.0023
4000471412	125016	8,649	12/29/2022	1/19/2023	21	0.002%	0.0005
4000471426	30580	1,979	12/30/2022	1/20/2023	21	0.001%	0.0001
4000459643	11304	2,400	1/6/2022	1/28/2022	22	0.001%	0.0001
4000459645	20063	5,829	1/6/2022	1/28/2022	22	0.002%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000459706	142942	1,264	1/10/2022	2/1/2022	22	0.000%	0.0001
4000459786	144479	476,382	1/12/2022	2/3/2022	22	0.126%	0.0276
4000459810	129552	6,000	1/13/2022	2/4/2022	22	0.002%	0.0003
4000460034	23681	4,245	1/19/2022	2/10/2022	22	0.001%	0.0002
4000460159	26493	11,086	1/24/2022	2/15/2022	22	0.003%	0.0006
4000460143	141203	38,165	1/24/2022	2/15/2022	22	0.010%	0.0022
4000460146	143189	72,205	1/24/2022	2/15/2022	22	0.019%	0.0042
4000460590	24251	3,480	1/31/2022	2/22/2022	22	0.001%	0.0002
4000460652	142942	3,230	2/1/2022	2/23/2022	22	0.001%	0.0002
4000460747	26381	2,880	2/3/2022	2/25/2022	22	0.001%	0.0002
4000460853	25266	4,428	2/8/2022	3/2/2022	22	0.001%	0.0003
4000460904	23681	12,310	2/9/2022	3/3/2022	22	0.003%	0.0007
4000460885	10439	11,220	2/9/2022	3/3/2022	22	0.003%	0.0007
4000461179	142942	4,281	2/17/2022	3/11/2022	22	0.001%	0.0002
4000461276	123377	3,519	2/22/2022	3/16/2022	22	0.001%	0.0002
4000461471	30580	2,484	2/28/2022	3/22/2022	22	0.001%	0.0001
4000461557	137912	3,859	3/2/2022	3/24/2022	22	0.001%	0.0002
4000461538	116138	1,500	3/2/2022	3/24/2022	22	0.000%	0.0001
4000461676	1101	2,750	3/7/2022	3/29/2022	22	0.001%	0.0002
4000461687	114669	390	3/7/2022	3/29/2022	22	0.000%	0.0000
4000461858	121289	1,500	3/14/2022	4/5/2022	22	0.000%	0.0001
4000461932	141754	23,000	3/16/2022	4/7/2022	22	0.006%	0.0013
4000462001	106699	1,575	3/17/2022	4/8/2022	22	0.000%	0.0001
4000462138	130375	3,706	3/22/2022	4/13/2022	22	0.001%	0.0002
4000462282	142269	5,000	3/29/2022	4/20/2022	22	0.001%	0.0003
4000462463	34616	1,656	3/31/2022	4/22/2022	22	0.000%	0.0001
4000462836	142087	1,000	4/13/2022	5/5/2022	22	0.000%	0.0001
4000462944	141754	23,000	4/18/2022	5/10/2022	22	0.006%	0.0013
4000462966	27230	12,575	4/19/2022	5/11/2022	22	0.003%	0.0007
4000463145	14773	2,000	4/25/2022	5/17/2022	22	0.001%	0.0001
4000463202	106699	4,753	4/26/2022	5/18/2022	22	0.001%	0.0003
4000463422	142942	10,533	5/2/2022	5/24/2022	22	0.003%	0.0006
4000463509	26301	6,891	5/3/2022	5/25/2022	22	0.002%	0.0004
4000463513	28619	3,396	5/3/2022	5/25/2022	22	0.001%	0.0002
4000463529	144344	5,000	5/4/2022	5/26/2022	22	0.001%	0.0003
4000463641	27512	993	5/9/2022	5/31/2022	22	0.000%	0.0001
4000463635	145124	3,846	5/9/2022	5/31/2022	22	0.001%	0.0002
4000463671	26301	4,794	5/10/2022	6/1/2022	22	0.001%	0.0003
4000463875	145094	1,000	5/16/2022	6/7/2022	22	0.000%	0.0001
4000464131	34173	18,475	5/24/2022	6/15/2022	22	0.005%	0.0011
4000464237	137825	993	5/26/2022	6/17/2022	22	0.000%	0.0001
4000464338	144974	12,757	5/31/2022	6/22/2022	22	0.003%	0.0007
4000464400	25029	3,484	6/1/2022	6/23/2022	22	0.001%	0.0002
4000464434	137912	1,415	6/2/2022	6/24/2022	22	0.000%	0.0001
4000464450	143272	1,000	6/2/2022	6/24/2022	22	0.000%	0.0001
4000464745	109293	3,200	6/13/2022	7/5/2022	22	0.001%	0.0002
4000465280	139275	205	6/29/2022	7/21/2022	22	0.000%	0.0000
4000465488	28619	10,659	7/5/2022	7/27/2022	22	0.003%	0.0006
4000465478	142942	7,531	7/5/2022	7/27/2022	22	0.002%	0.0004
4000465514	138366	13,500	7/6/2022	7/28/2022	22	0.004%	0.0008
4000465553	24885	2,800	7/7/2022	7/29/2022	22	0.001%	0.0002
4000465648	8998	30,214	7/11/2022	8/2/2022	22	0.008%	0.0018
4000465632	29254	1,937	7/11/2022	8/2/2022	22	0.001%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465662	32946	6,326	7/11/2022	8/2/2022	22	0.002%	0.0004
4000465664	32950	49,627	7/11/2022	8/2/2022	22	0.013%	0.0029
4000465671	32970	69,565	7/11/2022	8/2/2022	22	0.018%	0.0040
4000465673	32978	1,397	7/11/2022	8/2/2022	22	0.000%	0.0001
4000465677	32994	854	7/11/2022	8/2/2022	22	0.000%	0.0000
4000465678	33001	95,436	7/11/2022	8/2/2022	22	0.025%	0.0055
4000465680	33014	33,191	7/11/2022	8/2/2022	22	0.009%	0.0019
4000465681	33026	794	7/11/2022	8/2/2022	22	0.000%	0.0000
4000465684	33039	4,962	7/11/2022	8/2/2022	22	0.001%	0.0003
4000465686	33041	21,258	7/11/2022	8/2/2022	22	0.006%	0.0012
4000465690	33075	46,158	7/11/2022	8/2/2022	22	0.012%	0.0027
4000465696	33097	4,837	7/11/2022	8/2/2022	22	0.001%	0.0003
4000465697	33098	38,452	7/11/2022	8/2/2022	22	0.010%	0.0022
4000465706	33131	42,643	7/11/2022	8/2/2022	22	0.011%	0.0025
4000465729	25029	2,496	7/12/2022	8/3/2022	22	0.001%	0.0001
4000465982	135537	34,025	7/20/2022	8/11/2022	22	0.009%	0.0020
4000466129	142942	5,692	7/26/2022	8/17/2022	22	0.002%	0.0003
4000466141	144344	5,000	7/26/2022	8/17/2022	22	0.001%	0.0003
4000466514	26363	743	8/4/2022	8/26/2022	22	0.000%	0.0000
4000467087	116138	2,100	8/23/2022	9/14/2022	22	0.001%	0.0001
4000467139	25029	2,184	8/24/2022	9/15/2022	22	0.001%	0.0001
4000467376	26016	3,876	8/31/2022	9/22/2022	22	0.001%	0.0002
4000467815	24885	350	9/15/2022	10/7/2022	22	0.000%	0.0000
4000467913	125016	8,605	9/19/2022	10/11/2022	22	0.002%	0.0005
4000467918	105195	16,925	9/20/2022	10/12/2022	22	0.004%	0.0010
4000468008	8998	24,855	9/22/2022	10/14/2022	22	0.007%	0.0014
4000468142	142942	6,960	9/27/2022	10/19/2022	22	0.002%	0.0004
4000468213	111671	1,500	9/28/2022	10/20/2022	22	0.000%	0.0001
4000468535	34616	11,411	10/6/2022	10/28/2022	22	0.003%	0.0007
4000468502	9145	1,200	10/6/2022	10/28/2022	22	0.000%	0.0001
4000468725	24885	300	10/12/2022	11/3/2022	22	0.000%	0.0000
4000468886	27162	18,956	10/17/2022	11/8/2022	22	0.005%	0.0011
4000468861	123383	35,963	10/17/2022	11/8/2022	22	0.009%	0.0021
4000469139	108762	15,000	10/24/2022	11/15/2022	22	0.004%	0.0009
4000469206	128433	500	10/26/2022	11/17/2022	22	0.000%	0.0000
4000469589	28619	1,456	11/3/2022	11/25/2022	22	0.000%	0.0001
4000469598	125016	1,031	11/3/2022	11/25/2022	22	0.000%	0.0001
4000469685	28084	2,090	11/7/2022	11/29/2022	22	0.001%	0.0001
4000469751	25029	20,020	11/9/2022	12/1/2022	22	0.005%	0.0012
4000469833	137825	9	11/10/2022	12/2/2022	22	0.000%	0.0000
4000469789	126928	84	11/10/2022	12/2/2022	22	0.000%	0.0000
4000469906	103603	2,195	11/16/2022	12/8/2022	22	0.001%	0.0001
4000469915	142269	5,000	11/16/2022	12/8/2022	22	0.001%	0.0003
4000470100	103952	5,000	11/22/2022	12/14/2022	22	0.001%	0.0003
4000470190	145208	8,500	11/23/2022	12/15/2022	22	0.002%	0.0005
4000470237	123915	4,085	11/28/2022	12/20/2022	22	0.001%	0.0002
4000470294	116971	3,000	11/29/2022	12/21/2022	22	0.001%	0.0002
4000470295	116971	3,000	11/29/2022	12/21/2022	22	0.001%	0.0002
4000470359	26301	3,745	11/30/2022	12/22/2022	22	0.001%	0.0002
4000470387	125360	72,495	11/30/2022	12/22/2022	22	0.019%	0.0042
4000470433	14463	51,185	12/1/2022	12/23/2022	22	0.014%	0.0030
4000470567	11427	800	12/5/2022	12/27/2022	22	0.000%	0.0000
4000470587	13911	580	12/6/2022	12/28/2022	22	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470589	24885	600	12/6/2022	12/28/2022	22	0.000%	0.0000
4000470665	144530	53,722	12/8/2022	12/30/2022	22	0.014%	0.0031
4000470871	135537	35,250	12/14/2022	1/5/2023	22	0.009%	0.0020
4000471104	34616	9,816	12/20/2022	1/11/2023	22	0.003%	0.0006
4000471075	144924	1,500	12/20/2022	1/11/2023	22	0.000%	0.0001
4000471159	26643	2,718	12/21/2022	1/12/2023	22	0.001%	0.0002
4000471164	27013	7,668	12/21/2022	1/12/2023	22	0.002%	0.0004
4000471206	26381	1,600	12/22/2022	1/13/2023	22	0.000%	0.0001
4000459564	135537	12,456	1/3/2022	1/26/2022	23	0.003%	0.0008
4000459565	103278	750	1/4/2022	1/27/2022	23	0.000%	0.0000
4000459566	103278	750	1/4/2022	1/27/2022	23	0.000%	0.0000
4000459567	103278	750	1/4/2022	1/27/2022	23	0.000%	0.0000
4000459568	103278	750	1/4/2022	1/27/2022	23	0.000%	0.0000
4000459569	103278	750	1/4/2022	1/27/2022	23	0.000%	0.0000
4000459757	23681	11,992	1/11/2022	2/3/2022	23	0.003%	0.0007
4000459990	23681	6,155	1/18/2022	2/10/2022	23	0.002%	0.0004
4000460244	143216	141,693	1/25/2022	2/17/2022	23	0.037%	0.0086
4000460226	133368	7,500	1/25/2022	2/17/2022	23	0.002%	0.0005
4000460567	35151	4,500	1/31/2022	2/23/2022	23	0.001%	0.0003
4000460577	142942	3,242	1/31/2022	2/23/2022	23	0.001%	0.0002
4000460618	107932	2,500	2/1/2022	2/24/2022	23	0.001%	0.0002
4000460829	11427	19,500	2/7/2022	3/2/2022	23	0.005%	0.0012
4000461077	107932	75,000	2/15/2022	3/10/2022	23	0.020%	0.0045
4000461079	144893	1,800	2/15/2022	3/10/2022	23	0.000%	0.0001
4000461143	8998	53,958	2/16/2022	3/11/2022	23	0.014%	0.0033
4000461135	142942	2,948	2/16/2022	3/11/2022	23	0.001%	0.0002
4000461468	107932	100	2/28/2022	3/23/2022	23	0.000%	0.0000
4000461745	134480	110	3/9/2022	4/1/2022	23	0.000%	0.0000
4000461945	23681	9,339	3/16/2022	4/8/2022	23	0.002%	0.0006
4000462064	112527	5,000	3/21/2022	4/13/2022	23	0.001%	0.0003
4000462401	34616	9,318	3/30/2022	4/22/2022	23	0.002%	0.0006
4000462777	34616	3,011	4/11/2022	5/4/2022	23	0.001%	0.0002
4000462843	144669	2,500	4/13/2022	5/6/2022	23	0.001%	0.0002
4000462847	145026	500	4/13/2022	5/6/2022	23	0.000%	0.0000
4000463490	144031	1,403	5/3/2022	5/26/2022	23	0.000%	0.0001
4000463882	14463	28,855	5/16/2022	6/8/2022	23	0.008%	0.0018
4000463914	141754	23,000	5/17/2022	6/9/2022	23	0.006%	0.0014
4000464347	25029	4,056	5/31/2022	6/23/2022	23	0.001%	0.0002
4000464353	26301	1,348	5/31/2022	6/23/2022	23	0.000%	0.0001
4000464312	10439	1,760	5/31/2022	6/23/2022	23	0.000%	0.0001
4000464797	134967	1,000	6/14/2022	7/7/2022	23	0.000%	0.0001
4000464992	26299	2,331	6/20/2022	7/13/2022	23	0.001%	0.0001
4000465184	111985	20,000	6/27/2022	7/20/2022	23	0.005%	0.0012
4000465709	33078	4,729	7/11/2022	8/3/2022	23	0.001%	0.0003
4000465663	32948	3,907	7/11/2022	8/3/2022	23	0.001%	0.0002
4000465665	32952	31,676	7/11/2022	8/3/2022	23	0.008%	0.0019
4000465666	32957	1,705	7/11/2022	8/3/2022	23	0.000%	0.0001
4000465667	32961	41,767	7/11/2022	8/3/2022	23	0.011%	0.0025
4000465668	32965	5,089	7/11/2022	8/3/2022	23	0.001%	0.0003
4000465670	32968	8,653	7/11/2022	8/3/2022	23	0.002%	0.0005
4000465672	32976	2,879	7/11/2022	8/3/2022	23	0.001%	0.0002
4000465674	32981	25,680	7/11/2022	8/3/2022	23	0.007%	0.0016
4000465679	33010	18,044	7/11/2022	8/3/2022	23	0.005%	0.0011

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000465682	33030	107,607	7/11/2022	8/3/2022	23	0.028%	0.0065
4000465683	33034	1,416	7/11/2022	8/3/2022	23	0.000%	0.0001
4000465685	33040	348	7/11/2022	8/3/2022	23	0.000%	0.0000
4000465688	33070	14,076	7/11/2022	8/3/2022	23	0.004%	0.0009
4000465689	33073	2,470	7/11/2022	8/3/2022	23	0.001%	0.0001
4000465691	33077	14,493	7/11/2022	8/3/2022	23	0.004%	0.0009
4000465694	33084	1,381	7/11/2022	8/3/2022	23	0.000%	0.0001
4000465698	33103	5,471	7/11/2022	8/3/2022	23	0.001%	0.0003
4000465699	33114	132,016	7/11/2022	8/3/2022	23	0.035%	0.0080
4000465700	33115	1,627	7/11/2022	8/3/2022	23	0.000%	0.0001
4000465701	33116	3,587	7/11/2022	8/3/2022	23	0.001%	0.0002
4000465703	33120	59,037	7/11/2022	8/3/2022	23	0.016%	0.0036
4000465704	33122	21,975	7/11/2022	8/3/2022	23	0.006%	0.0013
4000465705	33125	2,995	7/11/2022	8/3/2022	23	0.001%	0.0002
4000465707	33139	30,241	7/11/2022	8/3/2022	23	0.008%	0.0018
4000465708	33141	8,325	7/11/2022	8/3/2022	23	0.002%	0.0005
4000465731	34616	19,635	7/12/2022	8/4/2022	23	0.005%	0.0012
4000465929	33045	31,341	7/19/2022	8/11/2022	23	0.008%	0.0019
4000466103	26299	1,488	7/25/2022	8/17/2022	23	0.000%	0.0001
4000466094	142942	7,753	7/25/2022	8/17/2022	23	0.002%	0.0005
4000466117	134906	3,900	7/26/2022	8/18/2022	23	0.001%	0.0002
4000466439	116902	1,750	8/3/2022	8/26/2022	23	0.000%	0.0001
4000466591	8998	39,836	8/8/2022	8/31/2022	23	0.011%	0.0024
4000466597	24885	350	8/8/2022	8/31/2022	23	0.000%	0.0000
4000466667	142636	1,000	8/10/2022	9/2/2022	23	0.000%	0.0001
4000466823	9891	650	8/15/2022	9/7/2022	23	0.000%	0.0000
4000467086	34173	12,938	8/22/2022	9/14/2022	23	0.003%	0.0008
4000467102	14463	20,369	8/23/2022	9/15/2022	23	0.005%	0.0012
4000467105	25029	2,860	8/23/2022	9/15/2022	23	0.001%	0.0002
4000467753	24885	700	9/14/2022	10/7/2022	23	0.000%	0.0000
4000468109	142942	5,187	9/26/2022	10/19/2022	23	0.001%	0.0003
4000468497	34616	10,794	10/5/2022	10/28/2022	23	0.003%	0.0007
4000469195	24292	521	10/25/2022	11/17/2022	23	0.000%	0.0000
4000469422	142269	7,500	10/31/2022	11/23/2022	23	0.002%	0.0005
4000469498	131647	2,525	11/2/2022	11/25/2022	23	0.001%	0.0002
4000469528	145152	8,240	11/2/2022	11/25/2022	23	0.002%	0.0005
4000469680	8998	40,662	11/7/2022	11/30/2022	23	0.011%	0.0025
4000469687	34616	24,611	11/7/2022	11/30/2022	23	0.006%	0.0015
4000470065	128338	7,500	11/21/2022	12/14/2022	23	0.002%	0.0005
4000470068	133648	1,500	11/21/2022	12/14/2022	23	0.000%	0.0001
4000470053	107932	330	11/21/2022	12/14/2022	23	0.000%	0.0000
4000470248	116971	3,000	11/28/2022	12/21/2022	23	0.001%	0.0002
4000470553	133768	5,053	12/5/2022	12/28/2022	23	0.001%	0.0003
4000470596	34173	5,826	12/6/2022	12/29/2022	23	0.002%	0.0004
4000470625	144720	122,815	12/7/2022	12/30/2022	23	0.032%	0.0075
4000470808	135537	22,375	12/13/2022	1/5/2023	23	0.006%	0.0014
4000470868	123383	4,725	12/14/2022	1/6/2023	23	0.001%	0.0003
4000471052	34616	1,058	12/19/2022	1/11/2023	23	0.000%	0.0001
4000471084	11304	12,225	12/20/2022	1/12/2023	23	0.003%	0.0007
4000471087	25029	9,568	12/20/2022	1/12/2023	23	0.003%	0.0006
4000471094	27013	10,696	12/20/2022	1/12/2023	23	0.003%	0.0006
4000471155	26382	492	12/21/2022	1/13/2023	23	0.000%	0.0000
4000471160	26644	17,348	12/21/2022	1/13/2023	23	0.005%	0.0011

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471338	135537	17,125	12/28/2022	1/20/2023	23	0.005%	0.0010
4000459674	11427	2,650	1/7/2022	1/31/2022	24	0.001%	0.0002
4000459680	24885	700	1/7/2022	1/31/2022	24	0.000%	0.0000
4000459908	32922	1,014	1/14/2022	2/7/2022	24	0.000%	0.0001
4000460102	26299	500	1/21/2022	2/14/2022	24	0.000%	0.0000
4000460141	139128	709	1/24/2022	2/17/2022	24	0.000%	0.0000
4000460664	8998	19,951	2/1/2022	2/25/2022	24	0.005%	0.0013
4000460634	137912	3,859	2/1/2022	2/25/2022	24	0.001%	0.0002
4000460783	144422	51,640	2/4/2022	2/28/2022	24	0.014%	0.0033
4000460860	124751	1,437	2/8/2022	3/4/2022	24	0.000%	0.0001
4000460876	144922	6,000	2/8/2022	3/4/2022	24	0.002%	0.0004
4000461073	28619	5,643	2/14/2022	3/10/2022	24	0.001%	0.0004
4000461091	142942	3,713	2/15/2022	3/11/2022	24	0.001%	0.0002
4000461253	30068	358	2/18/2022	3/14/2022	24	0.000%	0.0000
4000461235	142587	310	2/18/2022	3/14/2022	24	0.000%	0.0000
4000461444	23681	5,837	2/25/2022	3/21/2022	24	0.002%	0.0004
4000461457	28619	21,379	2/25/2022	3/21/2022	24	0.006%	0.0014
4000461659	25029	1,352	3/4/2022	3/28/2022	24	0.000%	0.0001
4000462040	25029	1,768	3/18/2022	4/11/2022	24	0.000%	0.0001
4000462067	122574	100	3/21/2022	4/14/2022	24	0.000%	0.0000
4000462314	34616	6,781	3/29/2022	4/22/2022	24	0.002%	0.0004
4000462504	142942	18,062	4/1/2022	4/25/2022	24	0.005%	0.0011
4000462569	142874	14,820	4/4/2022	4/28/2022	24	0.004%	0.0009
4000463124	28619	13,188	4/22/2022	5/16/2022	24	0.003%	0.0008
4000463427	25029	11,492	5/2/2022	5/26/2022	24	0.003%	0.0007
4000463463	126715	3,548	5/3/2022	5/27/2022	24	0.001%	0.0002
4000464094	30557	7,174	5/23/2022	6/16/2022	24	0.002%	0.0005
4000464339	145120	32,000	5/31/2022	6/24/2022	24	0.008%	0.0020
4000464510	142942	23,193	6/3/2022	6/27/2022	24	0.006%	0.0015
4000464973	125016	2,868	6/17/2022	7/11/2022	24	0.001%	0.0002
4000464919	139275	268	6/17/2022	7/11/2022	24	0.000%	0.0000
4000465242	116902	19,388	6/28/2022	7/22/2022	24	0.005%	0.0012
4000465243	116902	23,230	6/28/2022	7/22/2022	24	0.006%	0.0015
4000465423	145028	15,000	7/1/2022	7/25/2022	24	0.004%	0.0009
4000465661	32928	82,162	7/11/2022	8/4/2022	24	0.022%	0.0052
4000465669	32967	9,149	7/11/2022	8/4/2022	24	0.002%	0.0006
4000465675	32983	44,912	7/11/2022	8/4/2022	24	0.012%	0.0028
4000465676	32990	5,242	7/11/2022	8/4/2022	24	0.001%	0.0003
4000465695	33095	738	7/11/2022	8/4/2022	24	0.000%	0.0000
4000465830	143137	1,272	7/15/2022	8/8/2022	24	0.000%	0.0001
4000466023	10439	1,045	7/22/2022	8/15/2022	24	0.000%	0.0001
4000466085	103265	24,381	7/25/2022	8/18/2022	24	0.006%	0.0015
4000466307	26643	3,086	7/29/2022	8/22/2022	24	0.001%	0.0002
4000466270	108289	284	7/29/2022	8/22/2022	24	0.000%	0.0000
4000466375	25029	10,244	8/1/2022	8/25/2022	24	0.003%	0.0006
4000466565	23681	2,971	8/5/2022	8/29/2022	24	0.001%	0.0002
4000466549	143189	34,858	8/5/2022	8/29/2022	24	0.009%	0.0022
4000466584	123383	6,550	8/8/2022	9/1/2022	24	0.002%	0.0004
4000467012	11536	2,258	8/19/2022	9/12/2022	24	0.001%	0.0001
4000467536	125016	1,524	9/2/2022	9/26/2022	24	0.000%	0.0001
4000467492	143436	836	9/2/2022	9/26/2022	24	0.000%	0.0001
4000468073	25029	1,040	9/23/2022	10/17/2022	24	0.000%	0.0001
4000468164	135537	28,198	9/27/2022	10/21/2022	24	0.007%	0.0018

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468177	33080	124,296	9/27/2022	10/21/2022	24	0.033%	0.0079
4000468404	24885	700	9/30/2022	10/24/2022	24	0.000%	0.0000
4000468425	125016	2,330	9/30/2022	10/24/2022	24	0.001%	0.0001
4000468341	131647	2,525	9/30/2022	10/24/2022	24	0.001%	0.0002
4000468347	141021	2,700	9/30/2022	10/24/2022	24	0.001%	0.0002
4000468387	144996	2,500	9/30/2022	10/24/2022	24	0.001%	0.0002
4000468439	145028	15,000	10/3/2022	10/27/2022	24	0.004%	0.0009
4000468541	17293	6,000	10/7/2022	10/31/2022	24	0.002%	0.0004
4000468561	142942	12,397	10/7/2022	10/31/2022	24	0.003%	0.0008
4000468667	34173	21,580	10/11/2022	11/4/2022	24	0.006%	0.0014
4000468849	11427	13,400	10/17/2022	11/10/2022	24	0.004%	0.0008
4000469075	6031	880	10/21/2022	11/14/2022	24	0.000%	0.0001
4000469133	128433	1,500	10/24/2022	11/17/2022	24	0.000%	0.0001
4000469134	128433	1,500	10/24/2022	11/17/2022	24	0.000%	0.0001
4000469200	26644	5,400	10/25/2022	11/18/2022	24	0.001%	0.0003
4000469373	24885	1,750	10/28/2022	11/21/2022	24	0.000%	0.0001
4000469400	135537	40,560	10/28/2022	11/21/2022	24	0.011%	0.0026
4000469668	126107	2,500	11/7/2022	12/1/2022	24	0.001%	0.0002
4000469696	143189	16,627	11/8/2022	12/2/2022	24	0.004%	0.0011
4000470266	26679	19,563	11/28/2022	12/22/2022	24	0.005%	0.0012
4000470275	34616	882	11/28/2022	12/22/2022	24	0.000%	0.0001
4000470303	26312	22,050	11/29/2022	12/23/2022	24	0.006%	0.0014
4000470570	34173	5,256	12/5/2022	12/29/2022	24	0.001%	0.0003
4000470750	126928	169	12/12/2022	1/5/2023	24	0.000%	0.0000
4000470752	139275	195	12/12/2022	1/5/2023	24	0.000%	0.0000
4000470792	144530	10,332	12/13/2022	1/6/2023	24	0.003%	0.0007
4000470783	108649	384	12/13/2022	1/6/2023	24	0.000%	0.0000
4000471018	33924	86,309	12/16/2022	1/9/2023	24	0.023%	0.0055
4000470981	144573	4,000	12/16/2022	1/9/2023	24	0.001%	0.0003
4000471049	26643	3,401	12/19/2022	1/12/2023	24	0.001%	0.0002
4000471091	26381	36,320	12/20/2022	1/13/2023	24	0.010%	0.0023
4000471484	20063	3,872	12/30/2022	1/23/2023	24	0.001%	0.0002
4000471518	34715	7,800	12/30/2022	1/23/2023	24	0.002%	0.0005
4000471452	143400	3,000	12/30/2022	1/23/2023	24	0.001%	0.0002
4000471470	145152	2,715	12/30/2022	1/23/2023	24	0.001%	0.0002
4000459669	142942	1,036	1/7/2022	2/1/2022	25	0.000%	0.0001
4000459730	26453	3,580	1/10/2022	2/4/2022	25	0.001%	0.0002
4000459851	144659	1,924,982	1/13/2022	2/7/2022	25	0.508%	0.1269
4000460083	23681	4,775	1/20/2022	2/14/2022	25	0.001%	0.0003
4000460090	28619	3,401	1/20/2022	2/14/2022	25	0.001%	0.0002
4000460480	28619	6,218	1/28/2022	2/22/2022	25	0.002%	0.0004
4000460454	101853	5,827	1/28/2022	2/22/2022	25	0.002%	0.0004
4000460538	33127	40,915	1/28/2022	2/22/2022	25	0.011%	0.0027
4000460766	30580	3,726	2/4/2022	3/1/2022	25	0.001%	0.0002
4000461035	26493	15	2/11/2022	3/8/2022	25	0.000%	0.0000
4000461056	142942	8,668	2/14/2022	3/11/2022	25	0.002%	0.0006
4000461046	115957	125	2/14/2022	3/11/2022	25	0.000%	0.0000
4000461047	115957	125	2/14/2022	3/11/2022	25	0.000%	0.0000
4000461188	23681	13,265	2/17/2022	3/14/2022	25	0.003%	0.0009
4000461485	127072	5,000	2/28/2022	3/25/2022	25	0.001%	0.0003
4000461622	144858	400	3/3/2022	3/28/2022	25	0.000%	0.0000
4000461652	144422	41,668	3/4/2022	3/29/2022	25	0.011%	0.0027
4000462027	143189	12,828	3/18/2022	4/12/2022	25	0.003%	0.0008

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462423	142942	1,932	3/31/2022	4/25/2022	25	0.001%	0.0001
4000462518	8998	840	4/1/2022	4/26/2022	25	0.000%	0.0001
4000462761	10384	6,850	4/11/2022	5/6/2022	25	0.002%	0.0005
4000463135	34616	16,267	4/22/2022	5/17/2022	25	0.004%	0.0011
4000463350	142942	20,449	4/29/2022	5/24/2022	25	0.005%	0.0013
4000463789	145100	5,943	5/13/2022	6/7/2022	25	0.002%	0.0004
4000463884	24114	4,070	5/16/2022	6/10/2022	25	0.001%	0.0003
4000464040	144794	15,100	5/20/2022	6/14/2022	25	0.004%	0.0010
4000464069	105376	2,600	5/23/2022	6/17/2022	25	0.001%	0.0002
4000464264	123383	12,280	5/27/2022	6/21/2022	25	0.003%	0.0008
4000464448	142942	514	6/2/2022	6/27/2022	25	0.000%	0.0000
4000464529	25644	3,296	6/3/2022	6/28/2022	25	0.001%	0.0002
4000464502	129383	3,345	6/3/2022	6/28/2022	25	0.001%	0.0002
4000464737	34616	9,954	6/10/2022	7/5/2022	25	0.003%	0.0007
4000464897	125016	717	6/16/2022	7/11/2022	25	0.000%	0.0000
4000464876	141754	23,000	6/16/2022	7/11/2022	25	0.006%	0.0015
4000464884	144881	16,893	6/16/2022	7/11/2022	25	0.004%	0.0011
4000464975	126165	3,674	6/17/2022	7/12/2022	25	0.001%	0.0002
4000465152	24191	2,443	6/24/2022	7/19/2022	25	0.001%	0.0002
4000465170	34616	12,012	6/24/2022	7/19/2022	25	0.003%	0.0008
4000465174	137825	410	6/24/2022	7/19/2022	25	0.000%	0.0000
4000465110	129754	4,243	6/24/2022	7/19/2022	25	0.001%	0.0003
4000465381	9673	5,675	7/1/2022	7/26/2022	25	0.001%	0.0004
4000465692	33079	20,143	7/11/2022	8/5/2022	25	0.005%	0.0013
4000465702	33119	5,965	7/11/2022	8/5/2022	25	0.002%	0.0004
4000465987	10439	550	7/21/2022	8/15/2022	25	0.000%	0.0000
4000466334	34616	29,914	7/29/2022	8/23/2022	25	0.008%	0.0020
4000466335	34616	26,974	7/29/2022	8/23/2022	25	0.007%	0.0018
4000466389	34616	9,780	8/1/2022	8/26/2022	25	0.003%	0.0006
4000466842	26301	7,939	8/15/2022	9/9/2022	25	0.002%	0.0005
4000467206	103603	2,195	8/26/2022	9/20/2022	25	0.001%	0.0001
4000467486	142942	28,623	9/2/2022	9/27/2022	25	0.008%	0.0019
4000467513	145323	30,000	9/2/2022	9/27/2022	25	0.008%	0.0020
4000467873	30124	2,530	9/16/2022	10/11/2022	25	0.001%	0.0002
4000468023	34616	7,577	9/22/2022	10/17/2022	25	0.002%	0.0005
4000468293	24211	2,879	9/29/2022	10/24/2022	25	0.001%	0.0002
4000468466	34616	12,156	10/3/2022	10/28/2022	25	0.003%	0.0008
4000468827	27162	7,896	10/14/2022	11/8/2022	25	0.002%	0.0005
4000469042	123915	1,430	10/20/2022	11/14/2022	25	0.000%	0.0001
4000469109	9891	9,725	10/21/2022	11/15/2022	25	0.003%	0.0006
4000469112	20063	3,751	10/21/2022	11/15/2022	25	0.001%	0.0002
4000469325	135537	7,375	10/27/2022	11/21/2022	25	0.002%	0.0005
4000469256	103278	77,817	10/27/2022	11/21/2022	25	0.021%	0.0051
4000469454	125016	4,571	10/31/2022	11/25/2022	25	0.001%	0.0003
4000469811	145208	1,160	11/10/2022	12/5/2022	25	0.000%	0.0001
4000469981	23681	4,245	11/17/2022	12/12/2022	25	0.001%	0.0003
4000469993	125016	22,721	11/17/2022	12/12/2022	25	0.006%	0.0015
4000470032	25029	11,440	11/18/2022	12/13/2022	25	0.003%	0.0008
4000470691	107932	790	12/9/2022	1/3/2023	25	0.000%	0.0001
4000470758	143941	180	12/12/2022	1/6/2023	25	0.000%	0.0000
4000470906	24251	480	12/15/2022	1/9/2023	25	0.000%	0.0000
4000470913	33924	170,375	12/15/2022	1/9/2023	25	0.045%	0.0112
4000470926	35112	86,135	12/16/2022	1/10/2023	25	0.023%	0.0057

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000471047	24885	4,925	12/19/2022	1/13/2023	25	0.001%	0.0003
4000471245	13911	53,720	12/23/2022	1/17/2023	25	0.014%	0.0035
4000471247	24211	5,555	12/23/2022	1/17/2023	25	0.001%	0.0004
4000471253	26453	960	12/23/2022	1/17/2023	25	0.000%	0.0001
4000471258	28619	35,632	12/23/2022	1/17/2023	25	0.009%	0.0023
4000471378	23681	531	12/29/2022	1/23/2023	25	0.000%	0.0000
4000471407	30475	60,812	12/29/2022	1/23/2023	25	0.016%	0.0040
4000471410	34616	6,799	12/29/2022	1/23/2023	25	0.002%	0.0004
4000471413	126165	46,211	12/29/2022	1/23/2023	25	0.012%	0.0030
4000459631	142942	5,225	1/6/2022	2/1/2022	26	0.001%	0.0004
4000459691	27068	6,464	1/7/2022	2/2/2022	26	0.002%	0.0004
4000459660	25266	8,982	1/7/2022	2/2/2022	26	0.002%	0.0006
4000459875	34616	4,934	1/13/2022	2/8/2022	26	0.001%	0.0003
4000459906	125016	5,916	1/14/2022	2/9/2022	26	0.002%	0.0004
4000459892	141754	23,000	1/14/2022	2/9/2022	26	0.006%	0.0016
4000460040	28619	4,807	1/19/2022	2/14/2022	26	0.001%	0.0003
4000460428	23681	3,714	1/27/2022	2/22/2022	26	0.001%	0.0003
4000460399	33127	40,915	1/27/2022	2/22/2022	26	0.011%	0.0028
4000460486	125016	4,123	1/28/2022	2/23/2022	26	0.001%	0.0003
4000460707	25644	14,469	2/2/2022	2/28/2022	26	0.004%	0.0010
4000460764	25266	926	2/4/2022	3/2/2022	26	0.000%	0.0001
4000460765	29254	10,330	2/4/2022	3/2/2022	26	0.003%	0.0007
4000461612	130375	2,000	3/3/2022	3/29/2022	26	0.001%	0.0001
4000462009	11427	3,450	3/18/2022	4/13/2022	26	0.001%	0.0002
4000462361	142942	1,033	3/30/2022	4/25/2022	26	0.000%	0.0001
4000462432	8998	15,851	3/31/2022	4/26/2022	26	0.004%	0.0011
4000462422	142269	6,000	3/31/2022	4/26/2022	26	0.002%	0.0004
4000462742	34616	7,156	4/8/2022	5/4/2022	26	0.002%	0.0005
4000462703	133926	4,312	4/8/2022	5/4/2022	26	0.001%	0.0003
4000462894	8998	48,477	4/14/2022	5/10/2022	26	0.013%	0.0033
4000463055	26301	7,190	4/21/2022	5/17/2022	26	0.002%	0.0005
4000463138	106699	2,257	4/22/2022	5/18/2022	26	0.001%	0.0002
4000463279	142942	2,863	4/28/2022	5/24/2022	26	0.001%	0.0002
4000463609	11427	10,150	5/6/2022	6/1/2022	26	0.003%	0.0007
4000463759	27230	125,351	5/13/2022	6/8/2022	26	0.033%	0.0086
4000463971	34616	882	5/18/2022	6/13/2022	26	0.000%	0.0001
4000463941	134862	378,749	5/18/2022	6/13/2022	26	0.100%	0.0260
4000463995	144794	11,800	5/19/2022	6/14/2022	26	0.003%	0.0008
4000464213	24885	350	5/26/2022	6/21/2022	26	0.000%	0.0000
4000464292	13534	2,124	5/27/2022	6/22/2022	26	0.001%	0.0001
4000464296	30252	7,752	5/27/2022	6/22/2022	26	0.002%	0.0005
4000464369	103265	11,584	6/1/2022	6/27/2022	26	0.003%	0.0008
4000464382	142942	1,179	6/1/2022	6/27/2022	26	0.000%	0.0001
4000464473	25029	832	6/2/2022	6/28/2022	26	0.000%	0.0001
4000464675	34616	14,685	6/9/2022	7/5/2022	26	0.004%	0.0010
4000465046	30124	2,530	6/22/2022	7/18/2022	26	0.001%	0.0002
4000465102	34616	21,137	6/23/2022	7/19/2022	26	0.006%	0.0014
4000465296	143473	500	6/30/2022	7/26/2022	26	0.000%	0.0000
4000465413	142942	17,733	7/1/2022	7/27/2022	26	0.005%	0.0012
4000465825	141754	23,000	7/15/2022	8/10/2022	26	0.006%	0.0016
4000465827	142681	194,528	7/15/2022	8/10/2022	26	0.051%	0.0133
4000466041	142942	14,636	7/22/2022	8/17/2022	26	0.004%	0.0010
4000466248	34616	14,530	7/28/2022	8/23/2022	26	0.004%	0.0010

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466332	34173	10,919	7/29/2022	8/24/2022	26	0.003%	0.0007
4000466548	143137	10,224	8/5/2022	8/31/2022	26	0.003%	0.0007
4000466751	13911	1,640	8/11/2022	9/6/2022	26	0.000%	0.0001
4000466921	24113	1,550	8/17/2022	9/12/2022	26	0.000%	0.0001
4000467411	142942	2,900	9/1/2022	9/27/2022	26	0.001%	0.0002
4000467778	17293	6,000	9/15/2022	10/11/2022	26	0.002%	0.0004
4000467979	34616	3,428	9/21/2022	10/17/2022	26	0.001%	0.0002
4000468060	142942	19,828	9/23/2022	10/19/2022	26	0.005%	0.0014
4000468219	123915	1,635	9/28/2022	10/24/2022	26	0.000%	0.0001
4000468229	138707	2,500	9/28/2022	10/24/2022	26	0.001%	0.0002
4000468592	27962	479	10/7/2022	11/2/2022	26	0.000%	0.0000
4000468705	138342	1,417	10/12/2022	11/7/2022	26	0.000%	0.0001
4000468711	143189	9,690	10/12/2022	11/7/2022	26	0.003%	0.0007
4000468824	25029	7,852	10/14/2022	11/9/2022	26	0.002%	0.0005
4000469255	135537	26,110	10/26/2022	11/21/2022	26	0.007%	0.0018
4000469294	9891	24,350	10/27/2022	11/22/2022	26	0.006%	0.0017
4000469532	23681	6,367	11/2/2022	11/28/2022	26	0.002%	0.0004
4000469569	143807	1,400	11/3/2022	11/29/2022	26	0.000%	0.0001
4000469635	8998	24,676	11/4/2022	11/30/2022	26	0.007%	0.0017
4000469644	26299	5,582	11/4/2022	11/30/2022	26	0.001%	0.0004
4000469922	23681	1,061	11/16/2022	12/12/2022	26	0.000%	0.0001
4000470195	8392	11,143	11/23/2022	12/19/2022	26	0.003%	0.0008
4000470228	135537	13,313	11/23/2022	12/19/2022	26	0.004%	0.0009
4000471021	34616	8,188	12/16/2022	1/11/2023	26	0.002%	0.0006
4000470942	126715	10,500	12/16/2022	1/11/2023	26	0.003%	0.0007
4000470954	141754	23,000	12/16/2022	1/11/2023	26	0.006%	0.0016
4000470919	129857	10,258	12/16/2022	1/11/2023	26	0.003%	0.0007
4000471208	28619	3,696	12/22/2022	1/17/2023	26	0.001%	0.0003
4000471318	23681	2,653	12/28/2022	1/23/2023	26	0.001%	0.0002
4000471329	30475	49,723	12/28/2022	1/23/2023	26	0.013%	0.0034
4000471414	134485	16,148	12/29/2022	1/24/2023	26	0.004%	0.0011
4000471502	30475	51,936	12/30/2022	1/25/2023	26	0.014%	0.0036
4000471503	30475	53,371	12/30/2022	1/25/2023	26	0.014%	0.0037
4000471504	30475	60,921	12/30/2022	1/25/2023	26	0.016%	0.0042
4000471505	30475	67,404	12/30/2022	1/25/2023	26	0.018%	0.0046
4000471506	30475	69,694	12/30/2022	1/25/2023	26	0.018%	0.0048
4000471507	30475	75,176	12/30/2022	1/25/2023	26	0.020%	0.0052
4000471440	130634	14,837	12/30/2022	1/25/2023	26	0.004%	0.0010
4000459595	129383	11,232	1/5/2022	2/1/2022	27	0.003%	0.0008
4000459598	142942	376	1/5/2022	2/1/2022	27	0.000%	0.0000
4000459637	144422	56,021	1/6/2022	2/2/2022	27	0.015%	0.0040
4000459809	125852	8,400	1/13/2022	2/9/2022	27	0.002%	0.0006
4000459893	141826	18,620	1/14/2022	2/10/2022	27	0.005%	0.0013
4000459899	144724	282,405	1/14/2022	2/10/2022	27	0.074%	0.0201
4000460000	28619	1,150	1/18/2022	2/14/2022	27	0.000%	0.0001
4000460036	24292	1,390	1/19/2022	2/15/2022	27	0.000%	0.0001
4000460302	28619	836	1/26/2022	2/22/2022	27	0.000%	0.0001
4000460447	125016	493	1/27/2022	2/23/2022	27	0.000%	0.0000
4000460330	142942	19,269	1/27/2022	2/23/2022	27	0.005%	0.0014
4000460473	25029	5,980	1/28/2022	2/24/2022	27	0.002%	0.0004
4000460726	25266	1,451	2/3/2022	3/2/2022	27	0.000%	0.0001
4000461037	28619	732	2/11/2022	3/10/2022	27	0.000%	0.0001
4000461106	100893	848	2/16/2022	3/15/2022	27	0.000%	0.0001

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461114	111081	250	2/16/2022	3/15/2022	27	0.000%	0.0000
4000461260	34616	6,603	2/18/2022	3/17/2022	27	0.002%	0.0005
4000461284	133437	7,500	2/22/2022	3/21/2022	27	0.002%	0.0005
4000461373	100893	7,200	2/24/2022	3/23/2022	27	0.002%	0.0005
4000462038	24211	2,200	3/18/2022	4/14/2022	27	0.001%	0.0002
4000462169	25266	2,027	3/24/2022	4/20/2022	27	0.001%	0.0001
4000462294	142942	11,057	3/29/2022	4/25/2022	27	0.003%	0.0008
4000462355	137788	1,000	3/30/2022	4/26/2022	27	0.000%	0.0001
4000462436	11474	850	3/31/2022	4/27/2022	27	0.000%	0.0001
4000462445	26453	1,287	3/31/2022	4/27/2022	27	0.000%	0.0001
4000462521	11427	8,050	4/1/2022	4/28/2022	27	0.002%	0.0006
4000462527	25029	1,456	4/1/2022	4/28/2022	27	0.000%	0.0001
4000462685	34616	3,513	4/7/2022	5/4/2022	27	0.001%	0.0003
4000463047	145059	2,000	4/21/2022	5/18/2022	27	0.001%	0.0001
4000463190	145053	1,159	4/26/2022	5/23/2022	27	0.000%	0.0001
4000463224	142942	1,073	4/27/2022	5/24/2022	27	0.000%	0.0001
4000463401	125016	2,779	4/29/2022	5/26/2022	27	0.001%	0.0002
4000463612	24885	4,975	5/6/2022	6/2/2022	27	0.001%	0.0004
4000463708	145015	23,324	5/11/2022	6/7/2022	27	0.006%	0.0017
4000464333	142942	7,961	5/31/2022	6/27/2022	27	0.002%	0.0006
4000464464	144858	400	6/2/2022	6/29/2022	27	0.000%	0.0000
4000464641	34616	2,422	6/8/2022	7/5/2022	27	0.001%	0.0002
4000464944	24885	700	6/17/2022	7/14/2022	27	0.000%	0.0000
4000465052	34616	3,588	6/22/2022	7/19/2022	27	0.001%	0.0003
4000465254	11427	20,150	6/28/2022	7/25/2022	27	0.005%	0.0014
4000465332	142942	2,231	6/30/2022	7/27/2022	27	0.001%	0.0002
4000466131	143189	18,285	7/26/2022	8/22/2022	27	0.005%	0.0013
4000466677	145170	1,032	8/10/2022	9/6/2022	27	0.000%	0.0001
4000466897	125016	1,434	8/16/2022	9/12/2022	27	0.000%	0.0001
4000466922	24114	1,100	8/17/2022	9/13/2022	27	0.000%	0.0001
4000466972	34616	3,616	8/18/2022	9/14/2022	27	0.001%	0.0003
4000467329	34616	5,160	8/30/2022	9/26/2022	27	0.001%	0.0004
4000467294	111559	75,284	8/30/2022	9/26/2022	27	0.020%	0.0054
4000467333	103265	12,530	8/31/2022	9/27/2022	27	0.003%	0.0009
4000467361	142942	2,224	8/31/2022	9/27/2022	27	0.001%	0.0002
4000467510	145152	8,240	9/2/2022	9/29/2022	27	0.002%	0.0006
4000467552	145028	15,000	9/6/2022	10/3/2022	27	0.004%	0.0011
4000467655	18267	20,781	9/9/2022	10/6/2022	27	0.005%	0.0015
4000467626	105195	12,726	9/9/2022	10/6/2022	27	0.003%	0.0009
4000467752	24292	9,381	9/14/2022	10/11/2022	27	0.002%	0.0007
4000467770	125016	10,397	9/14/2022	10/11/2022	27	0.003%	0.0007
4000467718	17293	3,000	9/14/2022	10/11/2022	27	0.001%	0.0002
4000467721	103603	3,049	9/14/2022	10/11/2022	27	0.001%	0.0002
4000468485	26588	5,135	10/5/2022	11/1/2022	27	0.001%	0.0004
4000468631	143189	6,353	10/11/2022	11/7/2022	27	0.002%	0.0005
4000468678	30580	451	10/12/2022	11/8/2022	27	0.000%	0.0000
4000469197	24885	350	10/25/2022	11/21/2022	27	0.000%	0.0000
4000469204	135537	16,953	10/25/2022	11/21/2022	27	0.004%	0.0012
4000469703	24885	700	11/8/2022	12/5/2022	27	0.000%	0.0000
4000469900	125016	2,017	11/15/2022	12/12/2022	27	0.001%	0.0001
4000470386	125016	3,361	11/30/2022	12/27/2022	27	0.001%	0.0002
4000470742	135537	22,563	12/9/2022	1/5/2023	27	0.006%	0.0016
4000470717	144794	7,400	12/9/2022	1/5/2023	27	0.002%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470875	24114	4,125	12/15/2022	1/11/2023	27	0.001%	0.0003
4000471004	25029	6,240	12/16/2022	1/12/2023	27	0.002%	0.0004
4000470947	134906	3,900	12/16/2022	1/12/2023	27	0.001%	0.0003
4000471146	24211	4,040	12/21/2022	1/17/2023	27	0.001%	0.0003
4000471166	28619	1,120	12/21/2022	1/17/2023	27	0.000%	0.0001
4000471201	145501	1,202	12/22/2022	1/18/2023	27	0.000%	0.0001
4000471219	14300	198	12/23/2022	1/19/2023	27	0.000%	0.0000
4000459584	23681	9,869	1/4/2022	2/1/2022	28	0.003%	0.0007
4000459581	142942	46	1/4/2022	2/1/2022	28	0.000%	0.0000
4000459864	25029	1,664	1/13/2022	2/10/2022	28	0.000%	0.0001
4000460253	23681	6,686	1/25/2022	2/22/2022	28	0.002%	0.0005
4000460283	142942	1,338	1/26/2022	2/23/2022	28	0.000%	0.0001
4000460718	34616	1,580	2/2/2022	3/2/2022	28	0.000%	0.0001
4000460774	123383	10,925	2/4/2022	3/4/2022	28	0.003%	0.0008
4000460928	107932	10,000	2/10/2022	3/10/2022	28	0.003%	0.0007
4000460930	144893	400	2/10/2022	3/10/2022	28	0.000%	0.0000
4000460931	144893	4,500	2/10/2022	3/10/2022	28	0.001%	0.0003
4000461023	142942	24,631	2/11/2022	3/11/2022	28	0.006%	0.0018
4000460978	102473	650	2/11/2022	3/11/2022	28	0.000%	0.0000
4000461205	34616	5,500	2/17/2022	3/17/2022	28	0.001%	0.0004
4000461351	26301	2,397	2/23/2022	3/23/2022	28	0.001%	0.0002
4000461592	23681	3,184	3/2/2022	3/30/2022	28	0.001%	0.0002
4000461624	11427	13,450	3/3/2022	3/31/2022	28	0.004%	0.0010
4000462237	34616	10,106	3/25/2022	4/22/2022	28	0.003%	0.0007
4000462261	24885	1,350	3/28/2022	4/25/2022	28	0.000%	0.0001
4000462253	142942	2,541	3/28/2022	4/25/2022	28	0.001%	0.0002
4000462413	111570	2,500	3/31/2022	4/28/2022	28	0.001%	0.0002
4000462554	130375	1,000	4/4/2022	5/2/2022	28	0.000%	0.0001
4000462642	34616	3,431	4/6/2022	5/4/2022	28	0.001%	0.0003
4000462902	25029	2,444	4/14/2022	5/12/2022	28	0.001%	0.0002
4000463188	142942	4,096	4/26/2022	5/24/2022	28	0.001%	0.0003
4000463541	34531	4,589	5/4/2022	6/1/2022	28	0.001%	0.0003
4000463679	30252	8,664	5/10/2022	6/7/2022	28	0.002%	0.0006
4000463866	142718	25,000	5/16/2022	6/13/2022	28	0.007%	0.0018
4000463919	145112	6,303	5/17/2022	6/14/2022	28	0.002%	0.0005
4000464013	135537	12,780	5/19/2022	6/16/2022	28	0.003%	0.0009
4000464238	102473	2,428	5/27/2022	6/24/2022	28	0.001%	0.0002
4000464586	144540	13,780	6/7/2022	7/5/2022	28	0.004%	0.0010
4000464759	24211	7,272	6/13/2022	7/11/2022	28	0.002%	0.0005
4000464746	123383	17,058	6/13/2022	7/11/2022	28	0.004%	0.0013
4000464989	141642	1,500	6/20/2022	7/18/2022	28	0.000%	0.0001
4000465009	145198	8,247	6/21/2022	7/19/2022	28	0.002%	0.0006
4000465035	145187	15,000	6/22/2022	7/20/2022	28	0.004%	0.0011
4000465192	141639	500	6/27/2022	7/25/2022	28	0.000%	0.0000
4000465282	142942	248	6/29/2022	7/27/2022	28	0.000%	0.0000
4000465452	28084	42,085	7/1/2022	7/29/2022	28	0.011%	0.0031
4000465608	26301	4,344	7/8/2022	8/5/2022	28	0.001%	0.0003
4000465885	26301	599	7/18/2022	8/15/2022	28	0.000%	0.0000
4000465926	33022	11,537	7/19/2022	8/16/2022	28	0.003%	0.0009
4000466303	26382	5,080	7/29/2022	8/26/2022	28	0.001%	0.0004
4000466676	144669	200	8/10/2022	9/7/2022	28	0.000%	0.0000
4000466937	34616	7,351	8/17/2022	9/14/2022	28	0.002%	0.0005
4000467096	143189	6,647	8/23/2022	9/20/2022	28	0.002%	0.0005

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000467304	142942	6,488	8/30/2022	9/27/2022	28	0.002%	0.0005
4000467525	30252	10,488	9/2/2022	9/30/2022	28	0.003%	0.0008
4000467505	144858	400	9/2/2022	9/30/2022	28	0.000%	0.0000
4000467719	25266	926	9/14/2022	10/12/2022	28	0.000%	0.0001
4000467722	105195	574	9/14/2022	10/12/2022	28	0.000%	0.0000
4000467959	116902	550	9/21/2022	10/19/2022	28	0.000%	0.0000
4000468204	101435	15,000	9/28/2022	10/26/2022	28	0.004%	0.0011
4000468237	145364	1,000	9/28/2022	10/26/2022	28	0.000%	0.0001
4000468421	34616	19,500	9/30/2022	10/28/2022	28	0.005%	0.0014
4000468782	125016	986	10/13/2022	11/10/2022	28	0.000%	0.0001
4000469069	34616	17,817	10/20/2022	11/17/2022	28	0.005%	0.0013
4000469070	34616	15,878	10/20/2022	11/17/2022	28	0.004%	0.0012
4000469166	103265	12,409	10/25/2022	11/22/2022	28	0.003%	0.0009
4000469372	24211	4,040	10/28/2022	11/25/2022	28	0.001%	0.0003
4000469355	143520	2,245	10/28/2022	11/25/2022	28	0.001%	0.0002
4000469549	11427	10,750	11/3/2022	12/1/2022	28	0.003%	0.0008
4000469645	26382	437	11/4/2022	12/2/2022	28	0.000%	0.0000
4000469748	23681	3,184	11/9/2022	12/7/2022	28	0.001%	0.0002
4000470030	24114	2,530	11/18/2022	12/16/2022	28	0.001%	0.0002
4000470328	126135	2,563	11/30/2022	12/28/2022	28	0.001%	0.0002
4000470582	139275	205	12/6/2022	1/3/2023	28	0.000%	0.0000
4000470571	130231	44,207	12/6/2022	1/3/2023	28	0.012%	0.0033
4000470572	143756	7,969	12/6/2022	1/3/2023	28	0.002%	0.0006
4000470689	135537	30,153	12/8/2022	1/5/2023	28	0.008%	0.0022
4000470648	22798	42,090	12/8/2022	1/5/2023	28	0.011%	0.0031
4000470754	142681	75,655	12/12/2022	1/9/2023	28	0.020%	0.0056
4000470784	125009	14,655	12/13/2022	1/10/2023	28	0.004%	0.0011
4000470841	14463	12,405	12/14/2022	1/11/2023	28	0.003%	0.0009
4000470866	34616	4,583	12/14/2022	1/11/2023	28	0.001%	0.0003
4000470909	27013	694	12/15/2022	1/12/2023	28	0.000%	0.0001
4000471025	135537	12,825	12/16/2022	1/13/2023	28	0.003%	0.0009
4000470967	143364	12,300	12/16/2022	1/13/2023	28	0.003%	0.0009
4000471112	32138	7,865	12/21/2022	1/18/2023	28	0.002%	0.0006
4000471501	30365	1,520	12/30/2022	1/27/2023	28	0.000%	0.0001
4000459552	142942	764	1/3/2022	2/1/2022	29	0.000%	0.0001
4000459712	9673	9,925	1/10/2022	2/8/2022	29	0.003%	0.0008
4000459754	8043	704	1/11/2022	2/9/2022	29	0.000%	0.0001
4000459876	106699	9,836	1/13/2022	2/11/2022	29	0.003%	0.0008
4000460022	143216	798,208	1/19/2022	2/17/2022	29	0.211%	0.0611
4000460023	143216	949,281	1/19/2022	2/17/2022	29	0.250%	0.0726
4000460024	143216	1,039,334	1/19/2022	2/17/2022	29	0.274%	0.0795
4000460231	103131	1,668	1/25/2022	2/23/2022	29	0.000%	0.0001
4000460243	142942	2,421	1/25/2022	2/23/2022	29	0.001%	0.0002
4000460281	126099	73,000	1/26/2022	2/24/2022	29	0.019%	0.0056
4000460425	13911	6,675	1/27/2022	2/25/2022	29	0.002%	0.0005
4000460321	108238	19,200	1/27/2022	2/25/2022	29	0.005%	0.0015
4000460946	142942	6,322	2/10/2022	3/11/2022	29	0.002%	0.0005
4000461493	143811	800	2/28/2022	3/29/2022	29	0.000%	0.0001
4000461702	8998	95,503	3/7/2022	4/5/2022	29	0.025%	0.0073
4000461876	118635	4,560	3/15/2022	4/13/2022	29	0.001%	0.0003
4000462193	34616	17,149	3/24/2022	4/22/2022	29	0.005%	0.0013
4000462240	142269	15,000	3/28/2022	4/26/2022	29	0.004%	0.0011
4000462798	28619	18,093	4/12/2022	5/11/2022	29	0.005%	0.0014

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000462831	137743	2,000	4/13/2022	5/12/2022	29	0.001%	0.0002
4000463159	142942	6,190	4/25/2022	5/24/2022	29	0.002%	0.0005
4000463826	25266	1,675	5/16/2022	6/14/2022	29	0.000%	0.0001
4000464591	145179	4,508	6/7/2022	7/6/2022	29	0.001%	0.0003
4000465250	142942	9,682	6/28/2022	7/27/2022	29	0.003%	0.0007
4000465527	34616	12,636	7/6/2022	8/4/2022	29	0.003%	0.0010
4000465687	33058	300	7/11/2022	8/9/2022	29	0.000%	0.0000
4000466128	142874	12,939	7/26/2022	8/24/2022	29	0.003%	0.0010
4000466186	14463	24,920	7/27/2022	8/25/2022	29	0.007%	0.0019
4000466878	141754	23,000	8/16/2022	9/14/2022	29	0.006%	0.0018
4000467274	142942	7,048	8/29/2022	9/27/2022	29	0.002%	0.0005
4000467586	105195	1,345	9/7/2022	10/6/2022	29	0.000%	0.0001
4000467568	105195	16,156	9/7/2022	10/6/2022	29	0.004%	0.0012
4000467992	116517	4,036	9/22/2022	10/21/2022	29	0.001%	0.0003
4000468881	26301	31,308	10/17/2022	11/15/2022	29	0.008%	0.0024
4000468915	141754	23,000	10/18/2022	11/16/2022	29	0.006%	0.0018
4000468969	34616	13,401	10/19/2022	11/17/2022	29	0.004%	0.0010
4000469157	145404	500	10/24/2022	11/22/2022	29	0.000%	0.0000
4000469298	24211	6,616	10/27/2022	11/25/2022	29	0.002%	0.0005
4000470087	8998	41,115	11/21/2022	12/20/2022	29	0.011%	0.0031
4000470222	34616	19,337	11/23/2022	12/22/2022	29	0.005%	0.0015
4000470182	143994	31,872	11/23/2022	12/22/2022	29	0.008%	0.0024
4000470231	22798	88,898	11/28/2022	12/27/2022	29	0.023%	0.0068
4000470671	20063	7,018	12/8/2022	1/6/2023	29	0.002%	0.0005
4000470666	144530	71,046	12/8/2022	1/6/2023	29	0.019%	0.0054
4000470806	34616	3,925	12/13/2022	1/11/2023	29	0.001%	0.0003
4000470857	27013	22,139	12/14/2022	1/12/2023	29	0.006%	0.0017
4000471368	8998	20,152	12/29/2022	1/27/2023	29	0.005%	0.0015
4000471408	32875	3,800	12/29/2022	1/27/2023	29	0.001%	0.0003
4000460145	142942	3,272	1/24/2022	2/23/2022	30	0.001%	0.0003
4000460895	142942	3,618	2/9/2022	3/11/2022	30	0.001%	0.0003
4000461760	106699	8,947	3/9/2022	4/8/2022	30	0.002%	0.0007
4000463143	114658	25,500	4/25/2022	5/25/2022	30	0.007%	0.0020
4000463874	145078	1,000	5/16/2022	6/15/2022	30	0.000%	0.0001
4000464557	13911	3,239	6/6/2022	7/6/2022	30	0.001%	0.0003
4000464578	132103	500	6/7/2022	7/7/2022	30	0.000%	0.0000
4000464830	123768	5,000	6/15/2022	7/15/2022	30	0.001%	0.0004
4000465194	142942	6,435	6/27/2022	7/27/2022	30	0.002%	0.0005
4000465492	34616	7,146	7/5/2022	8/4/2022	30	0.002%	0.0006
4000466850	34616	19,292	8/15/2022	9/14/2022	30	0.005%	0.0015
4000466890	25029	10,244	8/16/2022	9/15/2022	30	0.003%	0.0008
4000467748	9891	9,302	9/14/2022	10/14/2022	30	0.002%	0.0007
4000467919	123383	28,905	9/20/2022	10/20/2022	30	0.008%	0.0023
4000470600	6351	77,820	12/7/2022	1/6/2023	30	0.021%	0.0062
4000470761	8998	57,164	12/12/2022	1/11/2023	30	0.015%	0.0045
4000470753	141583	496	12/12/2022	1/11/2023	30	0.000%	0.0000
4000459570	107932	625	1/4/2022	2/4/2022	31	0.000%	0.0001
4000459571	107932	200	1/4/2022	2/4/2022	31	0.000%	0.0000
4000459724	25908	7,875	1/10/2022	2/10/2022	31	0.002%	0.0006
4000460127	107932	65	1/24/2022	2/24/2022	31	0.000%	0.0000
4000460128	107932	230	1/24/2022	2/24/2022	31	0.000%	0.0000
4000460249	8043	1,124	1/25/2022	2/25/2022	31	0.000%	0.0001
4000460597	25708	9,969	1/31/2022	3/3/2022	31	0.003%	0.0008

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460871	142942	3,162	2/8/2022	3/11/2022	31	0.001%	0.0003
4000460981	115957	125	2/11/2022	3/14/2022	31	0.000%	0.0000
4000462230	24885	1,050	3/25/2022	4/25/2022	31	0.000%	0.0001
4000462217	142942	10,726	3/25/2022	4/25/2022	31	0.003%	0.0009
4000462710	143384	205	4/8/2022	5/9/2022	31	0.000%	0.0000
4000463404	129755	660	5/2/2022	6/2/2022	31	0.000%	0.0001
4000463405	129755	340	5/2/2022	6/2/2022	31	0.000%	0.0000
4000463821	34616	11,929	5/13/2022	6/13/2022	31	0.003%	0.0010
4000463906	135537	4,500	5/16/2022	6/16/2022	31	0.001%	0.0004
4000464276	142942	32,208	5/27/2022	6/27/2022	31	0.008%	0.0026
4000465108	107932	430	6/24/2022	7/25/2022	31	0.000%	0.0000
4000465382	10439	1,540	7/1/2022	8/1/2022	31	0.000%	0.0001
4000465406	130634	40,344	7/1/2022	8/1/2022	31	0.011%	0.0033
4000465815	10439	440	7/15/2022	8/15/2022	31	0.000%	0.0000
4000465818	104990	29,592	7/15/2022	8/15/2022	31	0.008%	0.0024
4000466615	120010	3,325	8/9/2022	9/9/2022	31	0.001%	0.0003
4000467683	14463	30,596	9/12/2022	10/13/2022	31	0.008%	0.0025
4000467882	34616	19,811	9/16/2022	10/17/2022	31	0.005%	0.0016
4000468146	144346	92,393	9/27/2022	10/28/2022	31	0.024%	0.0076
4000468375	144344	9,300	9/30/2022	10/31/2022	31	0.002%	0.0008
4000468891	34616	14,290	10/17/2022	11/17/2022	31	0.004%	0.0012
4000468863	131989	5,000	10/17/2022	11/17/2022	31	0.001%	0.0004
4000469370	23681	4,233	10/28/2022	11/28/2022	31	0.001%	0.0003
4000469430	145222	7,418	10/31/2022	12/1/2022	31	0.002%	0.0006
4000469846	132202	26,253	11/14/2022	12/15/2022	31	0.007%	0.0021
4000469869	145498	5,000	11/15/2022	12/16/2022	31	0.001%	0.0004
4000470773	27013	5,621	12/12/2022	1/12/2023	31	0.001%	0.0005
4000471487	25029	624	12/30/2022	1/30/2023	31	0.000%	0.0001
4000460822	142942	8,957	2/7/2022	3/11/2022	32	0.002%	0.0008
4000461180	143272	17,469	2/17/2022	3/21/2022	32	0.005%	0.0015
4000461212	25266	6,222	2/18/2022	3/22/2022	32	0.002%	0.0005
4000461410	25266	1,545	2/25/2022	3/29/2022	32	0.000%	0.0001
4000461654	144927	18,000	3/4/2022	4/5/2022	32	0.005%	0.0015
4000462179	142942	6,325	3/24/2022	4/25/2022	32	0.002%	0.0005
4000462226	8998	37,298	3/25/2022	4/26/2022	32	0.010%	0.0031
4000463101	142942	19,316	4/22/2022	5/24/2022	32	0.005%	0.0016
4000463859	132905	1,000	5/16/2022	6/17/2022	32	0.000%	0.0001
4000464568	26679	6,500	6/6/2022	7/8/2022	32	0.002%	0.0005
4000464575	135537	13,670	6/6/2022	7/8/2022	32	0.004%	0.0012
4000464968	34616	60,999	6/17/2022	7/19/2022	32	0.016%	0.0051
4000465163	30252	10,384	6/24/2022	7/26/2022	32	0.003%	0.0009
4000465795	24885	5,400	7/14/2022	8/15/2022	32	0.001%	0.0005
4000466601	26301	1,798	8/8/2022	9/9/2022	32	0.000%	0.0002
4000467220	142942	19,656	8/26/2022	9/27/2022	32	0.005%	0.0017
4000467534	105195	1,572	9/2/2022	10/4/2022	32	0.000%	0.0001
4000467461	105195	22,073	9/2/2022	10/4/2022	32	0.006%	0.0019
4000467828	34616	5,047	9/15/2022	10/17/2022	32	0.001%	0.0004
4000468074	25644	7,195	9/23/2022	10/25/2022	32	0.002%	0.0006
4000468127	34616	4,810	9/26/2022	10/28/2022	32	0.001%	0.0004
4000468317	25266	160	9/30/2022	11/1/2022	32	0.000%	0.0000
4000469806	144422	4,402	11/10/2022	12/12/2022	32	0.001%	0.0004
4000470468	137912	4,052	12/2/2022	1/3/2023	32	0.001%	0.0003
4000470562	145117	500	12/5/2022	1/6/2023	32	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470680	27013	8,461	12/8/2022	1/9/2023	32	0.002%	0.0007
4000470687	34616	10,969	12/8/2022	1/9/2023	32	0.003%	0.0009
4000470714	144422	11,193	12/9/2022	1/10/2023	32	0.003%	0.0009
4000471002	24211	7,575	12/16/2022	1/17/2023	32	0.002%	0.0006
4000470992	145141	892	12/16/2022	1/17/2023	32	0.000%	0.0001
4000471202	23681	3,184	12/22/2022	1/23/2023	32	0.001%	0.0003
4000460737	144668	1,552	2/3/2022	3/8/2022	33	0.000%	0.0001
4000460980	107932	1,000	2/11/2022	3/16/2022	33	0.000%	0.0001
4000461165	25266	536	2/17/2022	3/22/2022	33	0.000%	0.0000
4000461623	8998	19,948	3/3/2022	4/5/2022	33	0.005%	0.0017
4000462152	142942	3,111	3/23/2022	4/25/2022	33	0.001%	0.0003
4000462168	24191	4,436	3/24/2022	4/26/2022	33	0.001%	0.0004
4000462545	34616	16,926	4/1/2022	5/4/2022	33	0.004%	0.0015
4000462628	143189	2,926	4/6/2022	5/9/2022	33	0.001%	0.0003
4000462734	28619	5,016	4/8/2022	5/11/2022	33	0.001%	0.0004
4000464151	142942	58	5/25/2022	6/27/2022	33	0.000%	0.0000
4000464678	107932	295	6/10/2022	7/13/2022	33	0.000%	0.0000
4000464679	107932	295	6/10/2022	7/13/2022	33	0.000%	0.0000
4000464680	107932	330	6/10/2022	7/13/2022	33	0.000%	0.0000
4000465020	11427	27,800	6/22/2022	7/25/2022	33	0.007%	0.0024
4000465131	142942	19,591	6/24/2022	7/27/2022	33	0.005%	0.0017
4000465340	143807	1,058	6/30/2022	8/2/2022	33	0.000%	0.0001
4000465434	25029	4,576	7/1/2022	8/3/2022	33	0.001%	0.0004
4000466816	34616	15,862	8/12/2022	9/14/2022	33	0.004%	0.0014
4000467138	24885	700	8/24/2022	9/26/2022	33	0.000%	0.0001
4000467444	105195	1,439	9/1/2022	10/4/2022	33	0.000%	0.0001
4000467401	105195	4,658	9/1/2022	10/4/2022	33	0.001%	0.0004
4000467769	34616	3,349	9/14/2022	10/17/2022	33	0.001%	0.0003
4000468026	125360	2,780	9/22/2022	10/25/2022	33	0.001%	0.0002
4000468542	25266	1,497	10/7/2022	11/9/2022	33	0.000%	0.0001
4000468765	9891	38,022	10/13/2022	11/15/2022	33	0.010%	0.0033
4000468769	20063	5,929	10/13/2022	11/15/2022	33	0.002%	0.0005
4000469638	23681	4,351	11/4/2022	12/7/2022	33	0.001%	0.0004
4000469608	25266	408	11/4/2022	12/7/2022	33	0.000%	0.0000
4000470435	25029	5,720	12/1/2022	1/3/2023	33	0.002%	0.0005
4000470470	139275	268	12/2/2022	1/4/2023	33	0.000%	0.0000
4000470642	27013	168	12/7/2022	1/9/2023	33	0.000%	0.0000
4000470644	34616	6,493	12/7/2022	1/9/2023	33	0.002%	0.0006
4000470603	29254	6,972	12/7/2022	1/9/2023	33	0.002%	0.0006
4000470682	30475	45,294	12/8/2022	1/10/2023	33	0.012%	0.0039
4000470683	30475	31,864	12/8/2022	1/10/2023	33	0.008%	0.0028
4000470684	30475	35,417	12/8/2022	1/10/2023	33	0.009%	0.0031
4000470685	30475	38,014	12/8/2022	1/10/2023	33	0.010%	0.0033
4000470664	144422	4,821	12/8/2022	1/10/2023	33	0.001%	0.0004
4000470741	34616	8,687	12/9/2022	1/11/2023	33	0.002%	0.0008
4000471144	23681	2,122	12/21/2022	1/23/2023	33	0.001%	0.0002
4000471445	142376	22,680	12/30/2022	2/1/2023	33	0.006%	0.0020
4000460471	24191	184	1/28/2022	3/3/2022	34	0.000%	0.0000
4000460798	30252	29,441	2/4/2022	3/10/2022	34	0.008%	0.0026
4000460927	107932	3,000	2/10/2022	3/16/2022	34	0.001%	0.0003
4000461127	135471	1,500	2/16/2022	3/22/2022	34	0.000%	0.0001
4000461338	143622	6,672	2/23/2022	3/29/2022	34	0.002%	0.0006
4000461520	122574	184	3/1/2022	4/4/2022	34	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461589	8998	22,392	3/2/2022	4/5/2022	34	0.006%	0.0020
4000462125	142942	4,286	3/22/2022	4/25/2022	34	0.001%	0.0004
4000462514	145028	15,000	4/1/2022	5/5/2022	34	0.004%	0.0013
4000462671	145035	42,100	4/7/2022	5/11/2022	34	0.011%	0.0038
4000462842	144422	5,593	4/13/2022	5/17/2022	34	0.001%	0.0005
4000464105	142942	4,799	5/24/2022	6/27/2022	34	0.001%	0.0004
4000464488	132103	4,500	6/3/2022	7/7/2022	34	0.001%	0.0004
4000464489	132103	12,000	6/3/2022	7/7/2022	34	0.003%	0.0011
4000464997	107932	65	6/21/2022	7/25/2022	34	0.000%	0.0000
4000464998	107932	230	6/21/2022	7/25/2022	34	0.000%	0.0000
4000465076	142942	1,449	6/23/2022	7/27/2022	34	0.000%	0.0001
4000465232	10439	3,080	6/28/2022	8/1/2022	34	0.001%	0.0003
4000465284	143994	2,563	6/29/2022	8/2/2022	34	0.001%	0.0002
4000465900	143189	3,145	7/19/2022	8/22/2022	34	0.001%	0.0003
4000465980	34616	2,615	7/20/2022	8/23/2022	34	0.001%	0.0002
4000466492	25266	737	8/4/2022	9/7/2022	34	0.000%	0.0001
4000467186	26381	12,960	8/25/2022	9/28/2022	34	0.003%	0.0012
4000468620	36423	863	10/11/2022	11/14/2022	34	0.000%	0.0001
4000468690	115563	200	10/12/2022	11/15/2022	34	0.000%	0.0000
4000468844	34616	19,454	10/14/2022	11/17/2022	34	0.005%	0.0017
4000469368	11427	16,450	10/28/2022	12/1/2022	34	0.004%	0.0015
4000469374	25029	3,016	10/28/2022	12/1/2022	34	0.001%	0.0003
4000469977	144190	768	11/17/2022	12/21/2022	34	0.000%	0.0001
4000470351	23681	7,647	11/30/2022	1/3/2023	34	0.002%	0.0007
4000470410	131631	4,000	12/1/2022	1/4/2023	34	0.001%	0.0004
4000470733	27013	371	12/9/2022	1/12/2023	34	0.000%	0.0000
4000470735	30475	47,770	12/9/2022	1/12/2023	34	0.013%	0.0043
4000470736	30475	41,378	12/9/2022	1/12/2023	34	0.011%	0.0037
4000470846	24211	1,891	12/14/2022	1/17/2023	34	0.000%	0.0002
4000470860	30475	79,268	12/14/2022	1/17/2023	34	0.021%	0.0071
4000470861	30475	87,983	12/14/2022	1/17/2023	34	0.023%	0.0079
4000471010	30475	47,971	12/16/2022	1/19/2023	34	0.013%	0.0043
4000471011	30475	52,156	12/16/2022	1/19/2023	34	0.014%	0.0047
4000471012	30475	55,818	12/16/2022	1/19/2023	34	0.015%	0.0050
4000471013	30475	36,451	12/16/2022	1/19/2023	34	0.010%	0.0033
4000471014	30475	39,491	12/16/2022	1/19/2023	34	0.010%	0.0035
4000471015	30475	42,110	12/16/2022	1/19/2023	34	0.011%	0.0038
4000471016	30475	43,438	12/16/2022	1/19/2023	34	0.011%	0.0039
4000471062	116902	5,325	12/20/2022	1/23/2023	34	0.001%	0.0005
4000471223	24114	11,440	12/23/2022	1/26/2023	34	0.003%	0.0010
4000471516	34616	14,356	12/30/2022	2/2/2023	34	0.004%	0.0013
4000459718	24211	10,464	1/10/2022	2/14/2022	35	0.003%	0.0010
4000459883	25266	1,016	1/14/2022	2/18/2022	35	0.000%	0.0001
4000460725	24114	245	2/3/2022	3/10/2022	35	0.000%	0.0000
4000461074	125360	9,070	2/14/2022	3/21/2022	35	0.002%	0.0008
4000461695	135445	5,000	3/7/2022	4/11/2022	35	0.001%	0.0005
4000462054	34616	1,631	3/18/2022	4/22/2022	35	0.000%	0.0002
4000462079	142942	678	3/21/2022	4/25/2022	35	0.000%	0.0001
4000462141	127614	32,313	3/23/2022	4/27/2022	35	0.009%	0.0030
4000463248	30252	8,208	4/27/2022	6/1/2022	35	0.002%	0.0008
4000463514	123383	12,345	5/3/2022	6/7/2022	35	0.003%	0.0011
4000463571	208279	38	5/5/2022	6/9/2022	35	0.000%	0.0000
4000463755	135537	14,461	5/12/2022	6/16/2022	35	0.004%	0.0013

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000464003	25029	416	5/19/2022	6/23/2022	35	0.000%	0.0000
4000464083	142942	8,944	5/23/2022	6/27/2022	35	0.002%	0.0008
4000464249	30580	59	5/27/2022	7/1/2022	35	0.000%	0.0000
4000465028	142942	2,704	6/22/2022	7/27/2022	35	0.001%	0.0002
4000465431	23681	4,775	7/1/2022	8/5/2022	35	0.001%	0.0004
4000465442	26301	2,696	7/1/2022	8/5/2022	35	0.001%	0.0002
4000465606	25908	7,125	7/8/2022	8/12/2022	35	0.002%	0.0007
4000465877	143189	2,457	7/18/2022	8/22/2022	35	0.001%	0.0002
4000466149	144858	400	7/26/2022	8/30/2022	35	0.000%	0.0000
4000466175	142102	5,606	7/27/2022	8/31/2022	35	0.001%	0.0005
4000467508	144996	2,500	9/2/2022	10/7/2022	35	0.001%	0.0002
4000468090	34616	27,353	9/23/2022	10/28/2022	35	0.007%	0.0025
4000468780	34616	10,380	10/13/2022	11/17/2022	35	0.003%	0.0010
4000469726	142269	3,000	11/9/2022	12/14/2022	35	0.001%	0.0003
4000469919	145482	5,000	11/16/2022	12/21/2022	35	0.001%	0.0005
4000470442	30475	14,708	12/1/2022	1/5/2023	35	0.004%	0.0014
4000470568	27013	6,237	12/5/2022	1/9/2023	35	0.002%	0.0006
4000470594	30475	976	12/6/2022	1/10/2023	35	0.000%	0.0001
4000470785	131647	10,000	12/13/2022	1/17/2023	35	0.003%	0.0009
4000470814	103008	1,275	12/14/2022	1/18/2023	35	0.000%	0.0001
4000470933	118163	3,651	12/16/2022	1/20/2023	35	0.001%	0.0003
4000471124	133437	10,000	12/21/2022	1/25/2023	35	0.003%	0.0009
4000459970	142942	430	1/18/2022	2/23/2022	36	0.000%	0.0000
4000460920	34616	13,698	2/9/2022	3/17/2022	36	0.004%	0.0013
4000460935	34190	25,148	2/10/2022	3/18/2022	36	0.007%	0.0024
4000461700	144950	3,000	3/7/2022	4/12/2022	36	0.001%	0.0003
4000461675	107932	200	3/7/2022	4/12/2022	36	0.000%	0.0000
4000461999	34616	7,521	3/17/2022	4/22/2022	36	0.002%	0.0007
4000462081	144113	10,000	3/21/2022	4/26/2022	36	0.003%	0.0009
4000462756	144422	7,336	4/11/2022	5/17/2022	36	0.002%	0.0007
4000463415	123383	28,815	5/2/2022	6/7/2022	36	0.008%	0.0027
4000464545	25266	1,016	6/6/2022	7/12/2022	36	0.000%	0.0001
4000465007	142942	4,305	6/21/2022	7/27/2022	36	0.001%	0.0004
4000468138	119078	10,500	9/27/2022	11/2/2022	36	0.003%	0.0010
4000469188	8998	18,799	10/25/2022	11/30/2022	36	0.005%	0.0018
4000469447	30252	10,488	10/31/2022	12/6/2022	36	0.003%	0.0010
4000469582	26301	899	11/3/2022	12/9/2022	36	0.000%	0.0001
4000470073	140947	1,000	11/21/2022	12/27/2022	36	0.000%	0.0001
4000470252	23681	3,502	11/28/2022	1/3/2023	36	0.001%	0.0003
4000470370	30475	31,258	11/30/2022	1/5/2023	36	0.008%	0.0030
4000470614	139128	708	12/7/2022	1/12/2023	36	0.000%	0.0001
4000470777	30475	813	12/12/2022	1/17/2023	36	0.000%	0.0001
4000471073	143384	224	12/20/2022	1/25/2023	36	0.000%	0.0000
4000471145	24114	4,840	12/21/2022	1/26/2023	36	0.001%	0.0005
4000459716	11427	19,550	1/10/2022	2/16/2022	37	0.005%	0.0019
4000461957	34616	13,171	3/16/2022	4/22/2022	37	0.003%	0.0013
4000462823	126353	2,000	4/13/2022	5/20/2022	37	0.001%	0.0002
4000463211	30580	1,397	4/27/2022	6/3/2022	37	0.000%	0.0001
4000463920	25029	11,856	5/17/2022	6/23/2022	37	0.003%	0.0012
4000464574	126775	1,039	6/6/2022	7/13/2022	37	0.000%	0.0001
4000468683	108082	2,500	10/12/2022	11/18/2022	37	0.001%	0.0002
4000469159	8998	24,822	10/24/2022	11/30/2022	37	0.007%	0.0024
4000469849	142718	20,000	11/14/2022	12/21/2022	37	0.005%	0.0020

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470102	132103	13,200	11/22/2022	12/29/2022	37	0.003%	0.0013
4000470581	139128	697	12/6/2022	1/12/2023	37	0.000%	0.0001
4000470615	141173	500	12/7/2022	1/13/2023	37	0.000%	0.0000
4000471044	11427	7,100	12/19/2022	1/25/2023	37	0.002%	0.0007
4000459983	8043	792	1/18/2022	2/25/2022	38	0.000%	0.0001
4000459984	8998	77,024	1/18/2022	2/25/2022	38	0.020%	0.0077
4000460873	144607	15,117	2/8/2022	3/18/2022	38	0.004%	0.0015
4000462025	142942	15,702	3/18/2022	4/25/2022	38	0.004%	0.0016
4000462096	25908	3,750	3/21/2022	4/28/2022	38	0.001%	0.0004
4000464034	142942	7,588	5/20/2022	6/27/2022	38	0.002%	0.0008
4000464035	142942	6,033	5/20/2022	6/27/2022	38	0.002%	0.0006
4000464527	145132	1,022	6/3/2022	7/11/2022	38	0.000%	0.0001
4000465011	11427	11,550	6/21/2022	7/29/2022	38	0.003%	0.0012
4000465113	10439	550	6/24/2022	8/1/2022	38	0.000%	0.0001
4000466975	24114	3,135	8/19/2022	9/26/2022	38	0.001%	0.0003
4000467556	8998	32,260	9/6/2022	10/14/2022	38	0.009%	0.0032
4000468384	144858	400	9/30/2022	11/7/2022	38	0.000%	0.0000
4000470523	23681	5,624	12/2/2022	1/9/2023	38	0.001%	0.0006
4000470529	27013	6,063	12/2/2022	1/9/2023	38	0.002%	0.0006
4000470535	34616	16,088	12/2/2022	1/9/2023	38	0.004%	0.0016
4000470988	144996	2,500	12/16/2022	1/23/2023	38	0.001%	0.0003
4000471230	122581	30,000	12/23/2022	1/30/2023	38	0.008%	0.0030
4000471480	208279	1,845	12/30/2022	2/6/2023	38	0.000%	0.0002
4000460977	125360	6,735	2/10/2022	3/21/2022	39	0.002%	0.0007
4000461682	105097	1,195	3/7/2022	4/15/2022	39	0.000%	0.0001
4000461869	34616	2,892	3/14/2022	4/22/2022	39	0.001%	0.0003
4000462176	126722	1,549	3/24/2022	5/2/2022	39	0.000%	0.0002
4000462717	144422	11,427	4/8/2022	5/17/2022	39	0.003%	0.0012
4000465061	10439	3,355	6/23/2022	8/1/2022	39	0.001%	0.0003
4000465529	106652	14,200	7/7/2022	8/15/2022	39	0.004%	0.0015
4000465869	103455	5,000	7/18/2022	8/26/2022	39	0.001%	0.0005
4000466378	26301	6,067	8/1/2022	9/9/2022	39	0.002%	0.0006
4000466990	126796	6,703	8/19/2022	9/27/2022	39	0.002%	0.0007
4000467201	25266	1,323	8/26/2022	10/4/2022	39	0.000%	0.0001
4000469051	143189	14,794	10/20/2022	11/28/2022	39	0.004%	0.0015
4000469563	139275	268	11/3/2022	12/12/2022	39	0.000%	0.0000
4000470448	34616	7,465	12/1/2022	1/9/2023	39	0.002%	0.0008
4000470530	30475	61,011	12/2/2022	1/10/2023	39	0.016%	0.0063
4000470531	30475	65,021	12/2/2022	1/10/2023	39	0.017%	0.0067
4000470532	30475	49,951	12/2/2022	1/10/2023	39	0.013%	0.0051
4000470491	143364	12,300	12/2/2022	1/10/2023	39	0.003%	0.0013
4000470923	25266	529	12/16/2022	1/24/2023	39	0.000%	0.0001
4000460101	25266	1,182	1/21/2022	3/2/2022	40	0.000%	0.0001
4000463942	142942	961	5/18/2022	6/27/2022	40	0.000%	0.0001
4000464413	130375	15,426	6/1/2022	7/11/2022	40	0.004%	0.0016
4000465086	8998	496	6/23/2022	8/2/2022	40	0.000%	0.0001
4000465809	34616	19,160	7/14/2022	8/23/2022	40	0.005%	0.0020
4000466577	34616	8,428	8/5/2022	9/14/2022	40	0.002%	0.0009
4000467585	34616	2,486	9/7/2022	10/17/2022	40	0.001%	0.0003
4000467984	139796	5,000	9/22/2022	11/1/2022	40	0.001%	0.0005
4000468946	143189	34,749	10/19/2022	11/28/2022	40	0.009%	0.0037
4000469053	143807	1,400	10/20/2022	11/29/2022	40	0.000%	0.0001
4000469108	8998	8,282	10/21/2022	11/30/2022	40	0.002%	0.0009

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470383	34616	2,564	11/30/2022	1/9/2023	40	0.001%	0.0003
4000459772	118782	7,405	1/12/2022	2/22/2022	41	0.002%	0.0008
4000459843	142942	4,764	1/13/2022	2/23/2022	41	0.001%	0.0005
4000461602	103265	10,262	3/2/2022	4/12/2022	41	0.003%	0.0011
4000461537	107932	200	3/2/2022	4/12/2022	41	0.000%	0.0000
4000462042	25908	4,000	3/18/2022	4/28/2022	41	0.001%	0.0004
4000462791	145011	7,004	4/12/2022	5/23/2022	41	0.002%	0.0008
4000463046	144422	18,543	4/21/2022	6/1/2022	41	0.005%	0.0020
4000463748	8043	352	5/12/2022	6/22/2022	41	0.000%	0.0000
4000463916	142942	751	5/17/2022	6/27/2022	41	0.000%	0.0001
4000465771	34616	15,382	7/13/2022	8/23/2022	41	0.004%	0.0017
4000466523	34616	11,059	8/4/2022	9/14/2022	41	0.003%	0.0012
4000468919	143189	9,476	10/18/2022	11/28/2022	41	0.002%	0.0010
4000469737	144530	9,400	11/9/2022	12/20/2022	41	0.002%	0.0010
4000469738	144530	58,931	11/9/2022	12/20/2022	41	0.016%	0.0064
4000469967	126135	1,282	11/17/2022	12/28/2022	41	0.000%	0.0001
4000470308	27013	1,267	11/29/2022	1/9/2023	41	0.000%	0.0001
4000470872	103265	12,494	12/15/2022	1/25/2023	41	0.003%	0.0014
4000470886	125322	33,000	12/15/2022	1/25/2023	41	0.009%	0.0036
4000459582	143189	4,576	1/4/2022	2/15/2022	42	0.001%	0.0005
4000459781	142942	895	1/12/2022	2/23/2022	42	0.000%	0.0001
4000460850	125360	9,675	2/7/2022	3/21/2022	42	0.003%	0.0011
4000462612	144927	6,000	4/5/2022	5/17/2022	42	0.002%	0.0007
4000462815	117160	500	4/13/2022	5/25/2022	42	0.000%	0.0001
4000464394	11304	24,375	6/1/2022	7/13/2022	42	0.006%	0.0027
4000467378	26323	9,621	8/31/2022	10/12/2022	42	0.003%	0.0011
4000467516	8998	34,483	9/2/2022	10/14/2022	42	0.009%	0.0038
4000467605	144422	1,131	9/8/2022	10/20/2022	42	0.000%	0.0001
4000467712	125360	1,455	9/13/2022	10/25/2022	42	0.000%	0.0002
4000468950	8998	55,396	10/19/2022	11/30/2022	42	0.015%	0.0061
4000469485	113747	11,010	11/2/2022	12/14/2022	42	0.003%	0.0012
4000469830	125360	1,610	11/10/2022	12/22/2022	42	0.000%	0.0002
4000470211	30475	60,523	11/23/2022	1/4/2023	42	0.016%	0.0067
4000470212	30475	62,718	11/23/2022	1/4/2023	42	0.017%	0.0069
4000470213	30475	65,609	11/23/2022	1/4/2023	42	0.017%	0.0073
4000470214	30475	68,621	11/23/2022	1/4/2023	42	0.018%	0.0076
4000470215	30475	70,045	11/23/2022	1/4/2023	42	0.018%	0.0078
4000470216	30475	73,461	11/23/2022	1/4/2023	42	0.019%	0.0081
4000470267	27013	3,522	11/28/2022	1/9/2023	42	0.001%	0.0004
4000470870	134485	9,018	12/14/2022	1/25/2023	42	0.002%	0.0010
4000471310	128433	60,000	12/28/2022	2/8/2023	42	0.016%	0.0066
4000471423	22798	1,050	12/30/2022	2/10/2023	42	0.000%	0.0001
4000471424	22798	51,179	12/30/2022	2/10/2023	42	0.013%	0.0057
4000459750	142942	1,846	1/11/2022	2/23/2022	43	0.000%	0.0002
4000459859	8998	18,434	1/13/2022	2/25/2022	43	0.005%	0.0021
4000461270	111108	8,913	2/22/2022	4/6/2022	43	0.002%	0.0010
4000461805	34616	753	3/10/2022	4/22/2022	43	0.000%	0.0001
4000464136	4831	6,795	5/25/2022	7/7/2022	43	0.002%	0.0008
4000464781	30252	9,120	6/13/2022	7/26/2022	43	0.002%	0.0010
4000465093	26301	12,284	6/23/2022	8/5/2022	43	0.003%	0.0014
4000465876	142724	500	7/18/2022	8/30/2022	43	0.000%	0.0001
4000466654	125611	2,500	8/10/2022	9/22/2022	43	0.001%	0.0003
4000467733	140685	200	9/14/2022	10/27/2022	43	0.000%	0.0000

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000468455	26301	1,573	10/3/2022	11/15/2022	43	0.000%	0.0002
4000468923	8998	27,464	10/18/2022	11/30/2022	43	0.007%	0.0031
4000459717	18267	2,188	1/10/2022	2/23/2022	44	0.001%	0.0003
4000461539	116902	2,300	3/2/2022	4/15/2022	44	0.001%	0.0003
4000461540	116902	2,230	3/2/2022	4/15/2022	44	0.001%	0.0003
4000462102	26381	2,000	3/21/2022	5/4/2022	44	0.001%	0.0002
4000462585	144858	400	4/4/2022	5/18/2022	44	0.000%	0.0000
4000462993	30580	1,426	4/20/2022	6/3/2022	44	0.000%	0.0002
4000463010	144435	3,682	4/20/2022	6/3/2022	44	0.001%	0.0004
4000464590	145178	2,429	6/7/2022	7/21/2022	44	0.001%	0.0003
4000464821	32138	23,786	6/15/2022	7/29/2022	44	0.006%	0.0028
4000465934	33080	3,591	7/19/2022	9/1/2022	44	0.001%	0.0004
4000465983	140318	23,401	7/20/2022	9/2/2022	44	0.006%	0.0027
4000466854	113763	4,250	8/16/2022	9/29/2022	44	0.001%	0.0005
4000468870	8998	8,795	10/17/2022	11/30/2022	44	0.002%	0.0010
4000469403	10439	547	10/31/2022	12/14/2022	44	0.000%	0.0001
4000470141	27013	5,449	11/22/2022	1/5/2023	44	0.001%	0.0006
4000460811	129121	650	2/7/2022	3/24/2022	45	0.000%	0.0001
4000463398	34616	4,183	4/29/2022	6/13/2022	45	0.001%	0.0005
4000465889	100271	38,627	7/19/2022	9/2/2022	45	0.010%	0.0046
4000465895	140318	197,405	7/19/2022	9/2/2022	45	0.052%	0.0234
4000465896	140318	262,764	7/19/2022	9/2/2022	45	0.069%	0.0312
4000465897	140318	277,212	7/19/2022	9/2/2022	45	0.073%	0.0329
4000467315	8998	30,077	8/30/2022	10/14/2022	45	0.008%	0.0036
4000468062	143189	4,943	9/23/2022	11/7/2022	45	0.001%	0.0006
4000463320	34616	3,186	4/28/2022	6/13/2022	46	0.001%	0.0004
4000465626	34616	28,257	7/8/2022	8/23/2022	46	0.007%	0.0034
4000469602	4831	6,700	11/4/2022	12/20/2022	46	0.002%	0.0008
4000470028	23681	5,624	11/18/2022	1/3/2023	46	0.001%	0.0007
4000460807	34348	525	2/4/2022	3/23/2022	47	0.000%	0.0001
4000463254	34616	10,378	4/27/2022	6/13/2022	47	0.003%	0.0013
4000465560	34616	13,426	7/7/2022	8/23/2022	47	0.004%	0.0017
4000470203	27013	7,131	11/23/2022	1/9/2023	47	0.002%	0.0009
4000470632	23681	1,061	12/7/2022	1/23/2023	47	0.000%	0.0001
4000460875	144858	400	2/8/2022	3/28/2022	48	0.000%	0.0001
4000461280	130125	5,000	2/22/2022	4/11/2022	48	0.001%	0.0006
4000462888	144422	4,554	4/14/2022	6/1/2022	48	0.001%	0.0006
4000464842	8998	496	6/15/2022	8/2/2022	48	0.000%	0.0001
4000467927	143189	1,636	9/20/2022	11/7/2022	48	0.000%	0.0002
4000467967	143189	3,983	9/21/2022	11/8/2022	48	0.001%	0.0005
4000469658	34616	15,033	11/4/2022	12/22/2022	48	0.004%	0.0019
4000460443	34616	16,678	1/27/2022	3/17/2022	49	0.004%	0.0022
4000461672	34616	3,662	3/4/2022	4/22/2022	49	0.001%	0.0005
4000461697	142885	3,132	3/7/2022	4/25/2022	49	0.001%	0.0004
4000462835	141737	2,500	4/13/2022	6/1/2022	49	0.001%	0.0003
4000462998	117205	7,500	4/20/2022	6/8/2022	49	0.002%	0.0010
4000467665	34616	30,139	9/9/2022	10/28/2022	49	0.008%	0.0039
4000468713	143832	10,000	10/12/2022	11/30/2022	49	0.003%	0.0013
4000469595	34616	19,268	11/3/2022	12/22/2022	49	0.005%	0.0025
4000471221	22798	7,943	12/23/2022	2/10/2023	49	0.002%	0.0010
4000461294	8043	2,922	2/22/2022	4/13/2022	50	0.001%	0.0004
4000464754	8998	28,576	6/13/2022	8/2/2022	50	0.008%	0.0038
4000465874	142354	2,000	7/18/2022	9/6/2022	50	0.001%	0.0003

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000466653	119568	300	8/10/2022	9/29/2022	50	0.000%	0.0000
4000467619	34616	5,982	9/8/2022	10/28/2022	50	0.002%	0.0008
4000468639	8998	434	10/11/2022	11/30/2022	50	0.000%	0.0001
4000469523	144858	400	11/2/2022	12/22/2022	50	0.000%	0.0001
4000460270	34616	974	1/25/2022	3/17/2022	51	0.000%	0.0001
4000461600	34616	3,883	3/2/2022	4/22/2022	51	0.001%	0.0005
4000470209	30475	80,898	11/23/2022	1/13/2023	51	0.021%	0.0109
4000470210	30475	84,607	11/23/2022	1/13/2023	51	0.022%	0.0114
4000471297	125360	11,155	12/27/2022	2/16/2023	51	0.003%	0.0015
4000460166	34616	2,971	1/24/2022	3/17/2022	52	0.001%	0.0004
4000462130	9891	12,893	3/22/2022	5/13/2022	52	0.003%	0.0018
4000463465	130375	65	5/3/2022	6/24/2022	52	0.000%	0.0000
4000465693	33080	3,523	7/11/2022	9/1/2022	52	0.001%	0.0005
4000468470	132103	2,400	10/4/2022	11/25/2022	52	0.001%	0.0003
4000461979	142134	229	3/17/2022	5/9/2022	53	0.000%	0.0000
4000462442	25908	15,250	3/31/2022	5/23/2022	53	0.004%	0.0021
4000467537	125360	600	9/2/2022	10/25/2022	53	0.000%	0.0001
4000469417	129971	5,000	10/31/2022	12/23/2022	53	0.001%	0.0007
4000470762	10384	4,250	12/12/2022	2/3/2023	53	0.001%	0.0006
4000462384	25908	1,500	3/30/2022	5/23/2022	54	0.000%	0.0002
4000462735	30252	39,330	4/8/2022	6/1/2022	54	0.010%	0.0056
4000467358	138051	5,000	8/31/2022	10/24/2022	54	0.001%	0.0007
4000470511	145028	15,000	12/2/2022	1/25/2023	54	0.004%	0.0021
4000470515	145152	8,240	12/2/2022	1/25/2023	54	0.002%	0.0012
4000459655	34616	8,968	1/6/2022	3/2/2022	55	0.002%	0.0013
4000459684	25708	833	1/7/2022	3/3/2022	55	0.000%	0.0001
4000461406	104054	4,200	2/25/2022	4/21/2022	55	0.001%	0.0006
4000467393	125360	1,550	8/31/2022	10/25/2022	55	0.000%	0.0002
4000467914	107932	625	9/20/2022	11/14/2022	55	0.000%	0.0001
4000467915	107932	790	9/20/2022	11/14/2022	55	0.000%	0.0001
4000468260	130375	883	9/28/2022	11/22/2022	55	0.000%	0.0001
4000469393	34616	12,794	10/28/2022	12/22/2022	55	0.003%	0.0019
4000469398	125360	12,995	10/28/2022	12/22/2022	55	0.003%	0.0019
4000469741	145460	1,000	11/9/2022	1/3/2023	55	0.000%	0.0001
4000470223	34658	5,000	11/23/2022	1/17/2023	55	0.001%	0.0007
4000470660	141409	2,200	12/8/2022	2/1/2023	55	0.001%	0.0003
4000471469	145028	15,000	12/30/2022	2/23/2023	55	0.004%	0.0022
4000460167	125360	12,050	1/24/2022	3/21/2022	56	0.003%	0.0018
4000461369	104054	12,000	2/24/2022	4/21/2022	56	0.003%	0.0018
4000467687	103278	35,958	9/13/2022	11/8/2022	56	0.009%	0.0053
4000469323	125360	790	10/27/2022	12/22/2022	56	0.000%	0.0001
4000469836	4831	12,895	11/14/2022	1/9/2023	56	0.003%	0.0019
4000471081	10384	52,900	12/20/2022	2/14/2023	56	0.014%	0.0078
4000462058	100893	3,319	3/21/2022	5/17/2022	57	0.001%	0.0005
4000466835	145262	1,000	8/15/2022	10/11/2022	57	0.000%	0.0002
4000469249	34616	14,094	10/26/2022	12/22/2022	57	0.004%	0.0021
4000470559	144113	3,500	12/5/2022	1/31/2023	57	0.001%	0.0005
4000462591	106141	4,400	4/5/2022	6/2/2022	58	0.001%	0.0007
4000462592	106141	3,900	4/5/2022	6/2/2022	58	0.001%	0.0006
4000462593	106141	2,144	4/5/2022	6/2/2022	58	0.001%	0.0003
4000468444	8998	66,070	10/3/2022	11/30/2022	58	0.017%	0.0101
4000469203	34616	1,380	10/25/2022	12/22/2022	58	0.000%	0.0002
4000469840	107450	10,000	11/14/2022	1/11/2023	58	0.003%	0.0015

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000460123	125360	2,325	1/21/2022	3/21/2022	59	0.001%	0.0004
4000469162	34616	20,238	10/24/2022	12/22/2022	59	0.005%	0.0031
4000468094	103265	12,542	9/23/2022	11/22/2022	60	0.003%	0.0020
4000469821	27013	6,347	11/10/2022	1/9/2023	60	0.002%	0.0010
4000460050	125360	1,705	1/19/2022	3/21/2022	61	0.000%	0.0003
4000461031	8043	1,911	2/11/2022	4/13/2022	61	0.001%	0.0003
4000464470	8998	3,802	6/2/2022	8/2/2022	61	0.001%	0.0006
4000465350	144858	400	6/30/2022	8/30/2022	61	0.000%	0.0001
4000468396	8998	33,109	9/30/2022	11/30/2022	61	0.009%	0.0053
4000469759	27013	1,218	11/9/2022	1/9/2023	61	0.000%	0.0002
4000462469	107932	295	4/1/2022	6/2/2022	62	0.000%	0.0000
4000469125	34616	16,802	10/21/2022	12/22/2022	62	0.004%	0.0027
4000470690	107932	265	12/9/2022	2/9/2023	62	0.000%	0.0000
4000465739	36324	4,000	7/13/2022	9/14/2022	63	0.001%	0.0007
4000469683	27013	3,838	11/7/2022	1/9/2023	63	0.001%	0.0006
4000463682	34173	10,661	5/10/2022	7/13/2022	64	0.003%	0.0018
4000468934	125360	1,800	10/18/2022	12/22/2022	65	0.000%	0.0003
4000470103	144842	16,615	11/22/2022	1/26/2023	65	0.004%	0.0028
4000471038	144120	7,706	12/19/2022	2/22/2023	65	0.002%	0.0013
4000462129	3833	24,206	3/22/2022	5/27/2022	66	0.006%	0.0042
4000463111	144861	1,890	4/22/2022	6/27/2022	66	0.000%	0.0003
4000469648	27013	28,910	11/4/2022	1/9/2023	66	0.008%	0.0050
4000471042	10384	800	12/19/2022	2/23/2023	66	0.000%	0.0001
4000461438	8043	704	2/25/2022	5/3/2022	67	0.000%	0.0001
4000469587	27013	14,576	11/3/2022	1/9/2023	67	0.004%	0.0026
4000459886	104990	29,365	1/14/2022	3/23/2022	68	0.008%	0.0053
4000461763	113357	3,000	3/10/2022	5/18/2022	69	0.001%	0.0005
4000465331	142874	12,939	6/30/2022	9/7/2022	69	0.003%	0.0024
4000466939	125360	29,088	8/17/2022	10/25/2022	69	0.008%	0.0053
4000471281	10384	14,600	12/27/2022	3/6/2023	69	0.004%	0.0027
4000461723	144699	16,500	3/8/2022	5/17/2022	70	0.004%	0.0030
4000465733	129755	1,250	7/13/2022	9/21/2022	70	0.000%	0.0002
4000465734	129755	1,250	7/13/2022	9/21/2022	70	0.000%	0.0002
4000470912	30475	916	12/15/2022	2/23/2023	70	0.000%	0.0002
4000467176	208279	193	8/25/2022	11/4/2022	71	0.000%	0.0000
4000470555	141042	500	12/5/2022	2/14/2023	71	0.000%	0.0001
4000461264	107932	15,000	2/22/2022	5/5/2022	72	0.004%	0.0028
4000461866	144440	1,000	3/14/2022	5/26/2022	73	0.000%	0.0002
4000459856	144858	1,200	1/13/2022	3/28/2022	74	0.000%	0.0002
4000461313	10439	1,760	2/23/2022	5/9/2022	75	0.000%	0.0003
4000468218	122841	1,000	9/28/2022	12/12/2022	75	0.000%	0.0002
4000470651	27230	3,622	12/8/2022	2/21/2023	75	0.001%	0.0007
4000461733	34743	9,015	3/8/2022	5/23/2022	76	0.002%	0.0018
4000461474	101490	10,000	2/28/2022	5/16/2022	77	0.003%	0.0020
4000461837	3833	188,613	3/11/2022	5/27/2022	77	0.050%	0.0383
4000469186	8043	427	10/25/2022	1/10/2023	77	0.000%	0.0001
4000466612	125360	1,740	8/8/2022	10/25/2022	78	0.000%	0.0004
4000469191	11577	6,878	10/25/2022	1/11/2023	78	0.002%	0.0014
4000471057	26130	50,000	12/20/2022	3/8/2023	78	0.013%	0.0103
4000460900	3833	228,831	2/9/2022	4/29/2022	79	0.060%	0.0477
4000462564	141884	10,288	4/4/2022	6/22/2022	79	0.003%	0.0021
4000468848	8043	1,408	10/17/2022	1/5/2023	80	0.000%	0.0003
4000461160	10439	990	2/17/2022	5/9/2022	81	0.000%	0.0002

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000461428	140752	2,460	2/25/2022	5/17/2022	81	0.001%	0.0005
4000466051	8043	995	7/22/2022	10/12/2022	82	0.000%	0.0002
4000467775	131647	5,600	9/15/2022	12/6/2022	82	0.001%	0.0012
4000459642	3833	137,527	1/6/2022	3/31/2022	84	0.036%	0.0305
4000462725	3833	176,936	4/8/2022	7/1/2022	84	0.047%	0.0392
4000459602	3833	11,526	1/5/2022	3/31/2022	85	0.003%	0.0026
4000464664	3833	130,184	6/9/2022	9/2/2022	85	0.034%	0.0292
4000468148	10384	3,050	9/27/2022	12/22/2022	86	0.001%	0.0007
4000463608	3833	181,425	5/6/2022	8/1/2022	87	0.048%	0.0416
4000463856	128780	1,000	5/16/2022	8/12/2022	88	0.000%	0.0002
4000466340	125360	3,035	7/29/2022	10/25/2022	88	0.001%	0.0007
4000463990	142998	8,600	5/19/2022	8/16/2022	89	0.002%	0.0020
4000466252	125360	15,425	7/28/2022	10/25/2022	89	0.004%	0.0036
4000461567	142164	5,356	3/2/2022	5/31/2022	90	0.001%	0.0013
4000464493	28394	3,500	6/3/2022	9/1/2022	90	0.001%	0.0008
4000465496	30580	1,577	7/6/2022	10/4/2022	90	0.000%	0.0004
4000461385	143793	50,180	2/24/2022	5/26/2022	91	0.013%	0.0120
4000469362	3833	14,160	10/28/2022	1/27/2023	91	0.004%	0.0034
4000464166	25808	1,020	5/25/2022	8/25/2022	92	0.000%	0.0002
4000469292	3833	78,222	10/27/2022	1/27/2023	92	0.021%	0.0190
4000460290	3833	18,874	1/26/2022	4/29/2022	93	0.005%	0.0046
4000461694	133558	500	3/7/2022	6/8/2022	93	0.000%	0.0001
4000460121	26679	2,125	1/21/2022	4/25/2022	94	0.001%	0.0005
4000460724	10439	825	2/3/2022	5/9/2022	95	0.000%	0.0002
4000465594	8043	704	7/8/2022	10/12/2022	96	0.000%	0.0002
4000463761	30580	4,057	5/13/2022	8/18/2022	97	0.001%	0.0010
4000462280	116902	1,140	3/29/2022	7/5/2022	98	0.000%	0.0003
4000470194	3833	98,322	11/23/2022	3/1/2023	98	0.026%	0.0254
4000464442	141884	10,321	6/2/2022	9/9/2022	99	0.003%	0.0027
4000468239	8043	352	9/28/2022	1/5/2023	99	0.000%	0.0001
4000463477	141884	10,321	5/3/2022	8/11/2022	100	0.003%	0.0027
4000464805	8043	1,568	6/14/2022	9/26/2022	104	0.000%	0.0004
4000463361	144915	22,505	4/29/2022	8/12/2022	105	0.006%	0.0062
4000465593	3833	180,695	7/8/2022	10/21/2022	105	0.048%	0.0500
4000465253	8043	1,234	6/28/2022	10/12/2022	106	0.000%	0.0003
4000466201	129383	3,600	7/28/2022	11/15/2022	110	0.001%	0.0010
4000465085	8043	3,761	6/23/2022	10/12/2022	111	0.001%	0.0011
4000459670	3833	10,795	1/7/2022	4/29/2022	112	0.003%	0.0032
4000462324	32138	2,715	3/30/2022	7/20/2022	112	0.001%	0.0008
4000463790	3833	54,132	5/13/2022	9/2/2022	112	0.014%	0.0160
4000465325	141884	10,321	6/30/2022	10/20/2022	112	0.003%	0.0030
4000468579	3833	196,126	10/7/2022	1/27/2023	112	0.052%	0.0579
4000469743	3833	80,534	11/9/2022	3/1/2023	112	0.021%	0.0238
4000470721	3833	142,348	12/9/2022	3/31/2023	112	0.038%	0.0421
4000469701	3833	8,731	11/8/2022	3/1/2023	113	0.002%	0.0026
4000469678	3833	26,129	11/7/2022	3/1/2023	114	0.007%	0.0079
4000467651	3833	150,094	9/9/2022	1/3/2023	116	0.040%	0.0459
4000470565	3833	24,754	12/5/2022	3/31/2023	116	0.007%	0.0076
4000467134	3833	49,901	8/24/2022	12/19/2022	117	0.013%	0.0154
4000468258	34616	16,042	9/28/2022	1/23/2023	117	0.004%	0.0050
4000467652	8043	304	9/9/2022	1/5/2023	118	0.000%	0.0001
4000462892	144915	15,423	4/14/2022	8/12/2022	120	0.004%	0.0049
4000470181	143968	14,503	11/23/2022	3/23/2023	120	0.004%	0.0046

Check Number (A)	Vendor Number (B)	Amount (C)	Payment Date (D)	Check Encashment Date (E)	Unweighted Lead (F)	Weighting Factor (G)	Weighted Lead (H)
4000470296	3833	37,892	11/29/2022	3/31/2023	122	0.010%	0.0122
4000468287	10384	3,350	9/29/2022	1/30/2023	123	0.001%	0.0011
4000467515	8043	1,656	9/2/2022	1/5/2023	125	0.000%	0.0005
4000464934	3833	56,892	6/17/2022	10/21/2022	126	0.015%	0.0189
4000468306	34616	17,181	9/29/2022	2/2/2023	126	0.005%	0.0057
4000466722	104031	7,500	8/11/2022	12/16/2022	127	0.002%	0.0025
4000467368	8043	899	8/31/2022	1/5/2023	127	0.000%	0.0003
4000466679	3833	125,732	8/10/2022	12/19/2022	131	0.033%	0.0434
4000464716	3833	39,082	6/10/2022	10/21/2022	133	0.010%	0.0137
4000462597	30580	94	4/5/2022	8/30/2022	147	0.000%	0.0000
4000467949	118029	1,204	9/21/2022	2/17/2023	149	0.000%	0.0005
4000467950	118029	2,409	9/21/2022	2/17/2023	149	0.001%	0.0009
4000462184	145012	500	3/24/2022	8/23/2022	152	0.000%	0.0002
4000466489	111258	600	8/4/2022	1/3/2023	152	0.000%	0.0002
4000467532	34616	36,073	9/2/2022	2/2/2023	153	0.010%	0.0146
4000460926	103278	2,000	2/10/2022	7/19/2022	159	0.001%	0.0008
4000464618	107151	6,125	6/8/2022	11/21/2022	166	0.002%	0.0027
4000460662	144894	256,000	2/1/2022	8/15/2022	195	0.068%	0.1317
4000462801	132364	2,075	4/13/2022	11/18/2022	219	0.001%	0.0012
4000460225	129744	7,950	1/25/2022	11/2/2022	281	0.002%	0.0059
4000460735	128166	1,734	2/3/2022	12/29/2022	329	0.000%	0.0015
		$ 379,137,208				100%	12.23

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
STEPHEN SWETZ

SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS
ON
ELECTRIC COST OF SERVICE AND RATE DESIGN

December 29, 2023
P-9E

TABLE OF CONTENTS

SCOPE OF TESTIMONY ..... - 1 -

SCHEDULE INDEX ..... - 3 -

OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSES ..... - 5 -

Overview ..... - 5 -

Residential Rate Affordability ..... - 7 -

Weather Normalization of Billing Determinants ..... - 15 -

Scope of the Cost of Service Study ..... - 15 -

Adjustments to Accounting Data ..... - 16 -

COST OF SERVICE STUDY ("COSS") OVERVIEW ..... - 16 -

Introduction ..... - 16 -
Cost Allocation Concepts ..... - 17 -
General Cost Allocation and Functionalization Methodology ..... - 18 -
Functionalization of the Six Segments ..... - 23 -
Access Segment ..... - 24 -
Local Delivery Segment ..... - 25 -
System Delivery Segment ..... - 26 -
Street Lighting Segment ..... - 27 -
Customer Service Segment ..... - 27 -
Measurement Segment ..... - 28 -
Modeling Procedures ..... - 28 -
Synchronizing the Cost of Service Study to the Rate Design ..... - 29 -

RATE DESIGN ..... - 31 -

Introduction ..... - 31 -

Limitations on Rate Changes ..... - 32 -

Inter Class Revenue Increase Allocations ..... - 33 -
General Rate Design Principles and Methodology ..... - 34 -

RATE SCHEDULE SPECIFIC CHANGES..... - 37 -

Rate Schedule Residential Service ("RS") ..... - 37 -
Rate Schedule Residential Heating Service ("RHS")..... - 39 -
Rate Schedule Residential Load Management Service ("RLM") ..... - 41 -
Rate Schedule Water Heating Service ("WH") ..... - 42 -
Rate Schedule Water Heating Storage Service ("WHS")..... - 42 -
Rate Schedule Building Heating Service ("HS")..... - 43 -
Rate Schedule General Lighting And Power Service ("GLP") ..... - 43 -
Rate Schedule Large Power And Lighting Service ("LPL")..... - 45 -
Rate Schedule High Tension Service ("HTS")..... - 46 -
Payment Schedule Purchased Electric Power ("PEP")..... - 47 -

ELECTRIC VEHICLE ("EV") COST OF SERVICE STUDIES ("COSS")..... - 47 -

Residential Study..... - 47 -

Commercial & Industrial ("C&I") EV COSS..... - 48 -

PROPOSED RESIDENTIAL TOU RATES..... - 49 -

Overview ..... - 49 -

Rate Design Detail..... - 50 -

Program Details..... - 53 -

PROPOSED DCFC DISTRIBUTION KILOWATT-HOUR CHARGE..... - 57 -

STREETLIGHTING CHANGES..... - 58 -

LED Street Lighting..... - 58 -
Rate Schedule Body Politic Lighting Service ("BPL")..... - 60 -
Rate Schedule Body Politic Lighting Service From Publicly Owned Facilities ("BPL-POF") ..... - 62 -
Rate Schedule Private Street and Area Lighting Service ("PSAL") ..... - 63 -

RATE DESIGN FOR FUTURE ADJUSTMENT BETWEEN BASE RATE CASES..... - 64 -

TAX ADJUSTMENT CREDIT ("TAC")..... - 65 -

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC")- 66 -

SRC Mechanism..... - 66 -

SRC Components..... - 67 -

TARIFF CHANGES..... - 69 -

LOSSES..... - 69 -

CLEAN ENERGY FUTURE – ELECTRIC VEHICLE ("CEF-EV") FUTURE RATE ADJUSTMENT MECHANISM..... - 69 -

STAFF COSS METHODOLOGY..... - 75 -

Accounts E360 to E362, E365, E366, E367 and E368..... - 78 -
Accounts C389 to C399 – Common Plant and E303 Intangible Plant..... - 78 -
Accounts E902 – Meter Reading Expenses & E903 - Customer Records and Collection..... - 79 -
Subsequent Base Case Requirements..... - 79 -

APPENDIX E1 - DETAILED REVIEW OF COST OF SERVICE STUDY..... - 80 -

ALLOCATOR NAMING CONVENTION..... - 80 -

Direct Allocators..... - 80 -
Indirect Allocators..... - 81 -

ALLOCATION DETAILS..... - 82 -

Intangible Plant..... - 82 -
Production Plant..... - 82 -
Transmission Plant..... - 82 -
Distribution Plant..... - 82 -
E370 - Meters..... - 87 -
E373 – Street Light and Signal Systems..... - 88 -
Asset Retirement Obligations..... - 88 -
General, Common and Other Plant..... - 88 -

Depreciation Reserve ..... - 89 -
Adjustments to Develop Rate Base ..... - 89 -
Operating Revenues ..... - 90 -
Production Expenses ..... - 90 -
Transmission O&M Expenses ..... - 91 -
Distribution O&M Expenses ..... - 91 -
Customer Accounts, Service and Sales Expense ..... - 91 -
Administrative and General ("A&G") Expenses ..... - 92 -
Depreciation and Amortization Expenses ..... - 92 -
Pro Forma Expense Adjustments ..... - 92 -
Taxes ..... - 93 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND
REVENUE REQUIREMENTS
ON
ELECTRIC COST OF SERVICE AND RATE DESIGN

Q. Please state your name, affiliation and business address.

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS-El.

Q. Please describe your responsibilities as Senior Director - Corporate Rates and Revenue Requirements.

A. In this position I have, among other things, responsibility for the development of rates and tariffs for Public Service Electric and Gas Company ("PSE&G" or "Company").

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. I have both submitted written testimony and testified live before the BPU in a number of proceedings that are identified in Schedule SS-E1.

SCOPE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's proposed changes to its rates for Electric Service, which are designed to recover the revenue requirements for the electric distribution business as presented in this filing. My testimony provides the Company's embedded cost of service study ("Company COSS") used as the basis for development of the

new electric rates and the proposed rate design for each rate schedule in PSE&G's Electric Tariff. I also present an alternative embedded cost of service study ("the Staff COSS") as required under the 2018 Rate Case Order, and explain why that COSS should not be used to set rates in this case.[1]

Additionally, I sponsor other studies and modifications to the Company's Tariff for Electric Service ("Tariff") including the following:

- The establishment of a Storm Recovery Charge ("SRC") to recover major storm costs as a component of a proposed Distribution Adjustment Charge ("DAC") that was previously proposed as part of the COVID-19 cost recovery proceeding;[2]
- The results of Residential and Commercial & Industrial Electric Vehicle ("EV") Cost of Service Studies that were required by the CEF-EV Order.[3] As a result of these COSSs, the Company proposes the following:
    - A Residential Time of Use ("TOU") Program and associated Rate Schedules; and

[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order"), paragraph 25.

[2] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

[3] *I/M/O the Petition of Public Service Gas and Electric Co. for Approval of its Clean Energy Future – Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, B.P.U. Docket No. EO18101111, Decision and Order Approving Stipulation (January 27, 2021) ("CEF-EV Order").

- An optional Direct Current Fast Charge ("DCFC") Distribution kWh Charge to replace corresponding Distribution kW Charges for premises that solely serve DCFC charging facilities;

- Permit residential TOU rates (RLM or proposed RS-TOU) to serve residential EV charging at non-residential premises (such as a detached garage on a residential property);
- Changes to Streetlighting Rate Schedules, which makes Light Emitting Diode ("LED") luminaires the default offering and closes Non-LED luminaires for new installations; and
- Tax Adjustment Credit ("TAC") modifications.

I also sponsor the Company's proposed Tariff, which is attached to the Company's transmittal letter as Schedule 1.

SCHEDULE INDEX

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared and/or compiled by me or under my direction and supervision:

SCHEDULE DESCRIPTION	NUMBER
Qualifications of Stephen Swetz	SS-E1
Basis of Calculations Schedules	
Actual and Weather Normalized Billing Determinants	SS-E2
COSS Adjustments	SS-E3
Cost of Service Schedules	
Illustration of Cost Segmentation Methodology	SS-E4

Details of Complete Company COSS Study SS-E5
COSS Summary Report by Functional Segment SS-E6
COSS Revenue Requirements by Rate and Function SS-E7
Sync with Rate Design SS-E8
Rate and Rate Design Schedules
Inter Class Revenue Increase Allocations.....SS-E9
Service Charge Calculations SS-E10
Proof of Revenue by Rate Schedule SS-E11
Comparison of Typical Bills.....SS-E12
Staff's Cost Allocation Methodology Related Schedules
Details of Complete COSS Study – Staff's Method.....SS-E13
Summary Report – by Functional Segment – Staff's Method.....SS-E14
Functional Cost Summary – Staff's Method SS-E15
Service Charge Calculations – Staff's Method.....SS-E16
Tax Adjustment Credit (TAC) Schedules
TAC Revenue Requirement and Rate Calculations.....SS-TAC-1-6E
SRC Schedules
SRC Balance and Rate Calculations SS-SRC-1-3E
EV Cost of Service Studies Schedules
Residential Electric Vehicle COSS.....SS-EV-1
Commercial & Industrial Electric Vehicle COSSS SS-EV-2
CEF-EV Rate Adjustment Schedule.....SS-CEF-EV-1

OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSES

Overview

Q. What terminology does your direct testimony use regarding revenue and rates?

A. Throughout this testimony, the revenue or percentage increase for "Distribution" is based only on revenue from the Service Charge and the kilowatt-hour ("kWh") and per kilowatt ("kW") Distribution Charge(s) indicated in the particular rate schedule. The term "Delivery" refers to revenue from the Service Charge and Distribution Charges as indicated on the particular rate schedule, plus the revenue from all of the applicable adjustment clauses. The "Total Bill" equals the Delivery Charges plus electric supply, and is calculated as if all customers were supplied on Basic Generation Service ("BGS").

Q. Please describe the electric distribution services provided by the Company.

A. The Company provides electric distribution services under the following Rate Schedules:

(i) Rate Schedule RS is the Company's primary residential rate schedule;

(ii) Rate Schedule RHS is a closed service that was available to residential customers where electricity was the sole source of heating;

(iii) Rate Schedule RLM is a time of use rate available to residential customers;

(iv) Rate Schedule WH is a closed service that was available to premises with controlled water heating installations;

(v) Rate Schedule WHS is available for controlled water heating storage or for the electric heating elements of a water heating service connected to an active solar collection system;

(vi) Rate Schedule HS is a closed service that was available to permanently installed comfort building heating equipment;

(vii) Rate Schedule GLP is for general purposes at secondary distribution voltages;

(viii) Rate Schedule LPL is for general purposes at secondary voltages where the customer's measured peak demand exceeds 150 kW and also at primary distribution voltages;

(ix) Rate Schedule HTS is for general purposes at subtransmission, transmission and high voltages;

(x) Payment Schedule PEP is applicable to electricity produced from a Qualifying Facility as defined in the Public Utility Regulatory Policies Act of 1978 and delivered to the Company;

(xi) Rate Schedule BPL is service for dusk to dawn street lighting and area lighting to a body politic from Company-owned lighting facilities;

(xii) Rate Schedule BPL-POF is a closed service for dusk to dawn street lighting and area lighting to a body politic from publicly-owned lighting facilities; and

(xiii) Rate Schedule PSAL is service for dusk to dawn private street lighting and outdoor area lighting from Company-owned lighting facilities.

Q. Please provide an overview of the Company's filing in this proceeding.

A. As described more fully by Company witness Mr. Michael McFadden, PSE&G is seeking to increase its base distribution rates by approximately $522.1 million annually for its electric distribution business. Included in this filing, and as discussed further by Mr. McFadden and Company witness Mr. Cliff Pardo, the Company proposes to make certain modifications to the Company's TAC, including flowing back Mixed Service deductions to customers. This change will reduce electric rates by approximately $98.2 million annually. In addition, the Company is proposing the SRC to recover major storm costs, increasing rates by

approximately $38.0 million annually. My testimony provides support on how these changes will impact rates.

Residential Rate Affordability

Q. How have your Electric distribution rates changed since the 2018 base rate case?

A. The distribution component of a Residential Electric customer bill for a customer using 7,800 kWh per year has increased at a CAGR of 1.5%, well below the statewide comparable average of 5.0%. and below inflation levels. This modest increase is driven primarily by rate increases from the ES II Program to modernize the Company's electric system and to make it more reliable and resilient.

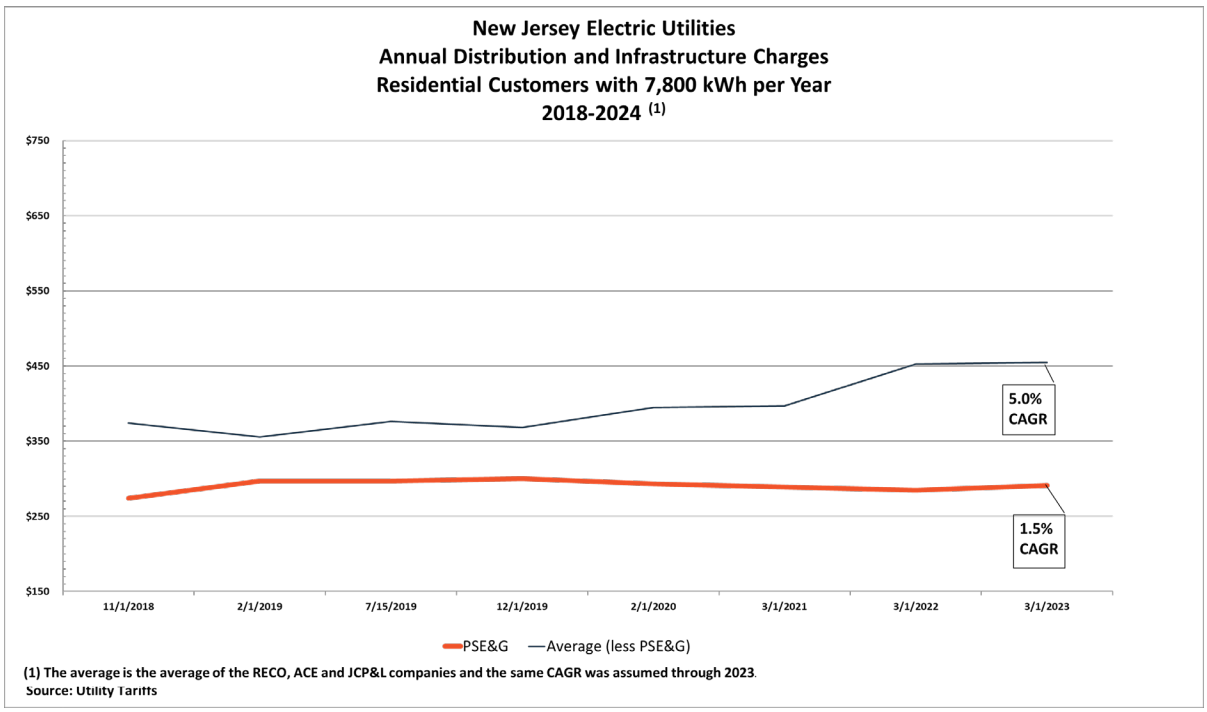


Figure 1

With respect to the Company's electric distribution rates, as can be seen in the chart, applying the State-wide average electric usage of 7,800 kWh per year for a typical residential customer to each utility (even though the average usage for PSE&G's typical residential customer is lower), the distribution portion of the bill for PSE&G, which is the subject of this

proceeding, is approximately $291 per year, the second lowest among the State electric utilities and lower than the $455 per year average of the other NJ electric utilities. Further, the Company's compound annual growth rate ("CAGR") of this cost since our last rate case is 1.5%, less than half of the average increase of other New Jersey utilities of approximately 5.0%.

Q. PSE&G's bills are lower on Distribution Charges, but how does PSE&G compare on a total bill basis?

A. PSE&G continues to be lower than the average compared to its peers. In NJ, PSE&G remains on the lower cost side compared to peers in terms of the total electric bill. As shown in Figure 2 below, PSE&G is almost 15% lower than the average.

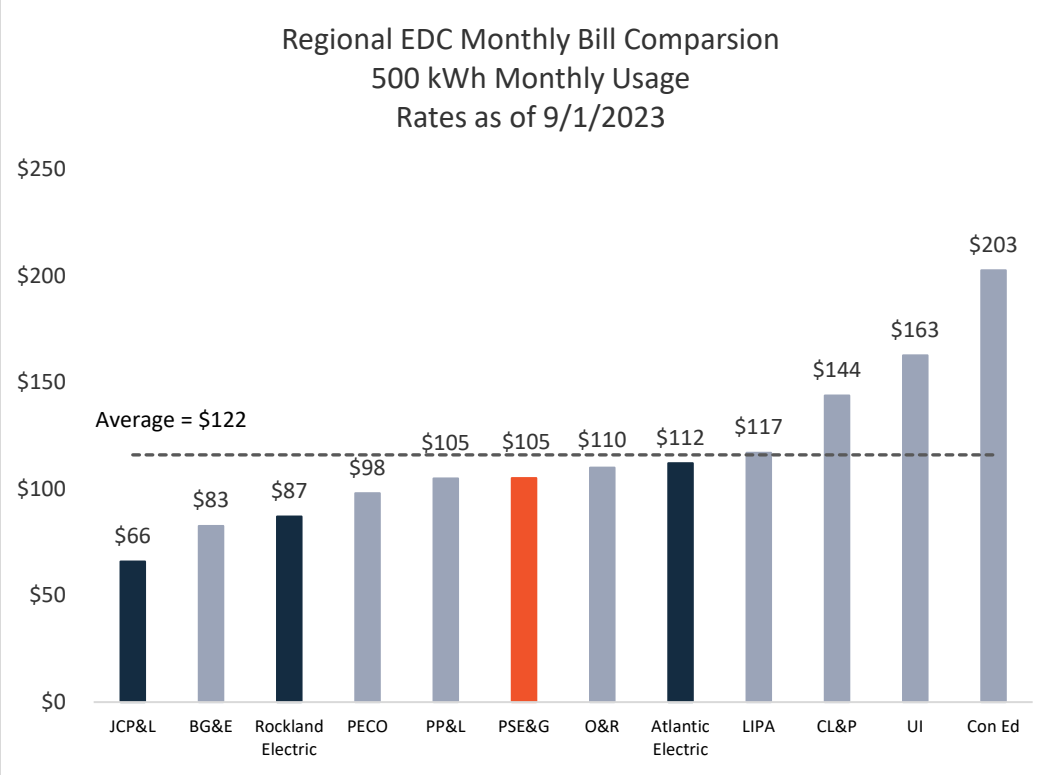


Figure 2

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, every other NJ electric utility has filed at least two base rate cases.

Q. Why has PSE&G not filed a rate case until now?

A. As discussed in more detail below, this is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently and be good stewards of the electric distribution system and the customer funds needed to operate and maintain it effectively. This is achieved by regularly benchmarking Company costs and employee performance and creating appropriate employee incentives to continue to improve upon historic success.

Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of our customer base. PSE&G's Energy Efficiency programs include incentives targeted to its lower income customers, with specific opportunities for both low and moderate income customers, who often face the highest energy burdens. The Company specifically seeks to provide energy savings opportunities to these customers in order to lower their energy burdens, as participants in the EE programs are expected to benefit from long term energy and bill savings, as well as health and safety improvements. The Company implements the State's Comfort Partners program to customers with incomes up to 250% of the Federal Poverty Level; that program provides free comprehensive energy savings solutions as well as upgrades to address health and safety problems in the home. PSE&G also recently filed its updated Clean Energy Future – Energy Efficiency II Program, which proposes to transfer administration of the Comfort Partners

program to the Company in order further reduce market confusion and streamline the process for lower-income customers to take advantage of energy efficiency programs;[4] PSE&G believes this change in administration of the Comfort Partners program will significantly improve customer access to energy efficiency and allow the Company more flexibility in serving the needs of lower-income customers. Also as part of the Clean Energy Future – Energy Efficiency II Program, PSE&G proposed to continue to target low and moderate income customers by providing comprehensive energy assessments and free direct install of energy efficient measures and services to income qualified households with higher incentives and opportunities for no-interest financing for health and safety improvements to these customers (the Comfort Partners program does not include financing, as all measures are paid for by the program and free to eligible customers), and to continue to provide enhanced opportunities for customers in overburdened communities. PSE&G also offers higher incentives for high efficiency heating and cooling systems and continues to provide financial incentives to both property owners and tenants to install high efficiency equipment in apartments and other multifamily properties. The Company promotes the use of these programs to our customers through bill inserts and community outreach, conducting this communication in multiple languages where possible and appropriate.

Q. Are there other assistance programs for lower-income customers outside of PSE&G's energy efficiency programs, and if so, please describe those programs and who is eligible.

A. The Company also advocates at the State and Federal level for various grants provided to lower-income customers, including the Low-Income Home Energy Assistance Program

[4] *I/M/O The Petition of Public Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency II (CEF-EE I) Program on A Regulated Basis*, BPU Docket No. QO23120874 (filed December 1, 2023).

("LIHEAP"), Lifeline and Tenants Lifeline Program ("Lifeline"), and the Universal Service Fund ("USF"). LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for their winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

PSE&G has more customers eligible for these low-income programs on a proportionate basis compared with other New Jersey utilities. This customer segment receives special focus.

Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors and conducted an external media campaign designed to provide customers opportunities to garner financial assistance and enter into deferred payment arrangements to avoid shut off.

Q. Has the Company considered the impact of electric rates on these customers?

A. Yes. As illustrated in Figure 3 below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009 and is essentially flat as compared with rates following the conclusion of the Company's 2018 base rate case.

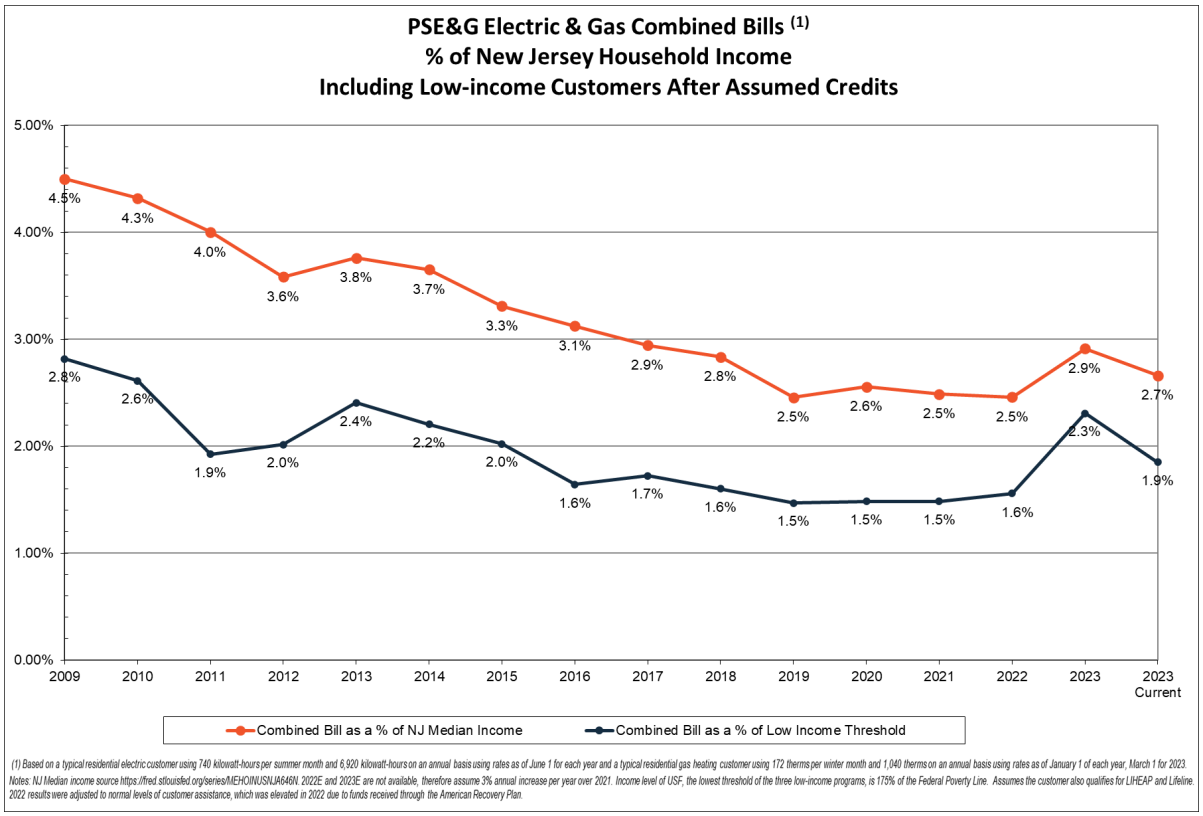


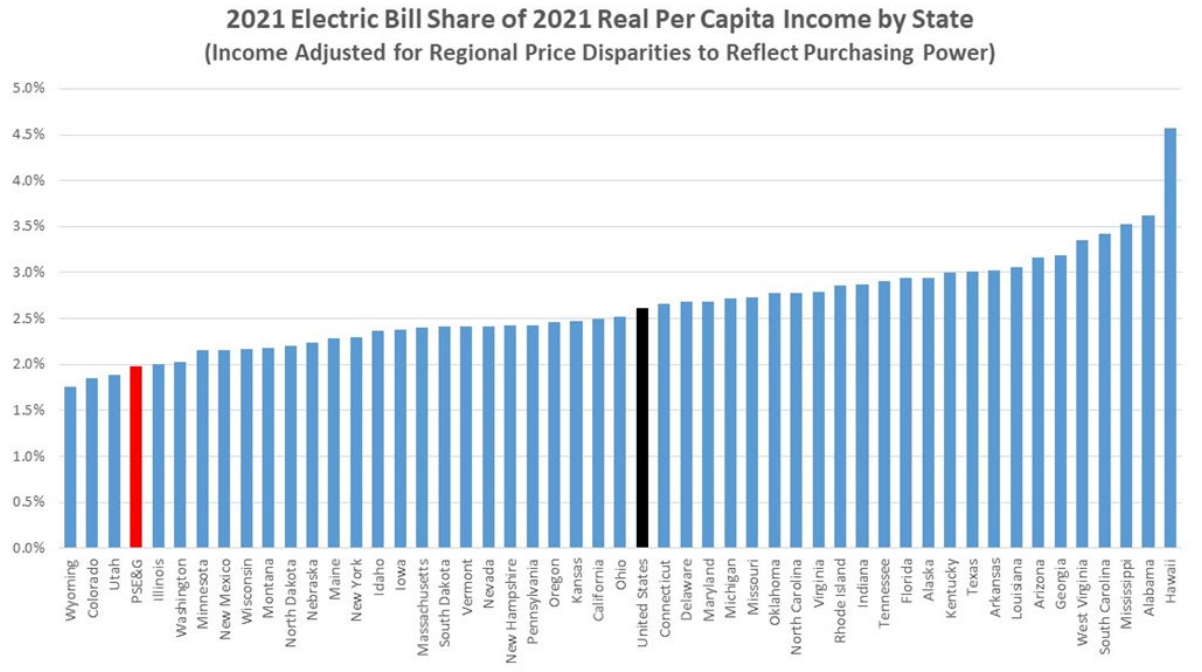
Figure 3

This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas

for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does this utility bill portion of overall income compare to other states?

A. Very well. As shown in Figure 4 below, PSE&G's residential electric bill as a percentage of per capita income for NJ is in the top quartile compared to the other states in the US. In other words, PSE&G's total bill represents less share of a customer's wallet than the relative utility bill share in most other states.



Source: U.S. Dept. of Commerce, Bureau of Economic Analysis, "Regional Data GDP and Personal Income", June 2023
U.S. Dept. of Energy , Energy Information Agency, "Sales (consumption, revenue, prices & customers", retrieved July 2023.

Figure 4

While PSE&G's bills as a percentage of overall NJ income is very favorable compared to most other states, the Company recognizes the current economic environment and the ongoing need to control costs. PSE&G has and will continue to control costs as much as possible to maintain affordable rates for customers without sacrificing reliability.

Q. How does the current RS Service Charge compare to other utilities?

A. As shown in Figure 5 below, PSE&G's monthly RS electric service charge is the second lowest compared to similar electric utilities in the region.

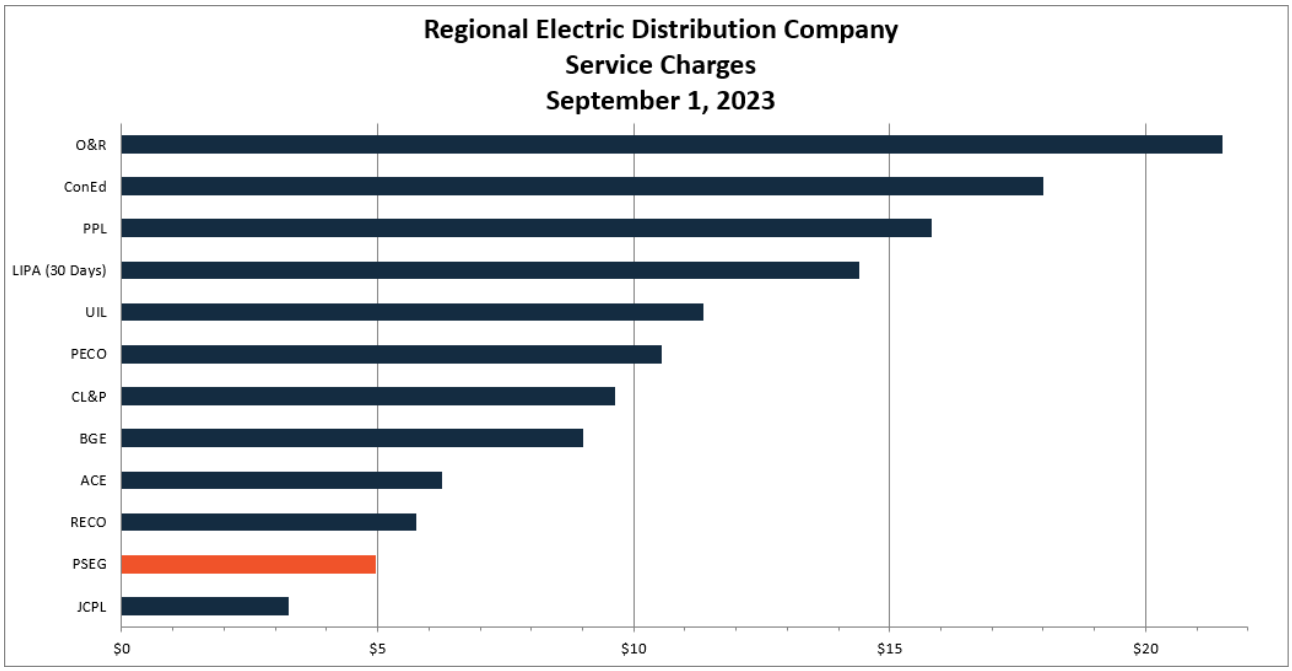


Figure 5

Q. What are the periods used for the COSSs and Rate Design that you are sponsoring in this proceeding?

A. The COSSs presented in this testimony are based upon the period January 1 to December 31, 2022. The only variations from actual costs in the COSS period were the requested overall Rate of Return value, proposed rate base adjustments such as working capital requirements, the proposed *pro forma* adjustments, and adjustments to synchronize the number of customers and usage used in the COSS to those used in the Company's rate design. These adjustments, along with the rate design presented in this testimony, are based upon the Test Year of June 1, 2023 through May 31, 2024 (hereafter "Test Year").

Q. What billing determinants will be used to determine the revenue requirement and rates that are being established in this proceeding?

A. The billing determinants used to establish rates and the revenue requirement allocation for each rate class in this proceeding will be the actual Test Year billing determinants as adjusted for normal weather. For the initial filing and any updates (prior to the final filing) with all actual data, the billing determinants will be a mix of weather normalized actual and forecasted billing determinants. Weather normalized billing determinants are calculated by adjusting actual recorded monthly electric sales to account for the effects of abnormal weather. A summary of the actual billing determinants, the weather normalized billing determinants, and the variation of each determinant from normal for the Test Year period is shown in Schedule SS-E2.

Weather Normalization of Billing Determinants

Q. What weather pattern is used to weather normalize actual billing determinants?

A. The Company utilizes a twenty-year weather pattern as measured at Newark Liberty International Airport covering the period ended December 31, 2021.

Scope of the Cost of Service Study

Q. Please describe the COSSs that the Company is presenting in this proceeding.

A. The Company is presenting two COSSs in this proceeding – its recommended COSS, referred to as the "Company COSS" – and an additional COSS based on a methodology developed by BPU Staff, referred to as the "Staff COSS." As discussed more fully below, the Company does not support the use of the Staff COSS to establish rates in this proceeding, but is submitting the study in compliance with the 2018 Rate Case Order. The COSSs discussed in this testimony are for the electric distribution portion of the Company's operations. Thus, the COSSs are generally "wires only" analyses for the regulated electric delivery business.

They do not include the costs for the Company's Transmission business, which is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), nor any electric production or supply costs. Although PSE&G remains responsible to provide BGS, the determination of rates charged to end-use customers for this service are addressed in other proceedings.

Adjustments to Accounting Data

Q. Did you make any adjustments to the accounting data used in the COSSs?

A. Several adjustments to the 2022 accounting data used in the COSSs were necessary prior to its use. These adjustments and the FERC Account associated with each of these adjustments are shown in Schedule SS-E3.

In the rate design process, the unit charges associated with these adjustments will be added back as appropriate in each rate schedule to assure full recovery of all expenses. The Company COSS and the Staff COSS each include these adjustments to costs and billing determinants.

COST OF SERVICE STUDY ("COSS") OVERVIEW

Introduction

Q. What is the first step in developing new electric rates?

A. The first step in developing new electric rates is the preparation of an appropriate COSS. The Company COSS was used to both separate costs by functional segments and to apportion (or allocate) these segmented costs to the rate classes or sub-classes based upon each class's responsibility for that cost.

Q. What is the objective of an COSS?

A. The objective of the COSS is to measure the cost responsibility of each rate/class and distribution function (functionalization).

Cost Allocation Concepts

Q. Please describe the cost allocation concepts used in the Company's COSS.

A. Inherent in any COSS is the allocation to rate classes of many costs which by their nature are difficult to relate precisely to cost causation. Cost causation describes the cause-and-effect relationship between customer requirements, load profiles, and usage characterization, and the costs incurred by the utility to serve those requirements. Experts will differ on the best way in which many costs should be allocated among customer classes. The key is to determine which approach makes the most sense in terms of best answering the question of what caused the cost, and then to apply the result in a reasoned, balanced manner. At all times, it is important to recognize that the COSS is intended to be a guide to appropriate ratemaking, and that one objective of ratemaking is that the end result should be a reasonable one.

The development of a COSS requires an understanding of the operating characteristics of the utility system. Electric distribution company facilities, such as substations, wires, and transformers, are planned and constructed to provide reliable service on a least-cost basis. distribution planners must design distribution systems with sufficient wire and transformation capacity to meet customers' peak loads while, of course, maintaining safety and reliability.

Each portion of the electric distribution system is nominally designed to carry the expected peak electric loads, without concern for the loadings in other hours or periods of the year. Although it is mathematically possible to develop an allocator of costs based upon virtually any attribute or formula, the use of a method that has little or no relation to the underlying cost causation is simply flawed. If the adopted approach reasonably tracks cost causation and the guidance is applied with a reasoned, balanced view, fair and equitable delivery rates to all classes of delivery customers will be the end result.

As I discuss later, I have used the results from the Company COSS as a guide in developing rates, but tempered the final rate design to provide a reasonable balance between the goal of moving each rate schedule towards costs and the goal of holding the increases to reasonable percentage increases based upon the resulting customer impacts.

General Cost Allocation and Functionalization Methodology

Q. What is the basis for the cost allocation and functionalization methodologies used in the Company COSS?

A. The Company COSS incorporates a method identical to that as used by the Company in its prior electric base case and is based on the concepts and theories recommended in Chapter 6 of the current NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") regarding the classification and allocation of electric distribution plant. Although much has changed in the industry since this document was published, the methodology presented is still valid and relevant to evaluating the costs for today's electric distribution business.

The NARUC Manual outlines the general methodology to be used on page 90 as follows:

> *When a utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demands requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.*

And later on that same page 90:

> *Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customer's on the utility's system…each primary plant account can be separately classified into a demand and customer component.*

The NARUC Manual then discusses the allocation of the demand related distribution costs on page 97 in the middle of the first paragraph:

The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have a much lower diversity. They are normally allocated according to the individual customer's maximum demands.

Q. What are the fundamentals of classifying and allocating the costs of providing distribution service that are described in the NARUC Manual?

A. The methodology presented in the NARUC Manual presents three key distribution Cost of Service fundamentals for classifying and allocating costs incurred to provide each customer distribution service:

1. Distribution costs have no energy related component
2. The load diversity as experienced by specific facilities or equipment determines the cost allocation method that should be used
3. Poles, conductors, line transformers, services, and meters have a customer component

Q. Please describe these three fundamentals and how they are used in the Company COSS.

A. The first fundamental, the absence of an energy related component, is very basic. With the limited exception of electrical losses, the amount of energy, as measured by kWh consumption, has no impact on the planning, design or installation of any electric distribution plant. Therefore, kWh consumption has not been included in the Company's methodology as the basis of allocation of distribution costs.

The second fundamental, load diversity as experienced by specific facilities or equipment, is somewhat subtle. Electric distribution facilities are designed based on various criteria depending upon the function of each particular piece of equipment.

On one extreme, a piece of equipment that connects a customer to the electric system (such as a service drop) is sized to handle the expected peak load of that customer, regardless

of when that peak load might occur. For example, for some residential customers this peak might be a hot summer night when they have their central air conditioner at full power, all the lights in the house are turned on, and the refrigerator is running. For other residential customers without many appliances, the peak might occur on Christmas morning when decorations are lit and the furnace fan on the gas heating unit turns on. Similar effects would be seen for all types of industrial and commercial customers as well, with the occurrence of the peak load varying, in effect, by customer.

On the other extreme, an electric distribution substation is designed to handle the peaks expected at that specific substation at the time of peak demand at that location. At these locations, a customer's peak demand, the number of customers served, or even kWh usage for any specific customer or any combination of customers, is immaterial. The only value that matters is the expected peak demand at that substation. For the Company's service territory, given the combined loads of customers, equipment installed, and the local climate, these peaks are customarily observed in the late afternoon of a hot summer day.

The effect of varying diversity is a continuum between these two extreme points of the electric distribution system. To determine the effects of such variations in load diversity between the substation and the service drop, or to develop a unique cost allocation methodology to account for each different type of diversity of load, would be a vast and impracticable task. In practice, any methodology used must strike a balance between one that is both theoretically ideal and one that can actually be implemented. The methodology presented in this testimony strikes this balance and is consistent with the underlying basis for the installation and design of the distribution system by the Company's distribution planners.

Q. Does the Company agree with the third fundamental identified by NARUC -- that certain facilities such as poles, conductors, line transformers, services, and meters have a customer component?

A. Yes. The Company agrees with the third key point identified in the NARUC Manual, that a portion of distribution facilities are customer related. However, due to the complexities and resources required to perform a study of the portion of facilities that should be classified as customer related, and the likelihood that such a study would show a need for increased residential charges that would far exceed what the Company is proposing in this proceeding, the Company has not undertaken a study to quantify this customer-related portion for this proceeding, but may do so in future rate cases.

Q. How is the PSE&G electric distribution system segmented or functionalized in the Company COSS?

A. As explained in more detail below, the Company COSS segments the electric distribution utility plant into six distinct segments – Access, Local Delivery, System Delivery, Street Lighting, Customer Service, and Measurement. Of these six segments, the Access, Local Delivery, and System Delivery segments are much larger than the other three and form the core of the distribution business.

Q. Please describe the Access, Local Delivery, and System Delivery segments in more detail and provide an overview of how you have allocated the costs of these segments.

A. The Access segment is limited to the electric service drop to individual customers; the Local Delivery segment is comprised of plant that is shared among a small number of customers, and the assets comprising the System Delivery segment serve a large number of customers. Consistent with the second and third NARUC fundamentals discussed above, I have allocated the Local Delivery costs based on the sum of customer individual peak

demands. This allocation follows the NARUC cost causation principle that facilities that are electrically close to customers are sized to carry the sum of undiversified customer peak loads.

Because System Delivery facilities are electrically farther from the customers, and see only highly diversified customer demands, I have allocated these facilities' costs solely on the basis of each rate class's contribution to the system peak, or what is termed each rate class's Coincident Peak ("CP"). The sum of customer peaks for Local Delivery costs and rate class CPs for System Delivery costs forms a reasonable basis for the allocation of costs to each rate class because they represent the underlying basis of the cost causation for the type of equipment that comprises each distinct segment.

Because subtransmission and primary circuits have characteristics partially consistent with Local Delivery and partially consistent with System Delivery assets, a cost separation methodology for allocating these costs was developed in consultation with the Company's distribution planners. For subtransmission circuits, the function of which is primarily to distribute power between substations and only secondarily to serve 26 kV customers (on Rate Schedule HTS-subtransmission), an analysis of the loads determined that a 21.1% - 78.9% spilt between the functions of Local Delivery and System Delivery was appropriate.

The function of primary circuits, however, was determined to be more evenly split between providing Local Delivery and System Delivery functions. A primary circuit carries power from a substation to customers who are typically served through transformers along its length. The portion nearest the substation connection has a highly diversified load because it carries the load attributed to all customers on that particular circuit. It thus performs a function similar to that of the substation, and thus could be considered primarily a System Delivery asset and should be largely allocated on the CP of the classes served. On the other extreme, the portion of the circuit that is electrically farthest away from the substation may serve only

one customer and must be designed to handle the peak demand of that specific customer, resulting in zero load diversity. It thus could be considered a Local Delivery asset and allocated on the sum of the customer peaks for the classes served. Along the length of the primary circuit, the diversity gradually shifts from the highly diversified load at one end to the undiversified load at the other end. As a result, I have utilized a 50% - 50% split between Local Delivery and System Delivery to segment and allocate all primary circuits' costs as a representation of the average diversity and dual functionality of this equipment.

The remaining segment, the Access segment, is allocated via a special study of the costs of service drops by rate class as discussed more fully below.

Functionalization of the Six Segments

Q. What is the first step in the process of performing an COSS?

A. As the first step in that process, the COSS unbundles total costs into the six distinct functional segments that I previously discussed – Access, Local Delivery, System Delivery, Street Lighting, Customer Service, and Measurement.

Q. Once these functional segments are developed, how are they used?

A. These separate functions (or segments) assist in the development of individual rate schedule components, such as the Service Charge. Once the plant and expenses are functionalized to the proper segment, the allocation process spreads the cost responsibility to the rate classes.

Q. What items are included in each of these segments?

A. The list below describes what is included in each of the six segments:

- The Access segment includes the plant and operation and maintenance ("O&M") costs related to the electric service drop.

- The Local Delivery segment includes all equipment (plant and O&M) related to the local distribution facilities.
- The System Delivery segment includes all equipment (plant and O&M) related to the "bulk" system distribution facilities.
- The Street Lighting segment is limited to the luminaires, brackets, and poles used only for street lighting purposes (the latter termed "street lighting poles").
- The Customer Service segment includes all costs relating to billing, inquiry, sales, service, and collection activity.
- The Measurement segment includes the costs for meter reading, meter plant, and meter O&M.

Q. Are all costs included in these six segments?

A. Yes, all costs are functionalized to one or more of these of six segments.

Access Segment

Q. Please discuss the Access segment in greater detail.

A. The Access segment is the initial link between the shared or common distribution system and the customer's own electric system, comprised of the electric service drop whose gross plant is recorded in FERC Account E369. Service drops are illustrated as a thick dashed line on Schedule SS-E4. The embedded costs for this segment are allocated across the rate classes based on an analysis of current unit costs, determined from typical service drop lengths and wire types as estimated by the Company's distribution planners. In situations where various size services are used to provide service to customers on the same rate schedule but with different peak loads, only the relative cost of the minimum size service is functionalized to this segment. The remainder is functionalized to the Local Delivery Segment for recovery

through kWh or kilowatt ("kW") charges and is not included in the costs to be recovered by Service Charges.

Local Delivery Segment

Q. Please discuss the Local Delivery segment in greater detail.

A. As discussed above, the Local Delivery facilities are the portions of the distribution system that are used to serve multiple customers and are also electrically and physically closest to the point of connection with individual customers' service drops. These facilities include the following types of plant:

- All secondary wire other than that used for customer service drops and for street lighting service,
- All line transformers; including all pole top units, pad mounts, underground, and network transformers,
- 21.1% of the Company's 26 Kilovolt ("kV") circuits - including poles, conductors and devices (only applicable to customers served at subtransmission voltages),
- 50% of the Company's primary circuits - including poles, conductors, and devices, and
- The portion of the service drop and meters in excess of the relative minimum amounts.

Although many customers share these facilities, the load carrying capacity of individual transformers, lines, and circuits is driven primarily by the sum of the undiversified peak demand of individual customers. Therefore, the majority of investment in the Local Delivery segment has been allocated to the rates based on the sum of the customers' individual peak demands.

As I have previously mentioned, although the Company agrees with NARUC that a portion of these facilities is customer-related and should be allocated based on the number of customers served, it is not proposing an allocation method based on this fundamental in this proceeding but may do so in future rate case proceedings. The outcome of such an allocation study would likely indicate that residential customers cause a higher proportion of costs than indicated by the methods used in preparing the Company COSS.

Investment in line transformers was allocated to the rate classes based on the average embedded costs, on a dollar per kVA basis, that were derived from a study that linked the actual transformer serving each customer with the Company's accounting records. This study is provided in the workpapers that support this testimony**.** Facilities related to the Local Delivery segment are illustrated as a thin solid line on Schedule SS-E4. A detailed discussion of the segmentation and allocation of each FERC Plant Account related to this segment is discussed in Appendix-E1.

System Delivery Segment

Q. Please discuss the System Delivery segment in greater detail.

A. The System Delivery segment is used for the portions of the distribution system that are planned to meet large, very diversified loads from many sizes, classes, and types of customers. Thus, this segment is composed of the portion of the distribution system facilities that is electrically farthest from individual customers and is sometimes referred to as the bulk distribution system. It is comprised of the following type of facilities:

- Switching stations and substations (the distribution portions only),
- 78.9% of the Company's 26 kV circuits - including poles, conductors, and devices, and

- 50% of the Company's primary circuits - including poles, conductors, and devices.

The costs for these System Delivery facilities are allocated across applicable rate classes based on the classes' contribution to the system CP, because the CP criteria is used as the planning criteria for this type of investment. Facilities relating to the System Delivery segment are illustrated as a thick solid line on Schedule SS-E4. As with the prior segment, a detailed plant-by-plant discussion of the segmentation and allocation is discussed in Appendix-E1.

Street Lighting Segment

Q. Please discuss the Street Lighting segment in greater detail.

A. This segment comprises the investment for street lighting luminaires, street lighting poles (poles used exclusively for street lighting), and other miscellaneous devices such as street lighting brackets and/or shrouds, and all associated O&M expenses for this equipment. Where a pole is used solely to provide street lighting, termed a "street lighting pole," one section of secondary wire was also segmented to this function for each pole so identified.

All investment and expenses in the Street Lighting segment were directly assigned to the three street lighting Rate Schedules of BPL, BPL-POF, and PSAL based upon the number and type of lights and poles billed under each rate schedule.

Customer Service Segment

Q. Please discuss the Customer Service segment in greater detail.

A. This segment encompasses all costs related to Customer Service type functions, such as costs related to billing, payment receipt and processing, collection activity, and other account maintenance type costs, with the exception of meter reading costs, which are included

in the Measurement segment. These costs are allocated to the rate classes based upon a separate study of Customer Service functions.

Measurement Segment

Q. Please discuss the Measurement segment in greater detail.

A. This segment includes costs for meter reading and the investment and O&M related to the meters themselves. Meter reading costs are allocated to the rate classes based upon a separate embedded cost analysis of Customer Service functions. Given that new Advanced Metering Infrastructure ("AMI") meters are relatively the same cost for customers in each rate class, the meter investment is allocated across the rates based upon the relative installed cost of new meters.

Modeling Procedures

Q. Please describe the COSS modeling procedures as well as how all COSS items are segmented and functionalized.

A. The COSS was developed based upon the weather normalized billing determinants and costs for each of the rate schedules for the COSS test period as defined above. The revenues received by each rate class were calculated (or target balanced) such that the resulting Rate of Return ("ROR") for each rate class equals the Company's proposed overall ROR. Schedule SS-E5 contains the complete details of these final COSS model results, Schedule SS-E6 presents a summary report of the revenue requirements by functional segment, while Schedule SS-E7 shows the revenue requirements by function (or segment) for each rate class.

The detailed description of how all COSS items are modeled, segmented, and functionalized is discussed in Appendix-E1. In Appendix-E1, a description is provided of how each of the major plant categories (gross plant) is segmented or functionalized. I then discuss the procedures used for Common and General plant, depreciation reserve, adjustments to rate

base, operating revenues, O&M expenses for utility plant, A&G expenses, depreciation and amortization expenses, pro forma expense adjustments, and finally, taxes.

Schedule SS-E5 shows the details of the COSS used to calculate distribution revenue requirements by rate schedule. This study was used in the development of the proposed rates. These results are summarized by revenue requirements for each rate schedule and by segment in Schedule SS-E6.

Q. Please summarize the results of the Company COSS.

A. Schedule SS-E5 shows the details of how each plant and expense item was separated into each of the six segments and allocated to each category of customers for each of the various rate classifications based upon the extent to which those groups of customers caused the costs, along with the results of the allocation for each plant and expense item. Schedule SS-E6 shows a high-level summary of expenses, plant, and revenue requirements for each of the six functional segments, while Schedule SS-E7 is a summary report of the rate related revenue requirement for each rate class in total.

The revenue requirements reported in Schedules SS-E5, SS-E6 and SS-E7 do not include the costs or revenue requirements associated with adjustment clauses and New Jersey Sales and Use Tax ("SUT"). These costs, however, will be collected from customers directly through the appropriate charges, as I will discuss in the Rate Design portion of this testimony.

Synchronizing the Cost of Service Study to the Rate Design

Q. Please explain how the Company COSS was synchronized with the proposed rate design.

A. As previously noted, the Company COSS is based on the period of January 1, 2022 through December 31, 2022, while the rate design is based on the Test Year of June 1, 2023 through May 31, 2024. It is not possible to use the COSS results directly in the rate design

process because the number of customers, kilowatt-hours delivered, as well as plant and expenses are slightly different between these two time periods. To properly execute the rate design process, the Company COSS results must be adjusted slightly to correspond to the rate design test year period. The methodology used to synchronize the COSS results is included in Schedule SS-E8. Because the primary difference is in the number of customers and amount of energy delivered, each functional segment's revenue requirement from Schedule SS-E7 was multiplied by the ratio of either the number of customers or kilowatt-hours delivered for the rate design test year to the value during the COSS year. The development of these sync factors is shown on page 1 of Schedule SS-E8. The revenue requirements associated with the Street Lighting Segment (Col 1), Local Delivery Segment (Col 3), and the System Delivery Segment (Col 4) were adjusted by the ratio of the kWh delivered in these two periods. The revenue requirements associated with the Access Segment (Col 2), Customer Service Segment (Col 5) and the Measurement Segment (Col 6) were adjusted by the ratio of the number of customers in these two periods, except for rate classes BPL, BPL-POF, and PSAL, which were adjusted by the kWh sync factor described above for all functional segments. These steps are shown on lines 1 to 15 of page 2 of Schedule SS-E8. The resulting adjusted COSS functionalized revenue requirements are each then adjusted on an equal percentage basis so that the total equals the proposed revenue requirements, as set forth on lines 21 to 35 of page 2 of Schedule SS-E8. It is these final adjusted functionalized revenue requirements that are used in the rate design process.

RATE DESIGN

Introduction

Q. What are your objectives for developing proposed electric rates?

A. The proposed electric rates have been developed to meet several objectives. The primary purpose is to provide recovery of revenues equal to the amount of the proposed revenue requirement. Additionally, this recovery should be effectuated on an equitable basis that provides correct price signals to individual customers based on the cost to serve those customers. The final objective is that rates should be simple and understandable for the customer.

Q. Why is it important to send correct price signals to individual customers based upon the cost to serve those customers?

A. I cannot overemphasize the need for development and implementation of correct price signals to customers. Distribution pricing must follow the underlying demand-based cost causation. Rates designed following this methodology will be equitable and will provide the ability for appropriate demand response from customers who are able to change usage patterns to achieve economic savings as a result of the price signals provided.

Q. What determines the cost to serve customers?

A. The Company COSS presents an allocation among customer groups of the embedded costs to provide regulated utility services and determines the cost to serve customers.

Q. Are the proposed new rates based solely on the results of the Company COSS?

A. No. The COSS is a guide to appropriate ratemaking; its results are not applied in a strict mathematical manner to design proposed rates. While the goal is to move rates toward a full cost basis, the achievement of that goal must be balanced against the need to achieve reasonable end results as I discuss more fully below.

Q. Do the rates included in your testimony include or exclude New Jersey SUT?

A. The proposed rates discussed in the next sections of my testimony and associated Schedules exclude SUT unless specifically indicated. However, the appropriate prices both without and with SUT are included in the Proof of Revenue by Rate Schedule in Schedule SS-E11 as well as the proposed Tariff Sheets set forth in Schedule 1 of the transmittal letter, and all other schedules that reference rates charged to customers.

Limitations on Rate Changes

Q. Did you apply limits in designing proposed rates in this proceeding, and, if so, why?

A. Yes. To achieve an overall goal of designing just and reasonable rates, I applied the principle of "gradualism" to temper the rate increases indicated by the results of the Company COSS. To apply the principle of gradualism, I employed a number of limits on the size of the rate increases that are proposed.

Q. Please describe the rate increase limits used in developing the proposed electric rates.

A. The first limit is that the proposed overall percentage revenue increase will be shared among all customer classes. Although a primary goal is to move the distribution rates for each rate class toward costs as indicated by the Company COSS, no class will receive less than 50%, nor more than 125% of the overall average distribution percentage increase. In addition, no class will receive more than 150% of the overall average percentage bill increase. These rate increase limits were selected to provide a reasonable balance between the goal of moving towards costs, and the need to achieve equity among customers. The calculation and percentage values of these limits are shown on page 1 of Schedule SS-E9.

Q. Are there any exceptions to the proposed limits?

A. Yes. Much of the revenue requirement increase has been driven by grid investments that are unrelated to BPL and PSAL luminaries and poles. BPL luminaires and poles current distribution revenue is nearly at its cost to serve, therefore the proposed minimum distribution revenue percentage increase was lowered from 19.742% to 10%. The proposed distribution revenue percentage increase for PSAL luminaires is 20.607%, which increases its revenue almost equal to its cost to serve.

Inter Class Revenue Increase Allocations

Q. Please describe the process for allocating the proposed distribution increase to each rate class.

A. Page 1 of Schedule SS-E9 shows the calculation of the overall average percentage increase for distribution and total electric bills, as well as the calculation of the upper and lower limits to be used in the inter class revenue increase allocation on Schedule SS-E9, page 2.

Page 2 of Schedule SS-E9 shows the proposed inter-class allocation of the revenue increase. The Rate Schedules are indicated in Column 1, while Column 2 is the Proposed Distribution Revenue Requirement based upon the Company COSS results that were synchronized to the rate design test year. Column 3 is the Present Distribution Revenue, while Column 4 shows the increase that would occur if the synchronized Company COSS results were used directly – hence the use of the word "Unlimited" in the column heading. Column 5 is the present total electric bill calculated as if all customers were supplied at BGS rates. Column 6 is the percentage increase in distribution if the unlimited increase in dollars (from Column 4) were applied to the rates; that is, the percentage increase to each rate schedule if these COSS based increases were applied without constraints. The result of the proposed allocation of the Company's revenue requirement increase to the rate classes, consistent with

the principles outlined in the previous section, Limitations on Rate Changes, is presented in Column 7 and Column 9. Specifically, Column 7 shows the percentage increase and Column 9 shows the Proposed Distribution Revenue Increase by Rate Class. Column 8 shows the proposed total bill percentage increase if all customers were supplied at BGS rates.

The final step was to calculate the proposed distribution revenue increases for all rates other than Rate Schedules BPL and PSAL. These calculations and the application of the limits were performed in an Excel spreadsheet utilizing the "Goal Seek" function to both meet all of the requirements of the limits and properly allocate any revenue shortfall between the rates, while recovering the full requested increase in distribution revenue.

Page 3 of Schedule SS-E9 continues the proposed inter-class allocation from page 2. Column 2 carries over the Proposed Distribution Revenue Increase from Column 9 of page 2 and adds on the revenue impacts of TAC (from Column 3) and the proposed DAC (from Column 4). Column 5 shows the resulting net distribution revenue increase including TAC and DAC, while Column 6 shows the proposed total bill percentage increase if all customers were supplied at BGS rates.

Q. How should the rate design be affected if the Board approves an amount other than the Company's overall revenue increase request?

A. If the Board approves an amount other than the Company's overall revenue increase request, the increase to each of the classes should be allocated in proportion to the proposed distribution revenue increase shown in Column 9 of Schedule SS-E9, page 2.

General Rate Design Principles and Methodology

Q. Please describe the general rate design principles and methodology used in developing the proposed electric rates.

A. The rate design methodology presented in this testimony follows the philosophy of the cost allocation methodology used in the Company COSS in order to align, as closely as

practicable, the rates (prices charged to customers) with the underlying costs of serving those customers. This is a key element in the Company's rate design and its importance cannot be overstated. The rate design process is not just to recover the proper amount of revenue from each class, but, to the extent practicable, from individual customers as well, thereby preventing the subsidization of one customer by another. An appropriate rate design will provide correct price signals that reflect how customers' individual facilities impact the costs of the electric distribution system. Only by giving due recognition to what it costs to serve customers can the customers make the correct economic decisions.

The Service Charges for all rates that have service charges were set to move towards the sum of the revenue requirements indicated in the Company COSS for the Customer Service, Measurement and Access segments. With the exception of Rate Schedule RS and RHS, the change in these Service Charges were limited to the same general inter rate class limits of no more than 150% of the overall average distribution percentage increase. The proposed Service Charge change for Rate Schedules RS and RHS will be discussed later in my testimony.

These limits were selected to provide a reasonable balance between the goal of moving each rate component toward costs, and the goal of avoiding unreasonable bill impacts. Any shortfall in Service Charge revenue resulting from these limits was transferred to the remaining Local Delivery based charges of the particular rate schedule. These calculations are as shown in Schedule SS-E10.

The Distribution Charges for each rate class were set, subject to the limits on the percentage change previously discussed, to recover all the revenue requirements of the Local and System Delivery segments plus any shortfall created from limitations on the proposed Service Charges. The specific unit rate charges (the per kWh or per kW charge) in each rate

class are designed to recover the revenue requirements of the Local Delivery segment from annual billing determinants, while the revenue requirements for System Delivery are designed to be recovered only through summer billing determinants. Because the Company's system peak has consistently occurred during the summer period, the summer kWh is the best billing determinant to send the price signal to the customer that is most closely aligned with cost causation. For example, for a rate designed only around non-blocked kWh charges, such as Rate Schedule HS, the winter charge per kWh is the Local Delivery segment revenue requirement divided by the annual kWh use (the annual billing determinant). The summer charge per kWh is the System Delivery segment revenue requirement divided by the summer kWh use (the summer billing determinant), plus the Local Delivery segment revenue requirement divided by the annual kWh use (the annual billing determinant).

For the demand Rate Schedules GLP, LPL and HTS, the Company is proposing to continue two separate demand charges as currently applied. The first, the Annual Demand Charge, is a charge per kW for the monthly maximum kW that will be applicable in every month and is based on each rate class's portion of the Local Delivery segment costs divided by the sum of the customers' monthly peak demands. For Rate Schedule GLP, these applicable demands are the customer's monthly measured peak demands over the entire year. For Rate Schedule LPL-Secondary ("LPL-S") and LPL-Primary ("LPL-P"), these applicable demands are the customer's monthly measured peak demands occurring during any time period over the entire year. For Rate Schedule HTS-Subtransmission ("HTS-S") and HTS-High Voltage ("HTS-HV"), the applicable demands are the customers' single highest demand that occurs at any time during the entire year, also referred to as a "ratcheted demand."

The second demand charge, the Summer Demand Charge, is a charge per kW of the monthly peak demand but is only applicable in the four summer billing months – June through

September. This charge is based on each rate schedule's share of the System Delivery segment cost divided by the appropriate kW peak demands for the summer period only. For Rate Schedule GLP, these applicable demands are the customers' monthly peak demands for the summer billing months only (June to September billing months). For Rate Schedules LPL-S, LPL-P, and HTS-S, these applicable demands are the customers' monthly peak demands occurring during the on-peak periods in the four summer billing months.

The recovery of distribution revenue requirements through demand charges for those rate classes that are assessed demand charges is consistent with the Company's historical and current rate structure. Put into the context of the total electric bill for the average customer based upon annualized weather normalized rates, the portion of revenue that is collected through distribution demand charges remains small and ranges from approximately 17% for Rate Schedule GLP to 5% for Rate Schedule HTS-HV.

The limits for the changes in charges for individual luminaires and poles under Rate Schedules BPL, BPL-POF and PSAL will be discussed later in the discussion on the specific changes made to these Rate Schedules.

RATE SCHEDULE SPECIFIC CHANGES

Rate Schedule Residential Service ("RS")

Q. Please describe the rate design for Rate Schedule RS.

A. The rate design for Rate Schedule RS is shown starting on page 4 of Schedule SS-E11. The current rate is comprised of a monthly Service Charge, plus distribution charges based on monthly kWh use, with the charges differentiated using a two-block rate structure in the summer period.

As indicated in Schedule SS-E10 - Service Charge Calculations, (line 2), the Company COSS indicates that a significant increase in the monthly Service Charge is warranted. Consistent with the principle of cost causation, balanced by the principle of gradualism, the Company proposes that the Service Charge be increased by 1.5 times the average distribution increase to move the service charge closer to actual cost. The present kWh charges are blocked at 600 kWh per month. The winter rates are identical for both blocks, whereas the summer rates have an inclining block rate, where the second block (for usage greater than 600 kWh per month) is $0.003821 per kWh greater than the rate for the first block.

As previously described, the Company COSS results indicate that the summer charges should be greater than the winter charges because System Delivery revenue requirements should be recovered through summer kWh charges and Local Delivery revenue requirements should be recovered over the entire year. In the Company's previous base rate case, the summer kWh charges were set at an inclining block rate structure whereby the second block was $0.003821 per kWh (without SUT) higher than the first block. There is no underlying cost basis for an inclining block rate structure for the recovery of distribution costs. In fact, analysis based on load profile data shows that higher use customers have a higher load factor which would support a lower per kWh charge for the second block or a "declining block" rate structure. Despite the evidence that supports a declining block rate structure, consistent with the principle of gradualism, the Company proposes to keep the first and second blocks the same and not request a declining block rate structure.

Even with the proposed revenue increase, the proposed RS rate class revenue is significantly below cost. In addition, the current Summer Distribution kWh Charge is significantly lower than the cost to serve while the Winter Distribution kWh Charge is somewhat higher than the cost to serve. Therefore, the Company is proposing to adjust both

summer and winter Distribution kWh rates, so that each kWh rate will be an equivalent percentage below cost. As a result, the remaining distribution revenue increase for RS from page 2 of Schedule SS-E9, less the Service Charge revenue increase, will be recovered through the Summer Distribution kWh Charge.

The results of the Rate Schedule RS rate design appear on page 5 of the Proof of Revenue in Schedule SS-E11. The general format of the calculations is described on the first page of that Schedule. The calculation of the annual electric supply cost utilized in the Proof of Revenue for this and all other rate schedules is based upon all customers purchasing electricity on the appropriate BGS service. The magnitude of the BGS values remain constant in both sides in the Proof of Revenue (Schedule SS-E11) and their inclusion allows the proposed rate changes to be viewed in the context of a customer's overall bill.

Typical Rate Schedule RS customer bill impacts resulting from these changes are shown on pages 1-3 of Schedule SS-E12.

Rate Schedule Residential Heating Service ("RHS")

Q. Please describe the rate design for Rate Schedule RHS.

A. The rate design for Rate Schedule RHS is shown starting on page 6 of Schedule SS-E11. In general, the structure of Distribution Charges for customers on RHS remains the same as it is currently. The rate is comprised of a monthly Service Charge, plus distribution charges based on monthly kWh use, with the charges continuing to be differentiated using a two-block configuration in the summer and winter periods. This Rate Schedule remains closed, grandfathered to specific customers as it has been since January 1993.

As indicated on Schedule SS-E10 Service Charge Calculations, (line 3), the direct use of the Company COSS revenue requirements would indicate that a significant increase in the monthly Service Charge is warranted. In the past, the Service Charge for Rate Schedule RHS

has been set equal to the Service Charge for Rate Schedule RS. Consistent with the principle of cost causation, the Company proposes to maintain this relationship such that the Service Charge would be increased by an amount equal to the treatment proposed in the Rate Schedule RS Service Class

The kilowatt-hour charges are presently blocked at 600 kWh per month, with a declining rate structure block in the winter and an inclining block rate structure in the summer. The Proposed Distribution Revenue for RHS from page 2 of Schedule SS-E9 less the Service Charge revenue was designed to be recovered through the Distribution kWh charges. This remaining balance of revenue requirement was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance of revenue was divided by the sum of the total annual kWh for all usage. The proposed Winter Distribution Charges were designed to maintain the current declining block differential of ($0.017600). The Summer Distribution Charges were designed to recover both the System Delivery portion of the remaining balance of revenue and the summer portion of the Local Delivery revenue. The Company is proposing to set identical rates for both summer blocks, thus eliminating the inclining block rate structure. As is the case with the RS rate class, there is no underlying cost basis for an inclining block rate structure for the recovery of summer distribution costs. In fact, an analysis based on load profile data shows that higher use customers also have a higher load factor based on their individual customer peaks, which would support a declining block rate structure for higher use customers. Consistent with the principle of gradualism, the Company proposes to keep the first and second blocks the same.

Typical Rate Schedule RHS customer bill impacts as a result of these changes are shown on page 4 of Schedule SS-E12.

Rate Schedule Residential Load Management Service ("RLM")

Q. Please describe the rate design for Rate Schedule RLM.

A. The Company is proposing to close Rate Schedule RLM to new customers when the proposed Residential TOU Pilot Program becomes available to customers. The current rate design for the Rate Schedule RLM is shown starting on page 8 of Schedule SS-E11. The structure of distribution charges for customers on Rate Schedule RLM remains similar to what it is currently. The rate is comprised of a monthly Service Charge, plus time differentiated charges based solely on total monthly kWh use in each of two time periods. The Company COSS indicated that a small decrease in the Service Charge was warranted for this Rate Schedule. Applying the limits I discussed previously, the Company is proposing to maintain the current Service Charge.

The Proposed Distribution Revenue for Rate Schedule RLM from page 2 of Schedule SS-E9 less the Service Charge revenue was designed to be recovered through the Distribution kWh charges. This remaining balance was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance was divided by the sum of the total annual kWh for all usage. The System Delivery portion is proposed to be recovered during the Summer On-Peak period only, consistent with the methodology detailed earlier.

Typical Rate Schedule RLM customer bill impacts as a result of these changes are shown on page 6 of Schedule SS-E12.

Rate Schedule Water Heating Service ("WH")

Q. Please describe the rate design for Rate Schedule WH.

A. The rate design for Rate Schedule WH is shown starting on page 10 of Schedule SS-E11. This Rate Schedule also remains closed and is grandfathered to specific premises, as it has been since October 1980.

There currently is no Service Charge for service under this rate schedule and none is proposed. The unit charge has been set equal to the Proposed Distribution Revenue for Rate Schedule WH from page 2 of Schedule SS-E9 divided by the total billed kWh.

Rate Schedule Water Heating Storage Service ("WHS")

Q. Please describe the rate design for Rate Schedule WHS.

A. The rate design for Rate Schedule WHS is shown starting on page 12 of Schedule SS-E11. The Company is proposing no change in the structure of Distribution Charges for this Rate Schedule. The rate comprises a monthly Service Charge plus non-differentiated distribution charges based solely on monthly kWh use.

As indicated in Schedule SS-E10 Service Charge Calculations, (line 6), the Company COSS indicates that a significant increase in the monthly Service Charge is warranted. The Company, however, proposes that the Service Charge should only be increased consistent with the limits discussed previously. The charge was not moved closer to actual costs in order to minimize the percentage increase in the total bill for customers with very small usage.

The Proposed Distribution Revenue for Rate Schedule WHS from page 2 of Schedule SS-E9, less the Service Charge revenue, was designed to be recovered through the Distribution kWh charges.

Rate Schedule Building Heating Service ("HS")

Q. Please describe the rate design for Rate Schedule HS.

A. The rate design for Rate Schedule HS is shown starting on page 14 of Schedule SS-E11. This Rate Schedule is presently closed and is grandfathered to premises receiving service as of August 1, 2003.

As indicated in Schedule SS-E10 Service Charge Calculations, (line 7), the Company COSS indicates that an increase in the monthly Service Charge is warranted. The Company proposes however that the Service Charge should only be increased consistent with the limits previously discussed. The charge was not moved closer to actual costs in order to minimize the percentage increase in the total bill for customers with very small usage.

The summer/winter price differential follows the kWh-only rate price philosophy as previously discussed. The Proposed Distribution Revenue for Rate Schedule HS from page 2 of Schedule SS-E9, less the Service Charge revenue, was designed to be recovered through the Distribution kWh charges. This remaining balance was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Local Delivery portion of the remaining balance was divided by the sum of the total annual kWh for all usage. The System Delivery portion is recovered through the summer period Distribution kWh charges only.

Rate Schedule General Lighting And Power Service ("GLP")

Q. Please describe the rate design for Rate Schedule GLP.

A. The rate design for Rate Schedule GLP is shown starting on page 16 of Schedule SS-E11. The Service Charge has generally been set based on the per customer revenue requirements for the Access, Customer Service and Measurement segments and increased in accordance with the limits previously discussed. The Service Charge for unmetered accounts

was set based on the per customer revenue requirements for the Access and Customer Service segments because this sub-class has no meters or meter reading expenses. The Service Charge for Rate Schedule GLP-Night Use was set equal to the standard GLP Service Charge. Previously, the GLP Night Use Service Charge was set equal to the Rate Schedule LPL-Secondary Service Charge because previous generation interval meters were required. With the implementation of the advanced metering infrastructure project, the standard GLP meter will be able to provide the interval data to bill the Night Use Provision. These calculations are shown on lines 11-14 of Schedule SS-E10.

The proposed Distribution Revenues for Rate Schedule GLP from page 2 of Schedule SS-E9, less the Service Charge revenue, are designed to be recovered through the Distribution kW and kWh Charges. The current relationship in the recovery of Distribution costs between kW and kWh charges is being maintained in the proposed rate design. The amount allocated to be recovered through kWh charges was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS.

The amount allocated to be recovered through kW charges was apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS. The Annual Peak Demand charge was calculated as the Local Delivery segment costs divided by the sum of the Rate Schedule GLP customers' billed Monthly Peak Demands.

The second demand charge, termed the Summer Demand Charge, is calculated as the System Delivery segment cost divided by the sum of the Rate Schedule GLP customers' billed Monthly Peak Demands for the four summer months, June through September.

The Company proposes to retain the provision for unmetered Police, Recall or Fire Alarm Service with all charges increased at the average Rate Schedule GLP distribution percentage increase.

Typical Rate Schedule GLP customer bill impacts as a result of these changes are shown on pages 8 and 9 of Schedule SS-E12.

Q. What other changes are you proposing to Rate Schedule GLP?

A. To correct an issue from the rate design approved in the 2018 Rate Case Order, the Company proposes to adjust the current GLP rates to rates that would have been in place as intended in 2018. From this new baseline, the proposed rate adjustments based on proposed revenue requirements can be calculated. The prior rate design inverted the intended distribution kWh Summer and Winter rates, and the implemented kWh Winter rate was lower than intended.

Rate Schedule Large Power And Lighting Service ("LPL")

Q. Please describe the rate design for Rate Schedule LPL.

A. The rate designs for Rate Schedules LPL-Secondary and LPL-Primary are shown starting on pages 20 and 24, respectively, of Schedule SS-E11.

The Service Charge has been set based on the per customer revenue requirements for the Access, Customer Service and Measurement segments and is shown in Schedule SS-E10 and increased in accordance with the limits previously discussed.

The Company proposes to continue the current provision that provides a reduced Service Charge for the closed provision for grandfathered LPL-Primary customers expected to have a peak demand of less than 100 kW. The Service Charge for this sub-class has been set based on the sum of the per customer revenue requirements for the Rate Schedule GLP Access

segment, Rate Schedule GLP Customer Service segment, and the Rate Schedule LPL-Primary Measurement segment, subject to the limits I discussed earlier.

The Proposed Distribution Revenues from LPL-Secondary and LPL-Primary service as set forth on page 2 of Schedule SS-E9, less the applicable Service Charge revenues, were designed to be recovered through the Distribution kilowatt charges. These remaining balances were apportioned between Local Delivery and System Delivery based on the revenue requirements for these segments from the Company COSS.

The Annual Peak Demand charge was calculated equal to the Local Delivery segment costs from the Company COSS divided by the sum of the LPL customers' billed Monthly Peak Demands that occur at any time during each month.

The second demand charge, termed the Summer Demand Charge, is calculated by dividing the System Delivery segment cost by the appropriate sum of the On-Peak Monthly Peak Demands for the four summer months, June through September.

Typical Rate Schedule LPL customer bill impacts as a result of these changes are shown on pages 12 and 14 of Schedule SS-E12.

Rate Schedule High Tension Service ("HTS")

Q. Please describe the proposed rate design for Rate Schedule HTS.

A. The rate design for Rate Schedules HTS-Subtransmission and HTS- High Voltage are shown starting on pages 28 and 32, respectively, of Schedule SS-E11.

The Service Charges and kW demand charges have been calculated and are proposed to apply on a similar basis for Rate HTS-Subtransmission and Rate HTS-High Voltage and Rate Schedule LPL. The only slight difference is that because customers on Rate Schedule HTS-High Voltage are served directly from transmission facilities, there are no System

Delivery revenue requirements, and thus there is no Summer Demand Charge necessary for Rate Schedule HTS.

Typical Rate Schedule HTS-S customer bill impacts as a result of these changes are shown on page 16 of Schedule SS-E12.

Payment Schedule Purchased Electric Power ("PEP")

Q. Is the Company proposing a change to Payment Schedule PEP?

A. The Company is proposing no changes to the Payment Schedule PEP.

ELECTRIC VEHICLE ("EV") COST OF SERVICE STUDIES ("COSS")

Residential Study

Q. Please describe how the Residential EV COSS was developed.

A. The residential electric vehicle ("Res-EV") COSS was developed using 12 months of electric vehicle charger data from August 1, 2022 through July 31, 2023. This period was utilized in place of the 2022 calendar year cost of service test year as the data was readily available and allowed for the largest sample size of customers with a full year of charging data.

The data was collected in 15-minute increments with each increment consisting of total kWh usage, average kW demand, and peak kW demand. Each increment was summed to hourly data, by customer and date. The final data set included data from 826 residential EV charging customers.

From this set of data, the sum of the individual customer peaks was totaled, as well as the coincident peak usage that occurred during the Company system peak that occurred Tuesday, August 9, 2022 from 4-5pm. Sum of peak data was used to determine the EV customer contribution to Local Delivery costs and Coincident Peak data was used to determine

the respective contribution to System Delivery Costs. From here, ratios were calculated to the total RS rate class Local Delivery and System Delivery functions.

Q. What were the results of the study?

A. Based on COSS results, the RS Local Delivery costs are equal to $470,258234 with a Res-EV Sum of Peaks ratio of 16,651 kW / 11,830,661 kW = 0.1407% or $661,857. Similarly, the total RS System Delivery costs are equal to $300,953,037 with a Res-EV Coincident Peak ratio of 34 kW / 4,362,852 kW = 0.0008% or $2,348 for a total Res-EV Local and System Delivery revenue requirement of $664,204. Over the year of usage, total Res-EV energy usage equaled 2,921,627 kWh, resulting in a COS energy rate of $0.227341per kWh, which is significantly above the proposed class average RS Rate Schedules Distribution kWh rate of approximately $0.058523 per kWh.

Q. Based on these results, are you proposing alternative rates for Residential EV charging?

A. Yes. As part of the proceeding, the Company is proposing a Residential TOU Program, which will offer off-peak rates that are significantly lower than current RS or RLM off-peak rates. Details on this Program are described further below in my testimony.

<u>Commercial & Industrial ("C&I") EV COSS</u>

Q. Please describe how the C&I EV COSS was developed.

A. The C&I EV COSS was performed in a similar matter to the Residential EV COSS, with the only exception being the date range and source of the data. C&I data consisted of data from July 1, 2022 through June 30, 2023 from 34 DCFC customers.

Based on COSS results, the LPL-S Local Delivery costs are equal to $102,876,070 with an DCFC-EV Sum of Peaks ratio of 17,678 kW / 2,893,512 kW = 0.6110% or $628,538. Similarly, the total LPL-S System Delivery costs are equal to $126,845,827 with a DCFC

Coincident Peak ratio of 6,187 kW / 1,946,767 kW = 0.3178% or $403,125 for a total DCFC Local and System Delivery revenue requirement of $1,031,663. Over the year of usage, total DCFC kWh equaled 30,361,295 kWh resulting in an effective COS energy rate of $0.033980 per kWh.

Q. Based upon the C&I COSS for DCFC customers, what does the Company propose?

A. The current rate structure for LPL-S is highly correlated to cost causation and is the ideal rate for all customers this size. However, to support the state's goal of promoting EV adoption and to ease cost burdens on DCFC customers during this early phase of market introduction of DCFC facilities, the Company is proposing a Distribution kWh charge to replace its Distribution Summer and Annual Demand kW charges for customer premises that only serve as DCFC facilities. Details of the proposed rate can be found on page - 57 - later in my testimony.

PROPOSED RESIDENTIAL TOU RATES

Overview

Q. Do you propose to include a Residential TOU Rates in PSE&G's tariff for electric service?

A. Yes. The Company will offer two new Residential TOU rates as described by Company witness Ahmad Faruqui, Principal Emeritus with The Brattle Group. The proposed tariff provision is consistent with the mechanism described by Mr. Faruqui and can be found in Figure 4 Summary of Current and Proposed RS Rate on page 13 of Exhibit P-10.

Q. Did you assist Mr. Faruqui in developing the proposed rates?

A. Yes. Mr. Faruqui and I worked closely in developing the proposed residential TOU rates which are discussed in more detail below.

Q. As part of the RS-TOU rates, are there any proposed changes to existing rate schedules?

A. The RS-TOU rates have been developed in a manner that provides for the closing of the RLM Rate Schedule to new customers once the RS-TOU is made available.

Q. Is it reasonable for the Board to consider approval of the proposed RS-TOU rates and corresponding rate design that you are proposing in this proceeding?

A. Yes. It is reasonable for the Board to consider the approval of the Proposed RS-TOU and corresponding rate design. The proposed RS-TOU rates align with cost causation, using cost-based rates developed by a COSS and rate design, as the Company is proposing in this filing, and sends the correct economic signals to customers, allowing them to make accurate economic decisions regarding their electricity usage and, as result, helps reduce future investment requirements and thus reduces future rates for all other customers. Adoption of the proposed RS-TOU rates will serve to encourage the most efficient use of electricity possible at a fair and equitable cost. Cost based rates provide a more fair and equitable allocation of costs across customers, support the correct economic customer decision making process regarding energy usage and related investments, and help keep rates more affordable.

Rate Design Detail

Q. What is the Company's proposal for new TOU rates?

A. The Company proposes two new voluntary residential TOU rates: a Two Period TOU Rate ("RS-TOU 2P") and a Three Period TOU Rate ("RS-TOU 3P").

The RS-TOU 2P has two periods, on-peak from 4pm to 9pm weekdays excluding PJM Holidays and off-peak all other hours.

The RS-TOU 3P rate has three periods, on-peak from 4pm to 9pm weekdays excluding PJM Holidays (same as RS-TOU 2P), off-peak from 12am to 6am and mid-peak for all other times.

Q. What are the objectives used to design these TOU rates?

A. The first objective of the TOU rates is to create rates that would provide customers with time of use pricing options that give customers options to move some of their discretionary, relative to timing, usage to non-peak times, where lower pricing could be offered reflecting the lower costs to serve during off peak times. These time-dependent price options may be of interest to those customers for whom the off-peak pricing meets their usage patterns or for those customers willing to modify their usage pattern to take advantage of the lower non-peak rates.

Q. What is the overall rate design philosophy for the proposed RS-TOU rates?

A. As described in the testimony of Mr. Faruqui, the overall rate design philosophy is to design the TOU rates to be revenue neutral to the aggregate RS Rate Schedule. This implies that the goal is that if the entire RS Rate Schedule would be served on either the RS-TOU 2P or 3P rate with no change is usage, the revenue collected from all customers would be the same.

Q. Can you describe the components of the proposed RS-TOU rates and how they were developed

A. Below is description of each rate component and the basis of how they were developed.

1. **Service Charge**: With the implementation of AMI meters, there is no difference in metering cost from a customer on the RS Rate Schedule. Therefore, the proposed service charge for both the RS-TOU 2P and RS-TOU 3P rates will be identical the RS Rate Schedule service charge.

2. **Distribution Energy kWh Charges**: System Delivery Distribution costs are allocated to customers based upon the customers contribution to Coincident Peak Demand. Since PSE&G uses energy (kWh) charges instead of demand or obligation charges to recover

this cost, the closest rate to collect these costs would be the Summer on-peak kWh charge. However, this would result in a very high summer on-peak kWh charge. To mitigate the difference between the summer and winter charge and still have the price signal aligned with cost causation, the System Delivery component was allocated 1.5 times more to the Summer on-peak vs. the on-peak winter period. Then an adjustment factor was used to ensure that the System Delivery Costs in the proposed RS-TOU rates are equal to the System Delivery costs embedded in the proposed RS Distribution kWh rates.

Local Delivery Distribution costs are allocated to rate schedules by the sum of customers' individual peaks in the rate class. Since individual customer peaks can happen at any time and consistent with the current RS Rate Schedules rate design, the Company proposes to recovery this cost over all energy usage. However, to still send the proper price signals to customers and to minimize the mid and off-peak rates, these costs were also ratioed between time periods. For the RS-TOU 3P rate, the on and mid-peak rates were designed to be two times the off-peak rate. To keep the on-peak rates the same between the 2P and 3P rates, the on-peak contribution of Local Delivery costs designed for the 3P rates was used for the RS-TOU 2P rate with the balance of Local Delivery cost recovered in the longer RS-TOU 2P off-peak period. Then an adjustment factor was used to ensure that the Local Delivery Costs in the proposed RS-TOU rates are equal to the System Delivery costs embedded in the proposed RS Distribution kWh rates.

The proposed RS-TOU Distribution kWh rates without and with SUT are shown below in Table 1.

5n7		$/kWh - w/o SUT	
Rate	Period	Summer	Winter
Distribution	on peak	0.196495	0.144223
3P	mid peak	0.039678	0.039678
	off-peak	0.019839	0.019839
Distribtuion	on peak	0.196495	0.144223
2P	off peak	0.034808	0.034808

5n7		$/kWh - w/ SUT	
Rate	Period	Summer	Winter
Distribution	on peak	0.209513	0.153778
3P	mid peak	0.042307	0.042307
	off-peak	0.021153	0.021153
Distribtuion	on peak	0.209513	0.153778
2P	off peak	0.037114	0.037114

Table 1

The calculation for these distribution rates can be found in workpaper WP-SS-TOU.xlsx.

3. **Supply Charges:** Since Supply rates are determined in BGS proceedings, I developed estimated Transmission and Generation rates, which are revenue neutral to RS rates, to calculate total bill impacts for these proposed rates. The development of the supply rates can also be found in workpaper WP-SS-TOU.xlsx. The Company intends to propose corresponding generation and transmission RS-TOU rates in future BGS proceedings.

Program Details

Q. Which customers could utilize the proposed RS-TOU rates?

A. Any residential customer could choose to be served under this proposed rate.

Q. Would customers be defaulted to RS-TOU rates?

A. No. These rates will be entirely voluntary opt-in options, with no customers defaulted into or required to move to these rates.

Q. Would customers be able to move back to the RS Rate Schedule?

A. The Company proposes that for each residential customer that opts into one of the two new RS-TOU rates, at the end of the initial 12 month period, the Company will provide each customer with reporting showing his or her 12 month bill on the new RS-TOU rate and what this 12 month bill would have been on the RS Rate Schedule. The customer will be offered a one-time refund of the difference if the 12 month bill on the RS-TOU rate was higher compared

to the RS Rate Schedule. This initial 12 month look back provision is incorporated to encourage customers to be more willing to try the RS-TOU rates knowing they will not be financially disadvantaged, and after the initial 12 month period, customers can chose to revert back to the RS Rate Schedule if they wish. The initial 12 month look back provision would only be available to customers who take service under either RS TOU rate during the first 24 months that the rate is available to customers.

Q. Is there any requirement to stay on the rate for any period of time?

A. There will be a requirement for customer to stay on the new RS-TOU rate for a period of 12 months. After being on the rate for a minimum of 12 months, customers would also be able to choose to switch back to the RS Rate Schedule at any time.

Q. What is the estimated implementation cost for these new T OU rates?

A. The new AMI meter system provides more detailed metering data that enables TOU rates and creates the ability to bill time of use rates in the Customer System. Once the proposed rates are approved as part of the rate case, new billing logic that meets stringent financial testing and SOX control standards will require an IT programming, testing and training effort. Also, the 12 month look back provision adds a layer of programming complexity as well. The initial estimate to be able to implement the proposed TOU rates is approximately $1.9 million..

Additionally, IT system changes are required to enable changes to a customer's rates without the need to change the customer's meter. This capability had previously been planned for a later phase of AMI use case deployment and is not currently not one of the 22 AMI Use Cases included in the CEF-EC program.[5] To support efficiency in administration of the

[5] See testimony of Company witness Johnson regarding the 22 AMI Use Cases that are part of the CEF-EC program.

proposed TOU rates, PSE&G recommends including these system changes in the CEF-EC program for deployment by the end of 2024, and requests the BPU's support for this approach.[6]

Q. What would be the time frame to be able to offer new RS TOU rates?

A. The project to implement the new RS-TOU Program would begin upon the effective date of this filing. It is currently estimated to take nine to twelve months after approval of the filing to make the RS-TOU Program available to customers.

Q. Is the Company proposing a customer communications plan for introducing the availability of the new RS-TOU Program and associate rate options?

A. In the several months before the RS-TOU rates become available, the Company will perform an initial awareness communications plan to all residential customers utilizing varied channels such as the web, bill messages, bill inserts, and digital advertisements at an estimated cost of $2.0 million. After the kickoff campaign, additional awareness campaigns would be done at regular intervals for the next two years at an estimated $500,000 per year. Additionally, there will be certain targeted communications to those customers identified as likely to be interested in the TOU rates, such as EV customers.

Q. What assumptions has the Company made regarding customer adoption of TOU rates?

A. The Company has proposed entirely voluntary adoption for residential TOU rates and not made any assumptions or targets for residential customer signups. It is assumed that the TOU rates will be of interest to price sensitive customers with usage that allows them to move that usage to off-peak periods. Some percentage of EV owners looking to save money would be likely adopters.

[6] This work can be managed within the existing CEF-EC program budget.

Q. Will there be increased expenses associated with the introduction and support of TOU rates?

A. Yes. Aside from the implementation and communication costs, there will be additional incremental costs related to supporting customers through these TOU options. While self-serve options such as an online rate analyzer will be available, it is anticipated that TOU options will drive increased calls from customers with questions. Additionally, the transitional items being offered, providing the 12 months bill comparison, possible refunds, and ability to change rates, will drive incremental calls and additional work in the billing department to support customers through this transition as customers get comfortable with TOU rates. In the initial three years of the TOU introduction, these incremental expenses are estimated to be in the range of $1.7 million to $3.3 million annually, including risk and contingency.

Q. Has the Company incorporated these RS-TOU rates into the calculated revenue requirement?

A. No. These rates have been designed to be revenue neutral with the proposed RS Rate Schedule, so there was no need for a change to the calculated revenue requirement based on the new TOU rates.

Q. How will the revenue collected under the RS-TOU 2P and RS-TOU 3P Rate Schedules be treated for the Conservation Incentive Program ("CIP")?

A. Since these TOU rates have been developed to be revenue neutral relative to the RS Rate Schedule, the Company is proposing to treat the new TOU Rate Schedule as customers served under the RS Rate Schedule. Therefore, the net distribution per customer will be based upon the RS Rate Schedule revenue per customer and the Company will have the same financial incentive to serve a residential customer either on the RS or RS-TOU rates.

Q. Can you please summarize all the estimated expected costs to implement the RS-TOU?

A. All of the estimated expected costs to implement Residential TOU for the first three years is estimated to total $12.4 million.

Q. How does the Company propose to recover the implementation costs associated with the new RS-TOU rates?

A. The Company proposes that the implementation costs be deferred with all the corresponding regulatory assets earning carrying charges at the Company's latest approved WACC. These costs and corresponding regulatory assets would be reviewed for prudency and cost recovery in the next base rate case.

Q. How does the Company propose to recover the customer support and customer communication and education expense costs associated with the new RS-TOU rates?

A. The Company proposes that the implementations costs be deferred and reviewed for prudency and recovery in the Company's next base rate case.

PROPOSED DCFC DISTRIBUTION KILOWATT-HOUR CHARGE

Q. Have you proposed a new Distribution kWh charge for customers who receive service solely as a DCFC facility serviced under the LPL-S Rate Schedules in lieu of the current annual and summer demand charges?

A. Yes.

Q. Can you please describe the charge?

A. As described in the C&I EV COSS section on page - 49 -- 49 - earlier in my testimony, the kWh cost-based rate based upon the historic usage of 34 DCFC customers is $0.033980 per kWh without SUT. To develop a Distribution kWh rate that is comparable to the current Annual and Summer Demand Charge for the LPL-S Rate Schedule, the rate is adjusted for the ratio of the proposed LPL-S Annual and Summer Demand Revenue of $215,064,000 versus

its cost to serve of $229,721,897 or 0.93619. As a result, the proposed DCFC Distribution kWh charge is $0.031812 per kWh without SUT ($0.033920 per kWh with SUT).

STREETLIGHTING CHANGES

LED Street Lighting

Q. Is the Company proposing changes to Streetlighting Rate Classes?

A. The Company proposes to no longer offer standard, non-LED streetlights in the BPL (Body Politic Lighting Service) and PSAL (Private Street and Area Lighting Service) Rate Schedules for new installations. The Company would continue to provide only maintenance and electric delivery service for existing non-LED luminaires that began taking service prior to the Board's approval of this proposal. The Company will not proactively replace functioning non-LED luminaires.

Q. Why is the Company proposing this?

A. This is being done to encourage the transition tor energy efficient LED luminaires and the anticipated lack of availability and the cost of non-LED luminaires, upon approval by the Board.

Q. Other than the changes to the charges under the Street Lighting Rate Schedules, what other changes is the Company proposing as part of this filing?

A. The Company proposes that during any future maintenance activities on an existing non-LED Luminaire (bulb, photocell, or fixture failures), the Company may, at its sole discretion, replace a non-LED streetlight luminaire with an equivalent LED streetlight luminaire.

Q. What are the changes to the Streetlighting Tariff?

A. PSE&G proposes to close all non-LED Luminaires within the BPL and PSAL Rate Schedules and add new LED Luminaires.

Q. Are there energy efficiency and environmental benefits from the deployment of LED Luminaires?

A. Yes. LED luminaires are environmentally friendly as they reduce energy consumption and therefore carbon dioxide emissions. Also, LED luminaires are effective at managing light pollution.

Q. What are the implications with respect to the streetlight assets associated with the replacement of the non-LED luminaires with LED luminaires?

A. PSE&G's current streetlighting rate schedules provides that "Public Service has the right to replace obsolete luminaires, poles and all other associated equipment with equivalent equipment without the consent of its customers." PSE&G considers all non-LED luminaires that have an LED equivalent to be obsolete equipment and subject to replacement with an equivalent LED Luminaire, opportunistically when repairs or replacements are needed. PSE&G proposes a change to the tariff to move all obsolete fixtures to the closed section of their respective tariffs.

Q. How will the change from non-LED luminaire to new LED luminaire fixture due to any type of failure (bulb/photocell/luminaire) in the normal course be handled from an accounting perspective?

A. The non-LED luminaire will be retired in the normal course of business.

Q. Will the company incur incremental costs by replacing existing non-LED luminaires failures with an LED luminaire?

A. While the Company manages its current non-LED inventory prudently and will try to minimize the amount inventory in anticipation of the changes discussed above, it is likely there would some amount of obsolete inventory that would result in an inventory write-off and associated incremental expense.

Q. How does the Company propose to recover these costs?

A. PSE&G proposes to defer these costs for recovery in the Company's next base rate case.

Rate Schedule Body Politic Lighting Service ("BPL")

Q. Please describe the rate design for Rate Schedule BPL.

A. As stated previously in my testimony, the Company is proposing to close the non-LED luminaires in the BPL Rate Schedule upon approval by the Board. Since the Company is proposing closed all non-LED luminaires and its present revenue is close to its cost to serve, , the Company proposes to limit the Distribution Charge utilizing the standard increase limits and to increase the Monthly Charges for poles and luminaires by an overall increase of 10% of revenue .

The results of the Rate Schedule BPL rate design are shown on page 37 of Schedule SS-E11. The general format of the calculations is described on the first page of that Schedule. In accordance with the Stipulation approved by the BPU in Docket No. ET01120830, the Company offers four distinct service offerings of luminaires and poles under rate schedule BPL, each necessitating a unique set of prices, as follows:

- Specialty luminaires and poles having more than 50 units in service or new LED luminaires,
- LED luminaires and poles that are currently in the Tariff
- Current specialty luminaires and poles;
- Standard and luminaires and poles no longer available.

The first service offering is for LED luminaires and poles that are currently billed as specialty units and meet the 50-unit breakpoint discussed above or new LED luminaires that will take the place of equivalent non-LED units. These facilities are proposed to be offered as

standard units whose price will be listed in the tariff. The units are referred to in the workpapers as "Tariff New." Units already installed and being billed to customers will continue to be billed at the current customer specific charges already established. The individual tariff prices for these units are the greater of either the levelized annual revenue requirement of current costs calculated at Company's proposed overall rate of return, or the highest price charged to an existing specialty customer. .

The second service offering is for luminaires and poles that appear in the Rate Schedule BPL as Standard items and are referred in the workpapers as "Tariff Existing" Since we are propsing to close all non-LED luminaires, only the exiting tariff LED luminaries and poles are in this set. Unit prices for these facilities were first calculated for different luminaire or pole types based on the levelized annual revenue requirement of current costs calculated at the Company's proposed overall rate of return. Proposed changes in the individual Standard pole charges were limited to a range to ensure an aggregate increase 10% to all luminaire and pole revenue.

The third service offering is for current Specialty units, which are referred to in the workpapers as "Specialty." Units of this type already installed and being billed to customers will continue to be billed at the current customer specific charges. New Specialty units will be offered for installation after the conclusion of this proceeding and will follow the same customer specific formula as detailed in the Rate Schedule. The only change proposed for this service offering is an updated Maintenance Charge as set forth in the Rate Schedule.

The final type of offering is for current standard units that are no longer available for new installations. As previously discussed, this will include all non-LED luminaires such as Incandescent, Mercury Vapor, Metal Halide, High Pressure Sodium or Induction, units as well

as some obsolete LED units. These are referred to in the workpapers (and in the Tariff) as "Tariff Closed" units.

For these proposed "Tariff Closed" standard non-LED luminaries, prices were adjusted to ensure that the total bill for the new LED equivalents would be equal to or lower than the proposed non-LED total bill. The remaining non-standard Tariff Closed items were adjusted to ensure that the overall luminaire and pole increase will be limited to a range to ensure an aggregate increase of 10% to all luminaire and pole revenue.

The final proposed individual LED luminaire and pole charges for "Tariff Existing" items were determined through iteration, subject to the limits discussed above, such that the overall proposed distribution revenue target for Rate Schedule BPL from page 2 of Schedule SS-E9 was achieved.

The distribution costs related to the use of the electric distribution system to deliver electricity to the streetlights are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments by the total kWh delivered. The Maintenance Charges that are listed in Rate Schedule BPL for use in calculating specialty prices and included in the charges for standard luminaires and poles were updated based on the latest information from the Company's accounting records.

Rate Schedule Body Politic Lighting Service From Publicly Owned Facilities ("BPL-POF")

Q. Please describe the rate design for Rate Schedule BPL-POF.

A. The Company closed this Rate Schedule at the conclusion of the 2018 Rate Case. and the rate class is grandfathered to premises receiving service only up to the date of October 31, 2018. Under Rate Schedule BPL-POF, the Company continues to provide only maintenance and electric delivery service for existing publicly owned street lighting systems that began

taking service prior to the closing date of October 31, 2018. The Rate Schedule includes monthly charges for those luminaire types presently being served.

The distribution costs for this service are related to the use of the electric distribution system to deliver electricity to the streetlights and are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments divided by the total kWh delivered.

The fixed per unit charge for each luminaire is designed to provide for recovery of only the maintenance costs associated with providing service. The Company has no investment in the luminaires because all equipment is supplied, installed, and owned by the customer. The unit prices for each luminaire type were set in a manner identical to that of the Maintenance Charge for Rate Schedule BPL to recover the Proposed Distribution Revenue for Rate Schedule BPL-POF as set forth in page 2 of Schedule SS-E9.

The Company proposes this class receive the overall average Distribution percentage increase as shown in Column 7 of Page 2 of Schedule SS-E9. Similar to Rate Schedules BPL and PSAL, the Company proposes to increase the Distribution Charge per kWhutilizing the standard increase limits, the Monthly Charges per Unit to recover the remainder of the revenue for this rate schedule.

Rate Schedule Private Street and Area Lighting Service ("PSAL")

Q. Please describe the rate design for Rate Schedule PSAL.

A. The rate design used for Rate Schedule PSAL individual luminaires and poles is similar to the method used for Rate Schedule BPL individual luminaires and poles. The only difference is that because this type of lighting service is optional, as customers may install their own systems that provide comparable lighting, it is appropriate that overall pricing of Rate Schedule PSAL should not be limited to the cost based revenue requirements as indicated by

the COSStudy. The only difference for PSAL compared to BPL is the proposed changes for individual Standard pole charges were limited to a range to ensure an aggregate increase of 20.607% to all luminaire and pole revenue. This is shown on Column 7 of Page 2 of Schedule SS-E9.

The distribution costs for this service are related to the use of the electric distribution system to deliver electricity to the streetlights and are calculated by dividing the revenue requirements from the Local Delivery and System Delivery segments by the total kWh delivered.

RATE DESIGN FOR FUTURE ADJUSTMENT BETWEEN BASE RATE CASES

Q. Will the same method for revenue changes being proposed in this proceeding be used for future rate adjustments for IIP Proceedings and similar base rate adjustment programs prior to the conclusion of the next base rate?

A. While the method would be similar, the Company is proposing minor modifications that were used in similar rate adjustments since the 2018 base rate case.

Q. What modifications is the Company proposing?

A. Since the Streetlighting Rate Schedules (BPL, BPL-POF and PSAL) Luminaire and Pole Charges are specifically intended to recover the costs for those assets and have no cost relationship to investments being made in the Company's IIP proceedings and similar base rate adjustment programs, the Company proposes to exclude the luminaire and pole revenue from being included in the interclass revenue allocation for the corresponding future rate increases. Only the Distribution Charge revenue for the Streetlighting Rate Schedules would be included utilizing the same interclass revenue increase limits and the same rate design method specifically to the Distribution Charges proposed in this proceeding.

TAX ADJUSTMENT CREDIT ("TAC")

Q. Please briefly describe the TAC Mechanism.

A. The TAC mechanism was established in the 2018 Rate Case Order, to flow back certain tax benefits to customers.

Q. Please briefly describe PSE&G's proposed TAC adjustments.

A. As described in more detail in the testimony of Mr. Pardo, the Company is proposing the following adjustments to the TAC:

1) In addition to continuing to flow back the benefit of the historic Safe Harbor Adjusted Repair Expense ("SHARE") deduction, the Company proposes to flow back to customers the net federal tax benefit associated with the historical Mixed Service accumulated deferred income taxes ("ADIT") balance over approximately five years.
2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case; and
3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of excess deferred income taxes ("EDIT") and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery proceeding. In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology.

Q. Does the Company have an amortization schedule for the proposed amortizations?

A. Yes, the proposed amortizations are included in summary format in rows 167-170 in worksheet 'RevReq-E' of WP-SS-TAC-1.xlsx for 2025 through 2028.

Q. How does the Company propose to modify the TAC revenue requirement formula based upon the changes discussed previously?

A. The TAC revenue requirement formula is calculated monthly and will be modified with the ***bolded items*** below:

> *TAC Revenue Requirement = (Amortization of Protected ADIT Balance +(Amortization of Historic SHARE ADIT) Balance +* ***(Amortization of Historic MSC Deduction ADIT Balance*** *+ After-tax Return on Cumulative Historic SHARE Deduction ADIT Change +* ***After-tax Return on Cumulative Historic MSC Deduction ADIT Change*** *+* ***Pre-set*** *SHARE Deduction Flow-Through +* ***Pre-Set MSC Deduction Flow-Through*** *+ IRS Audit Electric Adjustments + Other Major Electric Tax Adjustments)* ******* *Electric Revenue Factor*

See Schedule SS-TAC-2E for the monthly net revenue requirement calculations.

Q. What is the TAC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The electric net revenue requirement for the initial 16-month period of September 1, 2024 through December 31, 2025 is a credit to electric customers of $174.4 million or $132.4 million on an annualized basis. See Schedule SS-ETAC-1.

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC")

SRC Mechanism

Q. Please briefly describe the Company's proposed SRC.

A. As described in the testimony of Mr. McFadden, the Company is proposing a SRC to:

1. Recover the deferred major storm costs that have been incurred since 2018 with interest.

2. Defer and then recover future major storm costs, including interest, through subsequent true-up filings.

Q. Please describe the methodology used to calculate the SRC recovery.

A. The Company is proposing a new Distribution Adjustment Charge ("DAC") clause in its electric tariff with the SRC as a new component of the DAC. The DAC was proposed by the Company in its COVID-19 cost recovery filing where COVID-19 Recovery Charge would also be a component of the DAC. The details of the SRC and the recovery mechanism are described below. The following formula describes the SRC mechanism:

SRC Balance = Prior Month SRC Balance – SRC Revenue + Incremental Deferred Major Storm Costs + Interest Expense

Q. How will the SRC be charged or refunded to customers?

A. The Company proposes to charge or refund the SRC through a new component of the Company's proposed DAC in the Company's electric tariff. The charges will be applied to each kWh of a customer's usage and will apply to all electric customers.

SRC Components

Q. What is the Initial SRC Balance?

A. The Initial SRC Balance is the total incremental deferred major storm costs associated with major storms since the Company's last Base Rate Case in 2018 prior to the implementation of the SRC rate.

Q. What are the "Incremental Deferred Major Storm Expenses?"

A. The Incremental Deferred Major Storm Costs are those monthly costs that occur after the implementation of the SRC rate.

Q. What is the "Interest Expense?"

A. The Interest Expense is the monthly carrying costs related to the SRC Balance. It is calculated as following ((Prior Month SRC Balance + (– SRC Revenue + Monthly Activity +

Prior Month SRC Balance)) / 2) x (Annual Interest Rate / 12). In calculating the Interest Expense, the annual interest rate is based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month. If both commercial paper and bank credit lines have been utilized, the weighted average of both sources of capital shall be used. In the event that neither commercial paper nor bank credit lines were utilized in the preceding month, the last calculated rate will be used. The interest rate shall not exceed PSE&G's overall rate of return as authorized by the Board as utilized in calculating revenue requirements for the corresponding period. The calculation of the monthly interest can be found in Schedule SS-SRC-1E, Page 1.

Q. How does the Company propose to calculate the initial SRC Rate?

A. The Company proposes to set the initial SRC Rate to recover these costs over a three-year period including interest. The rate will be a rate applied to all electric customer. See Schedule SS-SRC-1E, Page 2 for the calculation.

Q. When does the Company propose to submit subsequent SRC filings to change the SRC?

A. The Company plans to submit a periodic SRC filing to change the SRC rate if warranted based upon the projected SRC over/under balance.

Q. When will storm costs be reviewed for prudency?

A. The Company proposes that all storm costs will be reviewed as part of subsequent SRC filings.

Q. When is the initial implementation of the SRC anticipated to occur?

A. The SRC is proposed to be effective September 1, 2024 corresponding to the change in base rates as a result of this proceeding. If the Board approves new base rates earlier or later

than September 1, 2024, the initial rate period and corresponding rate will be adjusted accordingly from the effective date of the Board Order.

Q. What is the SRC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The electric net revenue requirement for the initial annual period of September 1, 2024 through August 31, 2025 is a charge to electric customers of $38.0 million. See Schedule SS-SRC-1E.

TARIFF CHANGES

Q. Are you proposing any further changes to the proposed tariff?

A. Yes. Please refer to the Guide to Electric Tariff Changes, Exhibit P-1 Schedule 2.

LOSSES

Q. Is the Company proposing to update electric losses?

A. No, the Company is not proposing any update to electric losses in this proceeding.

CLEAN ENERGY FUTURE – ELECTRIC VEHICLE ("CEF-EV") FUTURE RATE ADJUSTMENT MECHANISM

Q. Why is the Company proposing a future rate adjustment mechanism in the filing?

A. In accordance with the CEF-EV Order, the Company anticipates that expenditures on the CEF-EV program will extend more than six months beyond the end of the test year and require annual rate adjustment filings. As stated in the CEF-EV Order, paragraph 24:

> CEF-EV investment that is not likely to be in-service by the end of six (6) months after the end of the test year, shall be deferred and placed in a regulatory asset. The Signatory Parties agree the Next Base Rate Case will remain open so that CEF-EV investment placed in service more than six (6) months after the end of the test year in the Next Base Rate Case will be reviewed and placed into rates, if deemed reasonable and prudent, as soon as practicable after the associated infrastructure has been placed into service, through annual roll-in filings following the Next Base Rate Case. The annual roll-in filings will include three (3) months of forecast data that

will be trued-up with actual data no later than 20 days after the end of the final forecast month. The annual roll-in filing will request that new rates be implemented three (3) months after the end of the final forecast month. The schedule of such annual roll-in filings shall be determined in the Company's Next Base Rate Case.

Q. What costs will be included in the future CEF-EV rate adjustments?

A. The CEF-EV Order permits the Company to recovery the following assets in future rate adjustments.

1. Portions of Pole to Meter ("PTM") investments that would have been collected via Contribution in Aid of Construction ("CIAC") payments from CEF-EV participants.
2. The regulatory assets from the deferral of the Behind the Meter ("BTM") rebates to CEF-EV participants.
3. The regulatory asset from the deferral of the Depreciation and Amortization expense associated with the assets from Item 1 and 2 above.
4. IT Investments that were made to support the program
5. The regulatory asset from the deferred return on the Items 1 through 3 above.
6. The regulatory asset from deferred Program O&M expense

Q. How does PSE&G propose to calculate the revenue requirements?

A. PSE&G proposes to calculate the revenue requirements associated with the CEF-EV's costs using the following formula:

*Revenue Requirements = ((Rate Base * Rate of Return) + Net of Tax Amortization and/or Depreciation + Tax Adjustment)* Revenue Factor*

This calculation is similar to the calculations utilized in PSE&G's Infrastructure Programs as approved by the Board in their respective Board Orders. The Company proposes to recover the revenue requirements through annual rate adjustment filings as described below, consistent with the Order approving the Program.

Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation.

The term "Rate of Return" is PSE&G's overall weighted average cost of capital ("WACC") for the Program. PSE&G is proposing a return on its CEF-EV rate base based upon an authorized return on equity ("ROE"), Long Term Debt, Customer Deposits and corresponding capital structure including income tax effects. The Company proposes to utilize the latest WACC authorized by the Board in the Company's base rate case proceeding(s). See Schedule MPM-04 for the calculation of the proposed WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in any subsequent electric, gas, or combined base rate case would be reflected in the appropriate corresponding rate adjustment filing explained in more detail below. Any changes to current Federal or State tax rates would also be reflected in an adjustment to the WACC. Additionally, the Company is proposing that for these future CEF-EV rate adjustments, the embedded cost of long-term debt should be the actual rate at the time the Company submits its update for actual results in the associated proceeding.

The term "Rate Base" refers to Gross Plant from the assets described earlier less the associated accumulated depreciation and/or amortization and less Accumulated Deferred Income Taxes ("ADIT"). Gross Plant is equal to all the assets described above and Allowance of Funds Used during Construction ("AFUDC") – both debt and equity components.

ADIT is calculated as Book Depreciation (Tax Basis) less Tax Depreciation, multiplied by the Company's effective tax rate, which is currently 28.11%. Cost of Removal expenditures

are depreciated 100% in the year incurred for tax purposes. Please see Table 2 below for the book and tax depreciation rates for each asset, which were approved in the CEF-EV Order.

Asset	**Annual Book Depreciation Rates**	**Tax Depreciation Years/Type[7]**
Pole to Meter	2.00%	20 / MACRS
IT Investments	3.33%	3 / SL
Regulatory Asset (excl. O&M)	3.33%	Expense
Regulatory Asset - O&M	20%	Expense

*Based on investment based weighted average of EV Depreciation Rates

Table 2

Any future changes to the book, or tax depreciation rates, such as, but not limited to, reinstatement of "bonus depreciation" during the construction period of the Program and at the time of each base rate adjustment, will be reflected in the accumulated depreciation and/or ADIT calculation described above. The "Net of Tax Depreciation and/or Amortization" allows for recovery of the Company's investment in the Program assets over the useful book life of each asset class. For Plant in Service investment, the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. Any future changes to the book depreciation or tax rates during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the net of tax depreciation expense calculation described above.

The term "Tax Adjustment" refers to any applicable tax items that may impact the revenue requirement calculation for the Program.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes, the BPU and Rate Counsel ("RC") Annual Assessments Fees. The tax rates reflect the current federal tax rate of 21%. The BPU/RC Assessment Expenses consist of

[7] "MACRS" = Modified Accelerated Cost Recovery System, "SL" = Straight Line

payments, based upon a percentage of revenues collected (updated annually), to the State based on the electric and gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2023 fiscal year assessment. Any future changes impacting the revenue factor during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the revenue factor described above.

Q. Do you provide a schedule showing a sample calculation of the revenue requirements?

A. Yes. See Schedule SS-CEF-EV-1 for a sample calculation of future revenue requirements for the CEF-EV program.

Q. How does the Company propose to recover the revenue requirements as described above?

A. The Company proposes to recover the revenue requirements associated with the Program via new CEF-EV rate components of its Infrastructure Investment Program Charges ("IIPCs") for the Electric Tariff. While not an IIP, this mechanism will allow for the inclusion of the CEF-EV rate adjustments into base rates.

The filing schedule based upon the Initial Filing date along with corresponding timing for, Investment as Of, Update for Actuals Filing, and Rates Effective dates for all electric and electric rate adjustment filings, assuming Board approval of this proceeding by September 1, 2024, is listed in the table below.

Each Initial Filing shall provide the actual cost and forecast for investment data, revenue requirement calculations, proposed CEF-EV rates, and related data to support rates based on CEF-EV costs.

The Update for Actuals Filing, updates all forecasted cost and investment data, revenue requirement calculations, proposed CEF-EV rates, and related information from the Initial

Filing to data based on all actual historical data. CEF-EV investments included in rates in the Update for Actuals Filing shall only include CEF-EV investment not in the Company's base rates and actually placed in-service according to the schedule below.

The Rates Effective dates for each filing below shall be as indicated in Table 3 below – the first day of the month following five months following the due date of the Initial Filing. The Company proposes three rate adjustment filings with dates to be determined based upon 60 days notice prior to the initial filing. Table 3 below shows the Company's proposed filing timeline for each rate adjustment filing.

CEF-EV Rate Adjustment Schedule			
Initial Filing	**Investment as Of**	**Update for Actuals Filing**	**Rates Effective No Earlier Than**
TBD	TBD + 2 mo	TBD + 3 mo	TBD + 5 mo + 1 Day

Table 3

Q. What rate design is the Company proposing to use for this base rate adjustment?

A. The Company proposes to use the rate design from the most recently approved base rate case proceeding.

Q. What will be the source of the capital expenditures you use to calculate the revenue requirements for future CEF-EV adjustments?

A. The actual and projected monthly cash flows for the Program will be provided in separate testimony from the CEF-EV Program witness.

Q. Will the Company continue to calculate a monthly investment deferral on CEF-EV investments that are recovered in base rates or future rate adjustments?

A. No. Once investment is included in customer rates through a base rate case proceeding or future rate adjustments, it will be excluded from the CEF-EV Monthly Investment Deferral calculation described above.

Q. How will the CEF-EV Regulatory Asset be reflected in subsequent base rate case proceedings?

A. Consistent with the CEF-EV Order, the Company will continue to seek recovery of and on the unamortized CEF-EV Regulatory Asset. This will include any Deferred Monthly Investment not yet recovered in rates and return on the unamortized CEF-EV Regulatory Balance as a component of rate base in the same manner as any other Utility Plant.

STAFF COSS METHODOLOGY

Q. Please explain why you are conducting the Staff COSS.

A. In the 2018 Rate Case proceeding, the Company agreed to perform a COSS in the manner prescribed by Staff. In accordance with this requirement, the Staff COSS and the summary of the resulting functional revenue requirements by rate class are being submitted with the Company's rate case filing. Specifically, Schedule SS-E13 contains the details of the complete COSS utilizing Staff's Method, Schedule SS-E14 is the Summary Report by Functional Segment based on Staff's Method, Schedule SS-E15 is the Functional Cost Summary of the Cost of Service Study results based on Staff's Method, and Schedule SS-E16 contains the Service Charge Calculations based on Staff's direction.

In the Stipulation that resolved the 2018 Rate Case, the parties made it clear that they were not agreeing that the Staff COSS was appropriate, was consistent with cost causation principles, or would be a useful guide in determining just and reasonable rates. Specifically, the Stipulation stated (at 11-12):

> All parties will be free to submit any number of alternative cost of service methodologies for the Board's consideration in future cases. The Company and

any Signatory to this agreement will have the right to file and support any COSS method it considers appropriate.[8]

Q. Does the Company believe that the Staff COSS provides a reasonable foundation for establishing just and reasonable rates in this proceeding?

A. No. The Staff COSS Methodology is not an appropriate methodology to use to establish just and reasonable rates because it does not achieve a result that is tied to cost causation. Instead, the Staff COSS method goes to great and often extraordinary lengths to allocate and functionalize costs away from residential customers and onto the shoulders of commercial and industrial customers. While it may be reasonable to moderate the level of increase to be borne by residential customers, the vehicle for doing so should not be a COSS that transfers costs to businesses operating in the Company's service territory. The Company has taken reasonable steps to moderate the increase in rates for Rate Schedules RS and GLP customers with its gradualism-based recommendations that limit the increases for those classes.

Q. What is the primary reason that you believe that the Staff COSS is inappropriate?

A. The fundamental error in Staff's Method for the vast majority of costs is that it proceeds from an assumption that a significant portion of the cost of electric distribution assets should be allocated to the rate classes based on the amount of energy consumed by each class. This general method is applied to virtually all assets in FERC Accounts E360 to E368, which comprise about 81% of the Company's total gross electric plant.

The method used in the Staff COSS to functionalize and allocate most costs has existed for many years and is usually referred to as the "Average and Excess" methodology. However, historically the "Average and Excess" method was used to allocate costs of electric generation

[8] 2018 Rate Case Order at Stipulation ¶ 25.

plant and gas production facilities where arguably there is an energy component because there is investment beyond that necessary to provide capacity at the time of peak load. There is no linkage between this methodology and electric distribution plant costs or operations. Contrary to the assumptions underlying the Average and Excess method, the Company's distribution planners and designers plan and install facilities to meet the peak demands of customers. The design of those facilities is not based on the amount of energy (kWh) they consume.

Chapter 6 of the NARUC Manual, which the Company has generally relied on for functionalization and allocation concepts, describes in detail various methods of functionalizing (or classifying) and allocating electric distribution plant. Table 6-1 on Page 87 of the NARUC Manual shows the general classification of each of the distribution plant accounts into either a demand related or customer related component. More specifically, Part II of this Chapter, which starts on page 90 discusses various allocation techniques and calculations, begins as follows:

> *"When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs."*

Nowhere in the NARUC Manual does a suggestion appear that the cost of electric distribution facilities should be classified or allocated on the basis of energy usage.

The Staff COSS suggests that because distribution facilities carry the "average" load of customers, costs should be allocated based on the average load or even the number of kWh that flow through the wires. This methodology unreasonably ignores the fact that the vast majority of the costs of the distribution system are not caused by its average use. If the system were designed to transport deliveries at only the average amount of electricity, or the amount of energy that is transported and delivered on an annual basis, it would be a much different

system. However, no responsible designer of an electric distribution system would ever design a system that would permit delivery of only the average daily or average annual use. Electric distribution system costs are incurred to serve the expected peak load or any particular circuit.

Q. Do you have particular concerns with the manner in which the Staff COSS methodology classifies and allocates the costs of particular electric distribution accounts?

A. Yes. These concerns are as follows:

Accounts E360 to E362, E365, E366, E367 and E368

These accounts include land, local distribution headquarters, substations, overhead conductors and devices, underground conduit, underground conductors and devices, and line transformers. Staff's COSS requires both the costs of this plant and the expenses associated with this plant to be separated into energy-related and demand-related components and allocated across the rate schedules using a kWh allocation for the energy-related portion and CP allocator for the demand costs, respectively. Staff's proposed classification and allocation ignores the fact that there is no relationship between the costs incurred for these plant items and the amount of energy consumed by various rate classes over an annual period.

Accounts C389 to C399 – Common Plant and E303 Intangible Plant

In Staff's COSS the plant and associated depreciation reserve booked to C389-C399 – Common Plant and to C303 – Intangible Plant associated with meter reading was separated into a customer related and demand related component. The allocation of the customer related portion is the same as the Company's methodology, but the demand related portion was allocated using the class non-coincident peak ("NCP") allocator.

The class NCP is a measure of the peak of each class of customers, regardless of when it occurs. Although used in past cost allocation studies by the Company, it is less accurate than

the use of both the actual CP and actual sum of individual customer demands. There is no reason to use an approximate substitute (the NCPs) when the real drivers (the CPs and sum of individual customer demands) are available. For these reasons, Staff's method of allocation of Common and Intangible Plant is unreasonable.

Accounts E902 – Meter Reading Expenses & E903 - Customer Records and Collection

Under the Staff COSS, expenses booked to these accounts are separated into a customer-related and demand-related component via a 50% - 50% split. Staff's 50% - 50% spilt between customer-related and demand-related components is not supported by any explanation or cost justification. Classifying basically fixed meter reading costs as demand-related for recovery through variable energy or demand charges violates the most fundamental cost classification and allocation principles. The amount of energy used has no bearing on the cost to read a meter. The majority of the time a meter reader spends is not the actual reading of the meter, but simply travelling from one meter to another. Itis independent of the type, size, or usage of the customers in that class. The variable that drives the total meter reading related costs booked to these accounts is the number of customers. Staff's classification of meter reading expenses as demand costs should be disregarded.

Subsequent Base Case Requirements

Q. Do you believe that the Company should be required to complete the Staff COSS in subsequent base rate case filings?

A. No. The Company is requesting that this requirement not be included for the filing of its next base rate case.

Q. Does this conclude your direct testimony?

A. Yes. It does.

APPENDIX E1 - DETAILED REVIEW OF COST OF SERVICE STUDY

Set forth below are details concerning the COSS Modeling Procedures as well as the functionalization and allocation of particular costs in the Company COSS.

Modeling Procedure

After expenses or plant investment-related costs have been entered into the COSS model, usually by FERC account or groups of accounts, one modeling allocator is also entered which performs two functions. The allocator shows:

1. Which of the six segments, or functions, the particular plant or expense item has been attributed to, and
2. The basis on which the particular plant or expense item has been allocated across the rate classes.

The COSS model starts the calculation procedure by allocating the respective plant and expense items to rate classes. Rate revenues for each rate class are then target balanced such that the resulting ROR for each of these rate classes achieves the Company's proposed overall ROR. The model continues by separating all plant and expense items into the appropriate functional segment by rate class, according to the modeling allocator assigned to the particular plant or expense item.

ALLOCATOR NAMING CONVENTION

For consistency and simplicity of bookkeeping, a naming convention has been developed for the modeling allocators.

Direct Allocators

All modeling allocators that end in a dash and a number (such as SUMPK@PRI-04) are direct allocators, meaning that they:

1. Allocate the plant or expense item based on an external constant as indicated by the name of the modeling allocator. For example, the "SUMPK@PRI " in the above allocator denotes the sum of all customers' greatest peak demands as observed at the primary lines, and
2. Segments, or functionalizes, the plant or expense item into one of the six segments as indicated by the trailing number. For example, the "-04" from the above allocator denotes the Local Delivery segment. The segment numbering method used in our analysis is as follows:
    - Segment #2 – Street Lighting
    - Segment #3 – Access
    - Segment #4 – Local Delivery
    - Segment #5 – System Delivery
    - Segment #6 – Customer Service
    - Segment #7 – Measurement

Note that segment #1 is not used.

Indirect Allocators

All modeling allocators that do not end in a dash and a number (such as A&GEXP) are indirect allocators, meaning that they will both segment and allocate costs in the same proportion as other individual or groups of plant or expense items. The names of these modeling allocators are an indication of the items upon which this process takes place. In this example, the A&GEXP allocator segments and allocates costs in the same proportion as the Administrative and General ("A&G") expenses in aggregate.

ALLOCATION DETAILS

Intangible Plant

Electric intangible plant (Accounts E301 to E303) was not included in the study.

Production Plant

There is no Production Plant on the Company's books.

Transmission Plant

All of transmission plant (Accounts E350 to E359) is excluded from the Cost of Service study as I have previously discussed since it is not related to the regulated electric distribution business.

Distribution Plant

The majority of Distribution Plant (Accounts E360 to E374) (Schedule SS-E5, pages 1-2, lines 9 to 20) have been functionalized as follows:

- Substations, poles, wires, circuits and transformers have been functionalized either to the Local Delivery or the System Delivery segments
- Electric services have been functionalized to the Access segment
- Meters to the Measurement segment
- All electric street lighting related equipment to the Street Lighting segment

After this functionalization was completed, each account was then examined to determine the proper allocation of the functionalized costs across rate classes. Investment segmented as Local Delivery was allocated consistent with the prior discussion, to the applicable rates based on the sum of the applicable customers' individual peak demands other than specific exceptions as noted.

Investment segmented to the System Delivery segment was allocated across the applicable rate schedules based on each applicable class's contribution to the coincident peak (also known as the CP). The details of the functionalization and allocation for each of the major Distribution Plant accounts are as follows:

E360 - Land & Land Rights

The investment in land or right-of-ways related to directly providing service to the few customers on Rate HTS-HV was directly assigned to this rate. The investment in this Account associated with substations follows the functionalization and allocation of the substations (recorded in Account E362 Station Equipment). The remaining investment in this account is attributed to local distribution headquarters, which follows the functionalization and allocation of all distribution plant in aggregate.

E361 - Structures and Improvements

The portion of investment in this account associated with substations follows the functionalization and allocation of Account E362 Station Equipment. The remaining portion is attributed to local distribution headquarters plant and follows the functionalization and allocation of all distribution plant in aggregate.

E362 - Station Equipment

Distribution investment in switching stations was segmented to the System Delivery segment and allocated to all customers served at 26 kV (on Rate HTS-sub) and the remainder of the load for primary and secondary customers based on their contribution to CP.

The distribution plant attributed to High Voltage substations (termed class H substations) was also segmented to the System Delivery segment. These substations convert either 69 kV, 138 kV or 230kV power directly to primary voltages (usually 13 kV). Since this type of substation only provides service to primary and secondary customers, the investment

was allocated across rates serving customers at primary and secondary voltages based on the CPs of these rate classes.

Plant recorded for all other substations, referred to as the subtransmission classes (A, B, D, and other classes of substations), were segmented to the System Delivery segment and allocated across the rate classes serving primary and secondary voltage customers based on the CPs of these rate classes.

E364 - Poles, Towers & Fixtures

Poles were first analyzed to determine their specific use. Those poles used for street lighting purposes were segmented to the Street Lighting segment and directly assigned to rates BPL and PSAL based upon the type of plant and number of each type being billed under each applicable rate. Although an analysis was performed to determine the portion of E364 directly related to providing service to customers on Rate HTS-HV, no assets were found.

The remaining pole investment was separated into three categories, based on its use, to deliver either secondary, primary and/or subtransmission voltages to customers. An analysis was performed utilizing the Graphic Information System ("GIS") facilities mapping system to determine the type and number of conductors attached to every distribution pole in the system.

The total investment in poles used to carry secondary voltage conductors was segmented to the Local Delivery segment and allocated to all secondary customers based upon the sum of individual secondary customer peak demands, consistent with the methodology previously explained. For pole configurations carrying conductors of several operating voltages, the appropriate secondary portion of the pole investment was segmented to the Local Delivery segment and allocated as stated above.

The portion of the investment in poles used to carry primary voltage conductors was segmented 50% to the Local Delivery segment and 50% to the System Delivery segment.

The plant segmented to the Local Delivery segment was allocated to all customers served at secondary or primary voltages based upon the sum of individual customer peak demands of these classes. Those investments segmented to the System Delivery segment were allocated to all customers served at secondary or primary voltages based on these classes' contribution to the system CP. To simplify modeling, a combined allocator named "PRIMARYLINES" was developed to perform this segmentation and allocation in one step.

Finally, the portion of the investment in poles used for carrying subtransmission voltage conductors was segmented 21.1% to the Local Delivery segment and 78.9% to the System Delivery segment, consistent with the methodology previously discussed. The subtransmission plant segmented to Local Delivery was directly assigned to Rate HTS-Subtransmission, while the investment segmented to System Delivery was allocated to customers served through non-Class H substations served at secondary, primary or subtransmission voltages based on these classes contribution to the system CP, consistent with the methodology previously discussed. Similar to what was done above, a combined allocator named "SUBTRANSLINES" was developed to perform this segmentation, assignment and allocation in one step.

E365 - Overhead Conductors and Devices

This account is comprised primarily of various types of wire and other overhead equipment of various plant types (i.e. #2 Al wire, #3 Al wire, 4kV single phase lighting arrestor, etc.).

The investment in conductors (wire) associated with dedicated street lighting poles (those used solely for street lighting) was first directly assigned to the Street Lighting segment in Rates PSAL or BPL based upon the number of overhead street lighting-only poles in each

rate class. This investment was estimated as the typical pole-to-pole length of secondary wire most commonly used for street lighting purposes for each of these street lighting poles.

The remaining equipment was first separated into the voltage class in which it is used - secondary, primary, subtransmission or high voltage and was then segmented and allocated in a method similar to that discussed above for poles. Investment in equipment whose normal operation voltage could not be determined or is used for all voltages (such as grounding wire) was allocated in the same proportion as the total of Account E365 equipment whose operating voltage could be determined.

The one exception to this method is the investment in conductors and other associated equipment used to serve customers on HTS-HV which was segmented to the Access segment since it effectively comprises the service drop to these customers. This investment was then directly assigned to this rate class. Although an analysis was performed to determine the portion of E365 directly related to providing service to customers on Rate HTS-HV, no assets were found.

E366 - Underground Conduit

These investments follow the functionalization and allocation of Account E367 underground Conductors and Devices.

E367 - Underground Conductors and Devices

A detailed segmentation and allocation was performed on a similar basis as done for investments booked to Account E365 - Overhead Conductors.

E368 - Line Transformers

Investments in line transformers were functionalized to the Local Delivery segment. The embedded costs of all line transformers in service were linked to the customers being served by each type and size of transformer. The average cost, in dollars per kVA, of

transformer capacity was multiplied by the sum of the peak demand of each customer class to arrive at a calculated total transformer investment by rate class. This value was then used as an allocator of booked transformer investment.

E369 - Services

Investment in electric services was first classified as either minimum or excess investment. This is done since the magnitude of the customer's use or peak demand in some cases requires the use of a larger size service wire. Since the increase in costs above that of the minimum sized service is driven by customer demands, they are more appropriately demand related costs. They are termed excess costs and are segmented to the Local Delivery Segment to be recovered through the rate component where other demand related costs are recovered. The minimum investment was determined for subsets of each rate class, as the installed cost of a service utilizing the minimum wire size installed for customers in that subclass. This portion was segmented to the Access Segment for recovery through the Service Charge. The subsets analyzed for Rate RS were comprised of the various type of housing stock, including single family detached, single family attached, two family, three to four family homes, five to nine family homes, and structures of ten or greater residential units. For the demand rates of GLP and LPL, the subsets were determined by electrical demand. The excess investment was determined as the additional cost, over the minimum cost, of the typical service utilizing the wire size most commonly installed for customers on each rate class subset.

E370 - Meters

Given that new AMI meters are relatively the same cost for customers in each rate class, the meter investment booked in FERC Account E370 was segmented to the Measurement segment and allocated across the rates based upon the relative installed cost of new meters.

E373 – Street Light and Signal Systems

The costs charged to this account include all street lighting luminaires, decorative street lighting poles, and miscellaneous devices such as shrouds and brackets. All costs related to street lighting luminaires and miscellaneous devices have been segmented to the Street Lighting segment and are directly assigned to the two street lighting Rate Schedules BPL and PSAL based upon the number and type of luminaires and other devices billed under each rate. Local municipalities are only charged for the luminaires used for public street lighting in overhead areas since the luminaires can be mounted on already existing distribution poles. Since this is not the case in declared underground zones, in order not to burden the municipality with the expense of the underground street lighting poles, standard underground poles have been provided at no charge. The investment related to these poles provided at no charge has been segmented and allocated in the same proportion as distribution plant excluding meters. The investment in poles for other than these purposes have been segmented to the Street Lighting Segment and directly assigned to the two street lighting Rate Schedules BPL and PSAL based upon the number and type of poles billed under each rate.

Asset Retirement Obligations

The amounts for Asset Retirement Obligations (or AROs) booked to Account E374 was found to be almost exclusively related to poles and towers booked to Account E364, thus were functionalized and allocated in the same proportion as performed for the plant in Account E364.

General, Common and Other Plant

An accounting code, or Business Code, associated with the actual gross plant balances indicating the department to which the plant is assigned was used to segment both the general

(Accounts E389 to E399) and common (Accounts C389 to C399) plant account items (Schedule SS-E5, page 1). Each Business Code was then grouped by function to be allocated based on cost causation. For example; a Description for office furniture and equipment was added to the Customer Service segment and allocated in the same proportion as all Customer Service activities. In other cases, where some of the facilities, such as vehicles, etc. used by the Customer Operations Department are shared between groups that are responsible for meter reading and those that provide general customer service (collections, phone inquiry, walk-in payment centers, etc.), these investments were further split in the Cost of Service Study between the Measurement segment and the Customer Service segment based on the proportion of work performed by each group. In general, all general and common investments were allocated to the rate schedules in the same proportion as the overall respective plant accounts for each segment. Items for which no reasonable functionalization could be determined were classified as "unassigned" and allocated in the same proportion as its associated plant account. In other words, unassigned general plant followed general plant and unassigned common plant followed common plant (general plant, common plant and other plant are shown on Schedule SS-E5, pages 11-12.

Depreciation Reserve

The depreciation reserve associated with each Account was segmented and allocated in the same proportion as its associated plant account (Schedule SS-E5, pages 15-18, lines 1 to 93).

Adjustments to Develop Rate Base

Adjustments to net plant used to develop Rate Base consist primarily of capital added since the end of the COS year, working capital and deferred taxes for the distribution utility.

Most capital additions used allocated based upon distribution plant with other additions allocated to total net plant. The capital rate base adjustment associated with the CEF-EC program were allocated based upon the underlying meter costs for the RS and GLP rate schedules. In addition, approximately $440M of distribution net plant additions associated with CEF-EC were reclassified into the CEF-EC adjustment, with a total CEF-EC adjustment of approximately $670 million. The underlying components of working capital were analyzed and segmented according to their individual use. Working capital requirements associated with Material and Supplies, Cash, Prepayments, and Working Funds were allocated and segmented in the same proportion as the sum of O&M and capital additions (essentially cash outlays) through the use of the allocator termed "EXPENDITURES." Deferred taxes were segmented and allocated in proportion to the related plant values. These adjustments are indicated in Schedule SS-E5, pages 19-20, lines 1 to 36.

Operating Revenues

The values indicated in Schedule SS-E5, pages 3-4, line 56 entitled "Rate Revenue from Customers" are the portion of the total target balanced revenue requirements necessary to be recovered from rate-related revenues (from service charges, distribution charges, minimum charges, etc.) at the proposed overall ROR, plus the increase in non-rate-related revenues. The effects of other non-rate-related revenues are booked to Accounts E450 to E456 and are shown in Schedule SS-E5, pages 21-22, lines 10 to 11.

Production Expenses

Similar to the production plant items, there are no production expenses (Accounts E500 to E557) remaining on the Company's books.

Transmission O&M Expenses

Similar to Transmission Plant, these items were excluded from the Cost of Service study.

Distribution O&M Expenses

O&M expenses (Accounts E580 to E598) were generally segmented and allocated in the same proportion as their associated plant account(s) (Schedule SS-E5, page 23-24, lines 14 to 48).

Customer Accounts, Service and Sales Expense

Expenses from a wide range of customer contact activities are booked to Accounts E901 to E916. A separate analysis was performed on the costs charged to each of these accounts to determine the best functionalization fit. The details of this account-by-account functionalization can be found on Schedule SS-E5, pages 25-28, lines 59 to 109. The costs in each of these accounts related to meter reading were segmented to the Measurement segment and allocated on the basis of the costs to read meters for each rate class. The portion related to billing was segmented to the Customer Service segment and allocated on the relative costs of billing by rate class. The portion related to account maintenance activities (including answering general questions, setting up new accounts, remittance processing, and collection activities) was segmented to the Customer Service segment and allocated on the relative costs of performing these activities by rate class. The portion of these expenses related to general regulated utility responsibilities was segmented to the Local Delivery segment and allocated on the relative costs of performing these activities by rate class. The portion of Customer Records and Collection costs (Account E903 and E905) associated with costs to disconnect

customers for non-payment of bills (and their eventual reconnection) were segmented to the Customer Service segment and allocated based upon the number of customers.

Where Customer Accounts expenses are recovered through the Societal Benefits Charge ("SBC"), such expenses were excluded from the Cost of Service study as indicated in Schedule SS-E3.

Administrative and General ("A&G") Expenses

These expenses (Accounts E920-935) include an eclectic mix of types of expenditures, which were analyzed separately to determine the best functionalization fit. The details of this item-by-item functionalization can be found on Schedule SS-E5, pages 27-28, lines 115 to 127.

Depreciation and Amortization Expenses

All depreciation and amortization expenses were segmented and allocated in the same proportion as their associated plant accounts (Schedule SS-E5, pages 29-30, lines 1 to 29).

Pro Forma Expense Adjustments

The pro forma adjustments the Company is proposing are summarized in Schedule MPM-29 and detailed as Adjustments #1 to #24 in Schedules MPM-30 through MPM 53of Mr. McFadden's direct testimony in this proceeding. With the exception of the pro forma adjustments discussed below, the balance of the adjustments related to electric distribution are included in the Cost of Service Study (Schedule SS-E5, pages 31-32, lines 11 to 45)

Each pro forma adjustment included in the Cost of Service Study was segmented and allocated in the same proportion as the associated plant or O&M account(s). The Cost of Service modeling of Pro-Forma #3 associated with Interest Synchronization, Pro-Forma #5 associated with Electric COLI Interest Expense, and Pro-Forma #7 associated with Gains and

Losses on Sales of Property all include the added income tax effects on revenue requirements as an additional expense.

Pro-Forma #6 associated with Weather Normalization, Pro-Forma #15 associated with Energy Strong II/IAP, Pro-Forma #19 associated with CEF-CE, Pro-Forma #21 associated with CIP, and Pro-Forma #22 associated with TAC are excluded from the Cost of Service Study (Schedule SS-E5) since these adjustments would be classified as revenue adjustments and do not impact distribution costs.

Taxes

All Taxes and Tax Deductions were segmented and allocated in the same proportion as their associated plant or O&M account(s). Details of these allocations are indicated on Page 35-44of Schedule SS-E5.

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also

contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	TBD	written	Dec-23	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E/G	QO23120874	written	Dec-23	Clean Energy Future - Energy Efficiency II Program
Public Service Electric & Gas Company	E/G	G018101112 and EO18101113	written	Nov-23	Clean Energy Future - Energy Efficiency Extension 2 Program
Public Service Electric & Gas Company	E	ER23110783	written	Nov-23	Infrastructure Advancement Program (IAP) - First Roll-In
Public Service Electric & Gas Company	E/G	ER23050273	written	Nov-23	Energy Strong II Program (Energy Strong II) - Fifth Roll-In
Public Service Electric & Gas Company	E/G	ER - 23090634 & GR - 23090635	written	Sep-23	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	GR23070448	written	Jul-23	COVID-19 Filing
Public Service Electric & Gas Company	E/G	ER23070423 & GR23070424	written	Jul-23	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, and CEF-EE
Public Service Electric & Gas Company	E	ER - ER23060412	written	Jul-23	SPRC 2023
Public Service Electric & Gas Company	G	GR23060330	written	Jun-23	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR23060332	written	Jun-23	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E	ER23050273	written	May-23	Energy Strong II Program (Energy Strong II) - Fourth Roll-In
Public Service Electric & Gas Company	G	GR23030102	written	Mar-23	Gas System Modernization Program III (GSMPIII)
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	Energy Strong II Program (Energy Strong II) - First Roll-In
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER18070688 & GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 & GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 & GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 & GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 & GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 & GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 & GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757 & GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389 & GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**RS**	**Delivery**			
2		Service Charges	23,773.073	23,773.073	0.00
3		kWhr 0-600 June - September	3,516,236	3,484,965	-31,270.79
4		kWhr 0-600 October - May	6,004,936	6,024,935	19,998.83
5		kWhr Over 600 June - September	1,966,770	1,921,436	-45,333.99
6		kWhr Over 600 October - May	1,608,581	1,613,017	4,436.61
7		Total kWhrs	13,096,522	13,044,353	-52,169.34
8					
9		**Supply**			
10		BGS 0-600 June - September	3,361,440	3,331,905	-29,534.46
11		BGS 0-600 October - May	5,888,311	5,906,859	18,548.02
12		BGS Over 600 June - September	1,894,417	1,850,958	-43,458.77
13		BGS Over 600 October - May	1,575,510	1,579,452	3,942.62
14		Total BGS	12,719,677	12,669,174	-50,502.58
15					
16					
17	**RHS**	**Delivery**			
18		Service Charges	76.845	76.845	0.00
19		kWhr 0-600 June - September	12,550	12,457	-93.32
20		kWhr 0-600 October - May	24,818	24,996	178.07
21		kWhr Over 600 June - September	5,998	5,908	-89.84
22		kWhr Over 600 October - May	39,623	39,681	57.48
23		Total kWhrs	82,990	83,042	52.40
24					
25		**Supply**			
26		BGS 0-600 June - September	11,163	11,087	-76.21
27		BGS 0-600 October - May	24,173	24,333	159.92
28		BGS Over 600 June - September	6,501	6,414	-86.39
29		BGS Over 600 October - May	39,080	39,142	62.86
30		Total BGS	80,916	80,976	60.17

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

Exhibit P-9E
Schedule SS-E2
Page 2 of 7

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**RLM**	**Delivery**			
2		Service Charges	134.368	134.368	0.00
3		kWhr June - September On-Peak	37,548	37,120	-428.36
4		kWhr June - September Off-Peak	41,034	40,625	-409.75
5		kWhr October - May On-Peak	42,718	42,872	153.88
6		kWhr October - May Off-Peak	56,161	56,348	186.77
7		Total kWhrs	177,462	176,965	-497.47
8					
9		**Supply**			
10		BGS June - September On-Peak	35,282	34,909	-372.48
11		BGS June - September Off-Peak	42,021	42,136	115.11
12		BGS October - May On-Peak	38,709	38,361	-347.42
13		BGS October - May Off-Peak	55,172	55,311	138.78
14		Total BGS	171,183	170,717	-466.01
15					
16					
17	**WH**	**Delivery**			
18		kWhr June - September	157	157	0.00
19		kWhr October - May	366	366	0.06
20		Total kWhrs	523	523	0.07
21					
22		**Supply**			
23		BGS June - September	155	155	0.00
24		BGS October - May	360	360	0.06
25		Total BGS	515	515	0.06
26					
27					
28	**WHS**	**Delivery**			
29		Service Charges	0.129	0.129	0.00
30		kWhr June - September	1.895	1.895	0.00
31		kWhr October - May	6.318	6.318	0.00
32		Total kWhrs	8.213	8.213	0.00
33					
34		**Supply**			
35		BGS June - September	1.895	1.895	0.00
36		BGS October - May	6.318	6.318	0.00
37		Total BGS	8.213	8.213	0.00

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**HS**	**Delivery**			
2		Service Charges	8.568	8.568	0.00
3		kWhr June - September	2,414	2,391	-22.85
4		kWhr October - May	7,927	7,960	32.44
5		Total kWhrs	10,341	10,350	9.60
6					
7		**Supply**			
8		BGS June - September	1,944	1,931	-13.42
9		BGS October - May	5,949	5,969	19.90
10		Total BGS	7,893	7,899	6.47
11					
12					
13	**GLP**	**Delivery**			
14		Service Charges	3,382.856	3,382.856	0.00
15		Annual Demand	26,346	26,280	-66.23
16		June - September Demand	9,772	9,697	-75.53
17		kWhr Other - June - September	2,603,595	2,583,201	-20,394.19
18		kWhr Other - October - May	4,476,412	4,478,018	1,605.87
19		kWhr Night Use - June - September	4,798	4,755	-43.08
20		kWhr Night Use - October - May	18,050	18,053	3.10
21		Total kWhrs	7,102,855	7,084,026	-18,828.29
22					
23		**Supply**			
24		Generation Capacity Obl - June - Septeml	6,834	6,788	-45.53
25		Generation Capacity Obl - October - May	12,568	12,573	4.86
26		Transmission Capacity Obl	17,497	17,460	-36.91
27		BGS June - September	1,892,199	1,877,715	-14,484.16
28		BGS October - May	3,362,114	3,363,254	1,140.63
29		BGS Night Use - June - September	3,358	3,327	-31.29
30		BGS Night Use - October - May	13,550	13,552	2.03
31		Total BGS	5,271,221	5,257,848	-13,372.79

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**LPL-S**	**Delivery**			
2		Service Charges	112.550	112.550	0.00
3		Annual Demand	25,488	25,474	-14.57
4		June - September Demand	9,219	9,172	-47.49
5		kWhr On-Peak - June - September	1,736,526	1,726,736	-9,789.82
6		kWhr Off-Peak - June - September	1,872,589	1,862,245	-10,344.54
7		kWhr On-Peak - October - May	3,306,817	3,312,787	5,970.73
8		kWhr Off-Peak - October - May	3,292,913	3,299,199	6,286.01
9		Total kWhrs	10,208,845	10,200,967	-7,877.62
10					
11		**Supply**			
12		**Peak Load Share 0 - 499**			
13		Generation Capacity Obl - June - Septeml	2,776	2,770	-6.05
14		Generation Capacity Obl - October - May	5,502	5,507	5.50
15		Transmission Capacity Obl	7,171	7,170	-0.60
16		BGS On-Peak - June - September	995,323	986,692	-8,631.66
17		BGS Off-Peak - June - September	570,003	567,722	-2,280.92
18		BGS On-Peak - October - May	2,094,550	2,096,520	1,970.09
19		BGS Off-Peak - October - May	1,096,054	1,097,057	1,003.30
20		Total BGS	4,755,930	4,747,990	-7,939.19
21					
22		**Peak Load Share 500+**			
23		Generation Capacity Obl - June - Septeml	561	560	-1.21
24		Generation Capacity Obl - October - May	1,426	1,427	1.12
25		Transmission Capacity Obl	1,760	1,760	-0.05
26		BGS June - September	258,582	257,776	-805.62
27					
28		BGS October - May	565,696	566,163	467.39
29					
30		Total BGS	824,278	823,939	-338.23

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**LPL-P**	**Delivery**			
2		Service Charges	9.366	9.366	0.00
3		Annual Demand	6,546	6,546	0.00
4		June - September Demand	2,456	2,456	0.00
5		kWhr On-Peak - June - September	500,122	500,122	0.00
6		kWhr Off-Peak - June - September	610,161	610,161	0.00
7		kWhr On-Peak - October - May	867,288	867,288	0.00
8		kWhr Off-Peak - October - May	967,215	967,215	0.00
9		Total kWhrs	2,944,785	2,944,785	0.00
10					
11		**Supply**			
12		Generation Capacity Obl - June - Septeml	485	485	0.00
13		Generation Capacity Obl - October - May	1,050	1,050	0.00
14		Transmission Capacity Obl	1,354	1,354	0.00
15		BGS June - September	116,282	116,282	0.00
16					
17		BGS October - May	123,903	123,903	0.00
18					
19		Total BGS	240,184	240,184	0.00
20					
21					
22	**HTS-S**	**Delivery**			
23		Service Charges	2.273	2.273	0.00
24		Annual Demand	11,771	11,771	0.00
25		June - September Demand	3,240	3,240	0.00
26		kWhr June - September	2,062,613	2,062,613	0.00
27					
28		kWhr October - May	2,478,938	2,478,938	0.00
29					
30		Total kWhrs	4,541,551	4,541,551	0.00
31					
32		**Supply**			
33		Generation Capacity Obl - June - Septeml	493	493	0.00
34		Generation Capacity Obl - October - May	947	947	0.00
35		Transmission Capacity Obl	1,258	1,258	0.00
36		BGS June - September	304,415	304,415	0.00
37					
38		BGS October - May	548,841	548,841	0.00
39					
40		Total BGS	853,255	853,255	0.00

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**HTS-HV**	**Delivery**			
2		Service Charges	0.196	0.196	0.00
3		Annual Demand	3,165	3,165	0.00
4		kWhr June - September	197,731	197,731	0.00
5					
6		kWhr October - May	238,260	238,260	0.00
7					
8		Total kWhrs	435,991	435,991	0.00
9					
10		**Supply**			
11		Generation Capacity Obl - June - Septeml	1	1	0.00
12		Generation Capacity Obl - October - May	5	5	0.00
13		Transmission Capacity Obl	6	6	0.00
14		BGS June - September	16,311	16,311	0.00
15					
16		BGS October - May	7,839	7,839	0.00
17					
18		Total BGS	24,149	24,149	0.00
19					
20					
21	**BPL**	**Delivery**			
22		Lamp Charge:			
23		High Pressure Sodium	2,220.312	2,220.312	0.00
24		Metal Halide	285.516	285.516	0.00
25		Incandescent	142.200	142.200	0.00
26		Mercury Vapor	1,881.180	1,881.180	0.00
27		Fluorescent	-	-	0.00
28		Pole Charge	497.880	497.880	0.00
29		kWhr June - September	75,127	75,127	0.00
30		kWhr October - May	210,786	210,786	0.00
31		Total kWhrs	285,913	285,913	0.00
32					
33		**Supply**			
34		BGS June - September	61,732	61,732	0.00
35		BGS October - May	206,107	206,107	0.00
36		Total BGS	267,840	267,840	0.00

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

			Actual Determinants	Weather Normalized (WN) Determinants	Variation From WN
1	**BPL-POF**	**Delivery**			
2		Lamp Charge:			
3		High Pressure Sodium	124.548	124.548	0.00
4		Metal Halide	1.476	1.476	0.00
5		Incandescent	6.048	6.048	0.00
6		Mercury Vapor	4.140	4.140	0.00
7		Fluorescent	0.024	0.024	0.00
8		Pole Charge	-	-	0.00
9		kWhr June - September	3,632	3,632	0.00
10		kWhr October - May	10,661	10,661	0.00
11		Total kWhrs	14,294	14,294	0.00
12					
13		**Supply**			
14		BGS June - September	3,513	3,513	0.00
15		BGS October - May	10,612	10,612	0.00
16		Total BGS	14,125	14,125	0.00
17					
18					
19	**PSAL**	**Delivery**			
20		Lamp Charge:			
21		High Pressure Sodium	720.168	720.168	0.00
22		Metal Halide	175.692	175.692	0.00
23		Incandescent	0.792	0.792	0.00
24		Mercury Vapor	241.980	241.980	0.00
25		Fluorescent	-	-	0.00
26		Pole Charge	361.188	361.188	0.00
27		kWhr June - September	36,506	36,506	0.00
28		kWhr October - May	100,676	100,676	0.00
29		Total kWhrs	137,182	137,182	0.00
30					
31		**Supply**			
32		BGS June - September	32,074	32,074	0.00
33		BGS October - May	99,317	99,317	0.00
34		Total BGS	131,391	131,391	0.00

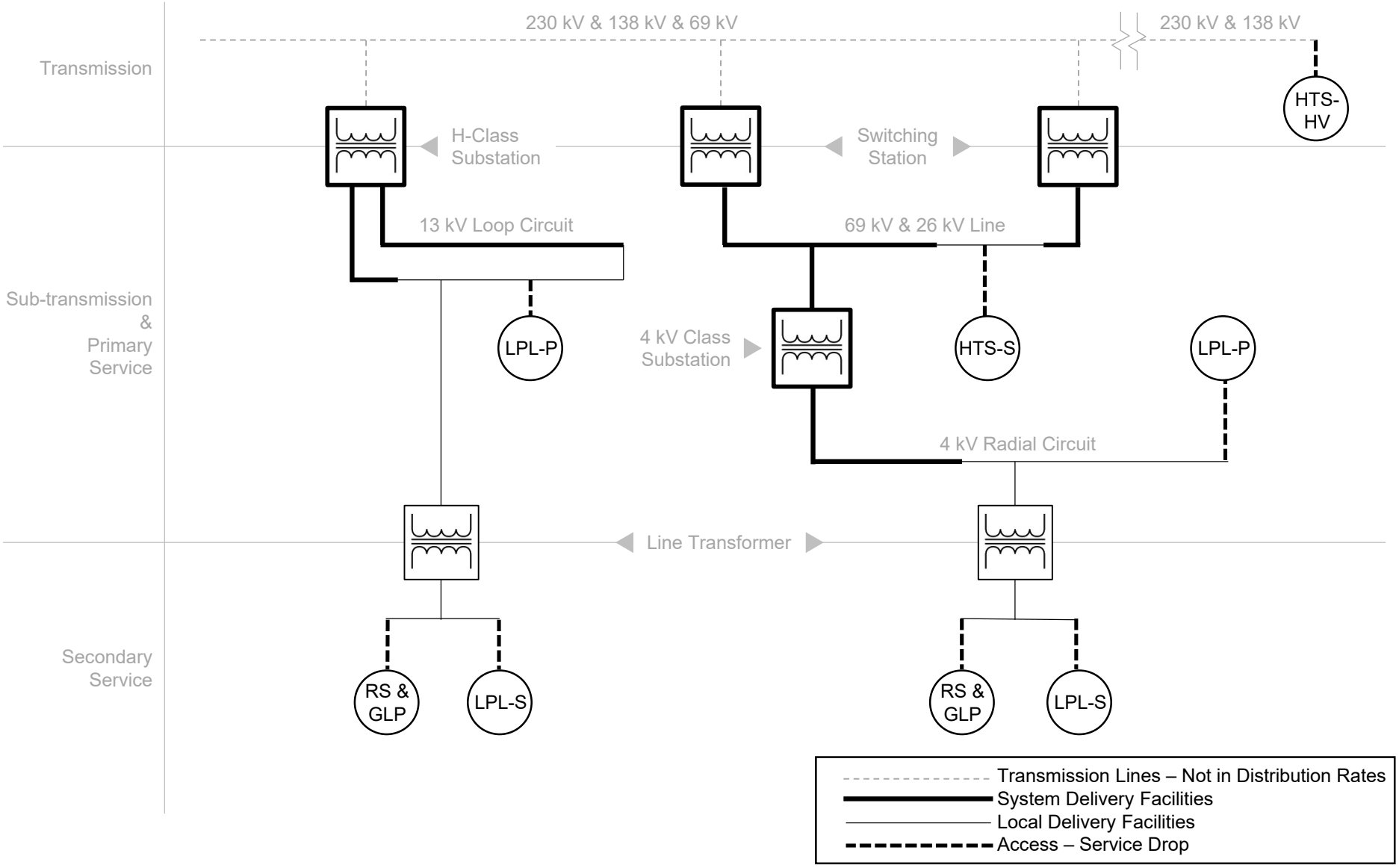
COS Adjustments

Listing of plant and expense items listed in the BPU Report but not included in the COS modeling for reasons as indicated

line	FERC Account		Amount	Related to:
	Expenses			
1	E555 & E556 - Power supply expenses	$	1,882,177,949	BGS, NGC, & ZEC
3	E904 - Uncollectible Accounts	$	74,356,162	SBC
4	E905 - Misc Customer Accounts	$	132,818,250	USF/Lifeline
5	E908 - DSM Amortization	$	141,442,126	DSM Amortization
	Amortizations			
7	E407.3 - RAC Amortization	$	24,795,430	RAC Amortization
8	E908 - BRC Amortization	$	48,257,435	E-BRC Amortization
	Interest Charges			
9	E431 - Expense on Clauses	$	1,682,922	Interest Expense on all clauses
	Current Tax Adjustments & Deductions			
10	CECL Reserve	$	(158,427)	CECL
11	COVID Deferrals	$	(2,144,328)	COVID
12	Clause - Deferred Fuel	$	(542,814)	BGS
13	Clause - RAC (Environmental Clean Up)	$	1,574,751	RAC
14	Clause - Societal Benefits Clause (AAP)	$	624,526	SBC
15	Clause - Demographic Studies	$	5,963	GPRC
16	Clause - Navigant Studies	$	46,365	GPRC
	Deferred Taxes			
17	CECL Reserve	$	158,427	CECL
18	COVID Deferrals	$	2,144,328	COVID
19	Clause - Deferred Fuel	$	542,814	BGS
20	Clause - RAC (Environmental Clean Up)	$	(1,574,751)	RAC
21	Clause - Societal Benefits Clause (AAP)	$	(624,526)	SBC
22	Clause - Demographic Studies	$	(5,963)	GPRC

Exhibit P-9E
Schedule SS-E4

Graphical Representation of Electrical System Layout and Illustration of 2022 Electric COS Segmentation Methodology



PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	S	**SUMMARY OF RESULTS**									
2	S	**DEVELOPMENT OF RETURN**									
3	S										
4	S	**RATE BASE**									
5	S	Plant in Service									
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0
8	S	Distribution Plant									
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	145,535,507	607,179	1,456,815	3,366	53	157,829	4,855,885
10	S	Station Equipment E362	CALCULATED	1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
13	S	UG Conductors E366	CALCULATED	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
15	S	Line Transformers E368	CALCULATED	1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
16	S	Services E369	CALCULATED	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
17	S	Meters E370	CALCULATED	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
18	S	Street Lighting E373	CALCULATED	499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	51,017,258	251,306	464,200	0	0	106,222	967,449
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
22	S	General Plant E389-E399	CALCULATED	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
23	S	Common Plant C389-C399	CALCULATED	126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	94,841,006	329,148	554,187	9,288	143	12,483	295,763
25	S	Total Plant in Service	CALCULATED	11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792
26	S										
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
28	S	Plus: Rate Base Additions									
29	S	Working Capital	CALCULATED	1,153,424,258	647,765,319	2,982,162	5,290,124	74,217	1,156	779,257	45,243,131
30	S	Plant Held for Future Use	CALCULATED	495,177	269,300	1,359	2,361	12	0	381	17,101
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,015,996,645	1,314,684,464	5,574,173	9,575,147	532,576	8,308	1,261,119	47,356,070
33	S	Plus: Rate Base Deductions									
34	S	Customer Advances	CALCULATED	-63,735,780	-36,212,594	-168,905	-299,200	-4,529	-71	-43,798	-2,156,744
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,800,404,102	-979,179,343	-4,940,307	-8,584,018	-43,922	-685	-1,386,500	-62,169,366
37	S	Other Rate Base Deductions		-27,893,945	-14,720,401	-66,521	-141,432	0	0	-25,826	-66,923
38	S										
39	S	TOTAL RATE BASE		9,635,540,505	5,433,120,523	26,081,061	45,565,460	729,937	11,384	7,045,925	326,456,069
40	S										
41	S										
42	S										
43	S										
44	S										
45	S										
46	S										
47	S										
48	S										
49	S										
50	S	**SUMMARY OF RESULTS**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	9,992	1,494,083	64,215,985	50,674,255	12,335,104	12,212,381	12,182
10	S	Station Equipment E362	CALCULATED	0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
12	S	OH Conductors and Devices E365	CALCULATED	220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
13	S	UG Conductors E366	CALCULATED	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
14	S	UG Conduits and Devices E367	CALCULATED	150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
15	S	Line Transformers E368	CALCULATED	224,770	2,148,246	222,857,213	207,839,938	0	0	0
16	S	Services E369	CALCULATED	0	0	173,970,914	12,601,784	1,049,662	579,957	0
17	S	Meters E370	CALCULATED	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
18	S	Street Lighting E373	CALCULATED	4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
19	S	Asset Retirement Obligations E374	CALCULATED	9,786	271,155	18,471,153	15,009,373	3,875,476	6,069,146	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
22	S	General Plant E389-E399	CALCULATED	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
23	S	Common Plant C389-C399	CALCULATED	6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	5,100	1,292,845	22,313,239	6,548,658	556,111	148,132	17,792
25	S	Total Plant in Service	CALCULATED	821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	466,745	16,746,702	216,687,907	153,380,805	33,854,976	29,888,817	262,941
30	S	Plant Held for Future Use	CALCULATED	36	5,352	97,066	71,569	15,823	14,774	42
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		105,536	14,678,219	341,008,608	196,653,895	43,618,007	40,825,895	114,629
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-17,170	-766,255	-11,942,471	-8,553,824	-1,871,130	-1,692,896	-6,193
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-129,172	-19,457,858	-352,927,893	-260,195,453	-57,525,502	-53,709,906	-154,177
37	S	Other Rate Base Deductions		-2,154	-85,062	-5,892,049	-4,804,994	-1,234,773	-853,810	0
38	S									
39	S	TOTAL RATE BASE		1,022,124	103,915,941	1,816,712,160	1,311,785,994	290,219,052	272,047,354	827,520
40	S									
41	S									
42	S									
43	S									
44	S									
45	S									
46	S									
47	S									
48	S									
49	S									
50	S	**SUMMARY OF RESULTS**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED								
52	S										
53	S	**RATE BASE**	CALCULATED	9,635,540,505	5,433,120,523	26,081,061	45,565,460	729,937	11,384	7,045,925	326,456,069
54	S										
55	S	**OPERATING REVENUES**									
56	S	Rate Revenues from Customers	CALCULATED	1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
57	S	Other Operating Revenues	CALCULATED	25,104,439	12,164,111	56,737	100,504	1,521	24	21,218	724,468
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		1,887,985,784	1,070,592,616	4,993,518	8,845,571	133,897	2,086	1,301,354	63,762,201
61	S										
62	S	**OPERATING EXPENSES**									
63	S	Operation and Maintenance Expense									
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
67	S	Customer Accounts Expense	CALCULATED	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
68	S	Customer Service & Information Expense	CALCULATED	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
69	S	Sales Expense	CALCULATED	40,922	29,919	96	204	2	0	14	205
70	S	Administrative and General Expense	CALCULATED	33,695,393	16,329,425	120,025	198,920	-1,682	-26	47,194	1,018,014
71	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	174,029,579	750,500	1,425,184	12,768	198	187,534	10,354,358
72	S	Depreciation Expense	CALCULATED	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
73	S	Amortization Expense	CALCULATED	21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
74	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-7,187,896	-27,957	-50,680	-1,041	-16	-4,982	-442,314
75	S	Proforma Expense Adjustments	CALCULATED	83,562,007	55,148,025	220,712	385,145	26,925	419	43,826	2,246,292
76	S	State Income Taxes	CALCULATED	116,400,498	64,842,495	315,649	551,521	7,312	114	86,720	4,008,952
77	S	Federal Income Taxes	CALCULATED	224,324,936	125,251,233	607,589	1,062,229	14,984	234	166,606	7,726,100
78	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	86,707,881	358,981	646,425	11,131	173	75,184	5,647,513
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		1,176,882,895	669,628,321	3,068,735	5,482,840	80,027	1,246	781,365	39,669,743
82	S										
83	S	**OPERATING INCOME (RETURN)**		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458
86	S										
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S										
90	S	**EQUALIZED RETURN AT PROPOSED ROR**									
91	S										
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**									
93	S										
94	S	**RATE BASE**	CALCULATED	9,635,540,505	5,433,120,523	26,081,061	45,565,460	729,937	11,384	7,045,925	326,456,069
95	S										
96	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
97	S										
98	S	**RETURN (RATE BASE * 7.40% ROR)**		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458
99	S	**PLUS:**	CALCULATED								
100	S	**OPERATING EXPENSES**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED							
52	S									
53	S	**RATE BASE**	CALCULATED	1,022,124	103,915,941	1,816,712,160	1,311,785,994	290,219,052	272,047,354	827,520
54	S									
55	S	**OPERATING REVENUES**								
56	S	Rate Revenues from Customers	CALCULATED	501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
57	S	Other Operating Revenues	CALCULATED	5,768	371,208	5,785,460	4,143,850	906,458	820,114	3,000
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		507,620	22,767,438	354,842,239	254,156,637	55,596,191	50,300,403	184,015
61	S									
62	S	**OPERATING EXPENSES**								
63	S	Operation and Maintenance Expense								
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
67	S	Customer Accounts Expense	CALCULATED	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
68	S	Customer Service & Information Expense	CALCULATED	214	34,498	876,964	140,606	11,945	3,040	367
69	S	Sales Expense	CALCULATED	4	555	9,167	677	61	17	1
70	S	Administrative and General Expense	CALCULATED	6,330	113,201	8,621,889	3,552,196	1,801,552	1,887,742	613
71	S	Total Operation and Maintenance Expense	CALCULATED	364,091	5,252,980	59,033,027	42,782,536	9,532,172	7,696,917	35,792
72	S	Depreciation Expense	CALCULATED	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
73	S	Amortization Expense	CALCULATED	1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
74	S	Taxes Other Than Income Taxes	CALCULATED	-685	-184,390	-1,945,365	-1,294,579	-233,700	-176,085	-1,528
75	S	Proforma Expense Adjustments	CALCULATED	4,027	829,030	13,749,170	7,905,781	1,602,824	1,382,943	16,888
76	S	State Income Taxes	CALCULATED	11,428	1,262,650	22,143,408	16,202,860	3,589,532	3,368,164	9,692
77	S	Federal Income Taxes	CALCULATED	22,629	2,433,950	42,543,851	31,109,796	6,894,291	6,472,752	18,693
78	S	Provision for Deferred Income Taxes	CALCULATED	9,081	2,180,600	25,157,397	17,579,324	3,389,115	2,745,219	17,592
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		432,187	15,098,442	220,768,881	157,346,831	34,178,025	30,223,309	122,944
82	S									
83	S	**OPERATING INCOME (RETURN)**		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071
86	S									
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S									
90	S	**EQUALIZED RETURN AT PROPOSED ROR**								
91	S									
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**								
93	S									
94	S	**RATE BASE**	CALCULATED	1,022,124	103,915,941	1,816,712,160	1,311,785,994	290,219,052	272,047,354	827,520
95	S									
96	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
97	S									
98	S	**RETURN (RATE BASE * 7.40% ROR)**		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071
99	S	**PLUS:**	CALCULATED							
100	S	**OPERATING EXPENSES**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	174,029,579	750,500	1,425,184	12,768	198	187,534	10,354,358
102	S	Depreciation Expense	CALCULATED	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
103	S	Amortization Expense	CALCULATED	21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
104	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-7,187,896	-27,957	-50,680	-1,041	-16	-4,982	-442,314
105	S	Proforma Expense Adjustments	CALCULATED	83,562,007	55,148,025	220,712	385,145	26,925	419	43,826	2,246,292
106	S	Income Taxes	CALCULATED	340,725,434	190,093,728	923,238	1,613,750	22,297	348	253,326	11,735,052
107	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	86,707,881	358,981	646,425	11,131	173	75,184	5,647,513
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		1,176,882,895	669,628,321	3,068,735	5,482,840	80,027	1,246	781,365	39,669,743
111	S										
112	S	**EQUALS TOTAL COST OF SERVICE**		1,887,985,784	1,070,592,616	4,993,518	8,845,571	133,897	2,086	1,301,354	63,762,201
113	S										
114	S	**LESS:**									
115	S	Other Operating Revenues	CALCULATED	25,104,439	12,164,111	56,737	100,504	1,521	24	21,218	724,468
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0
118	S	**EQUALS:**									
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
120	S										
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	S	Total Operation and Maintenance Expense	CALCULATED	364,091	5,252,980	59,033,027	42,782,536	9,532,172	7,696,917	35,792
102	S	Depreciation Expense	CALCULATED	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
103	S	Amortization Expense	CALCULATED	1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
104	S	Taxes Other Than Income Taxes	CALCULATED	-685	-184,390	-1,945,365	-1,294,579	-233,700	-176,085	-1,528
105	S	Proforma Expense Adjustments	CALCULATED	4,027	829,030	13,749,170	7,905,781	1,602,824	1,382,943	16,888
106	S	Income Taxes	CALCULATED	34,057	3,696,600	64,687,259	47,312,656	10,483,823	9,840,916	28,384
107	S	Provision for Deferred Income Taxes	CALCULATED	9,081	2,180,600	25,157,397	17,579,324	3,389,115	2,745,219	17,592
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		432,187	15,098,442	220,768,881	157,346,831	34,178,025	30,223,309	122,944
111	S									
112	S	**EQUALS TOTAL COST OF SERVICE**		507,620	22,767,438	354,842,239	254,156,637	55,596,191	50,300,403	184,015
113	S									
114	S	**LESS:**								
115	S	Other Operating Revenues	CALCULATED	5,768	371,208	5,785,460	4,143,850	906,458	820,114	3,000
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
118	S	**EQUALS:**								
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
120	S									
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBP	**DEVELOPMENT OF RATE BASE**									
2	RBP										
3	RBP	**ELECTRIC PLANT IN SERVICE**									
4	RBP										
5	RBP	PRODUCTION PLANT									
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0
9	RBP										
10	RBP	TRANSMISSION PLANT									
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	RBP										
18	RBP	DISTRIBUTION PLANT									
19	RBP	E360-E361 Land & Structures									
20	RBP	E360 - Land and Land Rights									
21	RBP	- Headquarters related	DISTPLT	14,080,608	7,606,431	38,672	67,232	343	5	11,019	494,440
22	RBP	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	16,983,975	54,520	190,989	0	0	11,896	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0	0
26	RBP	- Headquarters related	DISTPLT	124,204,880	67,096,238	341,129	593,052	3,023	47	97,197	4,361,446
27	RBP	- Substation related	E362PLT	118,051,566	53,848,863	172,858	605,542	0	0	37,717	0
28	RBP	Total Accounts E360-E361		293,570,614	145,535,507	607,179	1,456,815	3,366	53	157,829	4,855,885
29	RBP	E362 - Station Equipment									
30	RBP	Switching Stations	CP_SUBT_05	338,443,408	123,925,080	397,808	1,393,565	0	0	86,801	0
31	RBP	H Class Substations	CP_PRI_05	1,226,974,761	590,135,661	1,894,375	6,636,207	0	0	413,348	0
32	RBP	4 kV Class Substations	CP_PRI_05	0	0	0	0	0	0	0	0
33	RBP	Total Account E362		1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
34	RBP	E364 - Poles Towers & Fixtures									
35	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	0	0	0	0	0	0	8,114,160
36	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	0	0	0	0	0	0	0
37	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
38	RBP	Subtransmission lines	SUBTRANSLINES	101,446,395	29,308,040	94,081	329,575	0	0	20,528	0
39	RBP	Primary lines	PRIMARYLINES	482,404,572	263,513,493	1,191,442	2,531,024	0	0	462,818	810,202
40	RBP	Secondary lines	SUMPK_SEC_04	433,665,531	250,292,946	1,389,803	2,081,139	0	0	647,459	1,374,806
41	RBP	Total Account E364		1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
42	RBP										
43	RBP										
44	RBP										
45	RBP										
46	RBP										
47	RBP										
48	RBP										
49	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
50	RBP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	DISTPLT	1,017	152,132	2,765,379	2,058,144	457,036	427,519	1,240
22	RBP	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	0	0	8,885,414	7,303,859	1,881,413	1,921,495	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	DISTPLT	8,975	1,341,952	24,393,375	18,154,863	4,031,507	3,771,136	10,941
27	RBP	- Substation related	E362PLT	0	0	28,171,817	23,157,389	5,965,148	6,092,231	0
28	RBP	Total Accounts E360-E361		9,992	1,494,083	64,215,985	50,674,255	12,335,104	12,212,381	12,182
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations	CP_SUBT_05	0	0	64,833,210	53,293,256	13,727,893	80,785,795	0
31	RBP	H Class Substations	CP_PRI_05	0	0	308,738,062	253,784,389	65,372,719	0	0
32	RBP	4 kV Class Substations	CP_PRI_05	0	0	0	0	0	0	0
33	RBP	Total Account E362		0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
34	RBP	E364 - Poles Towers & Fixtures								
35	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	0	0	0	0	0	0	0
36	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	0	1,812,825	0	0	0	0	0
37	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
38	RBP	Subtransmission lines	SUBTRANSLINES	0	0	15,332,928	12,603,751	3,246,620	40,510,872	0
39	RBP	Primary lines	PRIMARYLINES	38,630	398,171	105,415,923	85,965,553	22,077,315	0	0
40	RBP	Secondary lines	SUMPK_SEC_04	65,550	675,644	75,889,522	61,215,998	15,933,226	24,099,439	0
41	RBP	Total Account E364		104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
42	RBP									
43	RBP									
44	RBP									
45	RBP									
46	RBP									
47	RBP									
48	RBP									
49	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
50	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBP	DISTRIBUTION PLANT CONTINUED									
52	RBP	E365 - OH Conductors and Devices									
53	RBP	Direct - BPL	DIR_BPL_02	2,226,625	0	0	0	0	0	0	2,226,625
54	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	0	0	0	0	0	0	0
55	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
56	RBP	Subtransmission lines	SUBTRANSLINES	201,889,270	58,326,161	187,231	655,891	0	0	40,853	0
57	RBP	Primary lines	PRIMARYLINES	2,523,188,742	1,378,291,830	6,231,765	13,238,372	0	0	2,420,743	4,237,715
58	RBP	Secondary lines	SUMPK_SEC_04	122,443,422	70,669,035	392,404	587,600	0	0	182,807	388,170
59	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0
60	RBP	Total Account E365		2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
61	RBP										
62	RBP	E366 - Underground Conduit									
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
64	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
65	RBP	Underground Conduits	E367PLT	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
66	RBP	Not Used	not_used								
67	RBP	Total Account E366		512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
68	RBP										
69	RBP	E367 - Underground Conductors & Devices									
70	RBP	Direct - BPL	DIR_BPL_02	2,325,498	0	0	0	0	0	0	2,325,498
71	RBP	Direct - PSAL	DIR_PSAL_02	868,520	0	0	0	0	0	0	0
72	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	2,116,850	10,964	19,085	8	0	3,184	144,644
73	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
74	RBP	367.1 - Conventional UG									
75	RBP	Subtransmission lines	SUBTRANSLINES	51,391,650	14,847,137	47,660	166,959	0	0	10,399	0
76	RBP	Primary lines	PRIMARYLINES	354,073,350	193,412,565	874,490	1,857,711	0	0	339,697	594,669
77	RBP	Secondary lines	SUMPK_SEC_04	539,234,440	311,222,744	1,728,128	2,587,759	0	0	805,072	1,709,481
78	RBP	367.2 - BUD									
79	RBP	Subtransmission lines	SUBTRANSLINES	479,311	138,474	445	1,557	0	0	97	0
80	RBP	Primary lines	PRIMARYLINES	448,395,026	244,935,779	1,107,445	2,352,587	0	0	430,189	753,083
81	RBP	Secondary lines	SUMPK_SEC_04	30,436,220	17,566,467	97,541	146,062	0	0	45,441	96,489
82	RBP	Other	E367PLT	0	0	0	0	0	0	0	0
83	RBP	Total Account E367		1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
84	RBP										
85	RBP	E368 - Line Transformers									
86	RBP	Line Transformers	LNTRFRMR_04	1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
87	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
88	RBP	Total Account E368		1,591,690,631	1,136,331,766	8,618,064	7,219,368	0	0	1,519,865	4,931,400
89	RBP	E369 - Services									
90	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
91	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0
92	RBP	Total Account E369		535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
93	RBP										
94	RBP										
95	RBP										
96	RBP										
97	RBP										
98	RBP										
99	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0	0
100	RBP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBP	DISTRIBUTION PLANT CONTINUED								
52	RBP	E365 - OH Conductors and Devices								
53	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
54	RBP	Direct - PSAL	DIR_PSAL_02	0	6,436,532	0	0	0	0	0
55	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
56	RBP	Subtransmission lines	SUBTRANSLINES	0	0	30,514,180	25,082,824	6,461,124	80,621,006	0
57	RBP	Primary lines	PRIMARYLINES	202,052	2,082,611	551,371,787	449,637,769	115,474,097	0	0
58	RBP	Secondary lines	SUMPK_SEC_04	18,508	190,765	21,427,049	17,284,049	4,498,671	6,804,363	0
59	RBP	Other	DISTPLT	0	0	0	0	0	0	0
60	RBP	Total Account E365		220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
61	RBP									
62	RBP	E366 - Underground Conduit								
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
64	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
65	RBP	Underground Conduits	E367PLT	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
66	RBP	Not Used	not_used							
67	RBP	Total Account E366		53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
68	RBP									
69	RBP	E367 - Underground Conductors & Devices								
70	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
71	RBP	Direct - PSAL	DIR_PSAL_02	0	868,520	0	0	0	0	0
72	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	298	44,505	783,914	599,188	132,602	124,214	5
73	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
74	RBP	367.1 - Conventional UG								
75	RBP	Subtransmission lines	SUBTRANSLINES	0	0	7,767,496	6,384,924	1,644,703	20,522,371	0
76	RBP	Primary lines	PRIMARYLINES	28,353	292,248	77,372,752	63,096,648	16,204,218	0	0
77	RBP	Secondary lines	SUMPK_SEC_04	81,507	840,119	94,363,608	76,118,050	19,811,914	29,966,060	0
78	RBP	367.2 - BUD								
79	RBP	Subtransmission lines	SUBTRANSLINES	0	0	72,445	59,550	15,340	191,404	0
80	RBP	Primary lines	PRIMARYLINES	35,907	370,100	97,984,095	79,904,977	20,520,863	0	0
81	RBP	Secondary lines	SUMPK_SEC_04	4,601	47,419	5,326,202	4,296,361	1,118,252	1,691,386	0
82	RBP	Other	E367PLT	0	0	0	0	0	0	0
83	RBP	Total Account E367		150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
84	RBP									
85	RBP	E368 - Line Transformers								
86	RBP	Line Transformers	LNTRFRMR_04	224,770	2,148,246	222,857,213	207,839,938	0	0	0
87	RBP	Not Used	not_used	0	0	0	0	0	0	0
88	RBP	Total Account E368		224,770	2,148,246	222,857,213	207,839,938	0	0	0
89	RBP	E369 - Services								
90	RBP	Basic portion (minimum size)	SERVICESMIN_03	0	0	173,970,914	12,601,784	1,049,662	579,957	0
91	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
92	RBP	Total Account E369		0	0	173,970,914	12,601,784	1,049,662	579,957	0
93	RBP									
94	RBP									
95	RBP									
96	RBP									
97	RBP									
98	RBP									
99	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0
100	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	RBP	E370 - Meters		0	0	0	0	0	0	0	0
102	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0
103	RBP	Basic portion (minimum size)	METERSMIN_07	339,768,857	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
104	RBP	Excess portion	METERSEXC_04	25,652,585	0	0	0	0	0	0	0
105	RBP	Total Account E370		365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
106	RBP										
107	RBP	E371 - Installations on Customer Premises	not_used	0	0	0	0	0	0	0	0
108	RBP										
109	RBP	E373 - Street Lighting & Signal Systems									
110	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	0	0	0	0	0	0	340,539,607
111	RBP	PSAL luminaires & poles	DIR_PSAL_02	96,860,656	0	0	0	0	0	0	0
112	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	61,626,889	32,782,049	169,794	295,554	127	2	49,305	2,239,999
113	RBP	Total Account E373		499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
114	RBP										
115	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	51,017,258	251,306	464,200	0	0	106,222	967,449
116	RBP										
117	RBP	Other Distribution and Unallocated Plant									
118	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
119	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0
120	RBP										
121	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
122	RBP										
123	RBP	GENERAL AND COMMON PLANT									
124	RBP	E390-E398 GENERAL PLANT									
125	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0
126	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
127	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0
128	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
129	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
130	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0
131	RBP	Total Accounts E390-E398		429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
132	RBP										
133	RBP	C389-C399 COMMON PLANT									
134	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
135	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
136	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0	0
137	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
138	RBP	Customer Service Related	CUSTSVSX	92,605,476	69,239,577	239,965	404,005	6,821	105	8,885	205,542
139	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	17,947,041	92,957	161,805	69	1	26,993	1,226,322
140	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
141	RBP	Unassigned	COMPLT	309,972	213,904	817	1,388	17	0	88	3,513
142	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
143	RBP	Total Accounts C389-C399		126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
144	RBP										
145	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	315,915,436	1,517,329	2,627,425	7,792	120	379,660	17,049,812
146	RBP										
147	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
148	RBP										
149	RBP	INTANGIBLE PLANT - E301-E303									
150	RBP	Customer Service Related	CUSTSVSX	40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	RBP	E370 - Meters		0	0	0	0	0	0	0
102	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
103	RBP	Basic portion (minimum size)	METERSMIN_07	0	0	45,701,890	4,023,662	1,050,400	1,869,908	936,819
104	RBP	Excess portion	METERSEXC_04	0	0	19,886,346	3,577,553	1,827,189	361,497	0
105	RBP	Total Account E370		0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
106	RBP									
107	RBP	E371 - Installations on Customer Premises	not_used	0	0	0	0	0	0	0
108	RBP									
109	RBP	E373 - Street Lighting & Signal Systems								
110	RBP	BPL luminaires & poles	DIR_BPL_02	0	0	0	0	0	0	0
111	RBP	PSAL luminaires & poles	DIR_PSAL_02	0	96,860,656	0	0	0	0	0
112	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	4,609	689,214	12,139,877	9,279,168	2,053,508	1,923,610	73
113	RBP	Total Account E373		4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
114	RBP									
115	RBP	E374 - Asset Retirement Obligations	E364PLT	9,786	271,155	18,471,153	15,009,373	3,875,476	6,069,146	0
116	RBP									
117	RBP	Other Distribution and Unallocated Plant								
118	RBP	Not Used	not_used	0	0	0	0	0	0	0
119	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
120	RBP									
121	RBP	TOTAL DISTRIBUTION PLANT		778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
122	RBP									
123	RBP	GENERAL AND COMMON PLANT								
124	RBP	E390-E398 GENERAL PLANT								
125	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
126	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
127	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0
128	RBP	Distribution Delivery	DISTPLTXMTR	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
129	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
130	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
131	RBP	Total Accounts E390-E398		32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
132	RBP									
133	RBP	C389-C399 COMMON PLANT								
134	RBP	Not Used	not_used	0	0	0	0	0	0	0
135	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
136	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
137	RBP	Not Used	not_used	0	0	0	0	0	0	0
138	RBP	Customer Service Related	CUSTSVSX	3,745	952,052	16,257,022	4,778,271	398,336	98,019	13,129
139	RBP	Distribution Delivery Related	DISTPLTXMTR	2,523	377,321	6,646,164	5,080,024	1,124,225	1,053,110	40
140	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
141	RBP	Unassigned	COMPLT	15	3,261	56,191	24,186	3,735	2,824	32
142	RBP	Not Used	not_used	0	0	0	0	0	0	0
143	RBP	Total Accounts C389-C399		6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
144	RBP									
145	RBP	TOTAL GENERAL AND COMMON PLANT		38,413	6,136,963	107,583,221	74,565,084	15,840,751	14,562,921	13,708
146	RBP									
147	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
148	RBP									
149	RBP	INTANGIBLE PLANT - E301-E303								
150	RBP	Customer Service Related	CUSTSVSX	1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
152	RBP	TOTAL INTANGIBLE PLANT		40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080
153	RBP										
154	RBP	C303 - INTANGIBLE PLANT									
155	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
156	RBP	Meter Reading	MRCOST_07	1,212,800	954,739	3,317	5,542	63	1	75	0
157	RBP	Customer Service Related	CUSTSVSX	84,635,615	63,280,644	219,313	369,235	6,234	96	8,121	187,853
158	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
159	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
160	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
161	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	260,946	1,352	2,353	1	0	392	17,830
162	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	64,496,329	223,981	377,130	6,298	97	8,588	205,683
163	RBP										
164	RBP	TOTAL INTANGIBLE PLANT		126,923,895	94,841,006	329,148	554,187	9,288	143	12,483	295,763
165	RBP										
166	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	RBP	Not Used	not_used	0	0	0	0	0	0	0
152	RBP	TOTAL INTANGIBLE PLANT		1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754
153	RBP									
154	RBP	C303 - INTANGIBLE PLANT								
155	RBP	Not Used	not_used	0	0	0	0	0	0	0
156	RBP	Meter Reading	MRCOST_07	0	0	233,962	13,647	1,137	279	38
157	RBP	Customer Service Related	CUSTSVSX	3,422	870,116	14,857,902	4,367,041	364,055	89,583	12,000
158	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
159	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
160	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
161	RBP	E399.1 Asset Retirement Obligations	GENPLT	37	5,486	96,634	73,862	16,346	15,312	1
162	RBP	TOTAL ACCOUNTS C303-C390.4,E399		3,459	875,602	15,188,498	4,454,551	381,537	105,174	12,038
163	RBP									
164	RBP	TOTAL INTANGIBLE PLANT		5,100	1,292,845	22,313,239	6,548,658	556,111	148,132	17,792
165	RBP									
166	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**									
2	RBD										
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE									
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	11,781,979	40,833	68,747	1,161	18	1,512	34,976
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	11,781,979	40,833	68,747	1,161	18	1,512	34,976
8	RBD										
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
11	RBD										
12	RBD	DISTRIBUTION PLANT RESERVE									
13	RBD	E360-E361 Land & Structures - Reserve									
14	RBD	E360 - Land and Land Rights									
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	304,658	978	3,426	0	0	213	0
19	RBD	E361 - Structures and improvements									
20	RBD	- Headquarters Related	DISTPLT	40,449,681	21,851,166	111,095	193,139	985	15	31,654	1,420,388
21	RBD	- Substation Related	E362PLT	36,319,499	16,567,029	53,181	186,300	0	0	11,604	0
22	RBD	Total Accounts E360-E361		77,437,073	38,722,852	165,254	382,864	985	15	43,471	1,420,388
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	127,398,701	408,958	1,432,627	0	0	89,234	0
24	RBD	E364 Poles Towers and Fixtures Rsrv									
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	105,754,104	520,934	962,245	0	0	220,188	2,005,432
27	RBD	E365 OH Conductors and Devices - Rsrv									
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	321,912,606	1,454,717	3,092,904	0	0	564,768	1,463,496
30	RBD	E366 UG Conduit - Rsrv									
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	141,539,369	697,856	1,287,130	1	0	294,918	1,014,993
33	RBD	E367 UG Conductors and Devices - Rsrv									
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	280,997,427	1,385,450	2,555,334	3	0	585,500	2,015,061
36	RBD	E368 Line Transformers - Rsrv	LNTRFRMR_04	378,941,964	270,532,340	2,051,747	1,718,752	0	0	361,842	1,174,044
37	RBD	E369 Services - Rsrv									
38	RBD	Services	E369PLT	240,814,772	153,730,211	900,570	1,504,596	8,066	126	0	0
39	RBD	Not used	not_used	0	0	0	0	0	0	0	0
40	RBD	Total Accounts E369 Rsrv		240,814,772	153,730,211	900,570	1,504,596	8,066	126	0	0
41	RBD	E370 Meters - Rsrv									
42	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0
43	RBD	All other Meters	METERPLTXPR	136,921,647	106,188,362	342,124	571,591	90,235	1,408	38,858	0
44	RBD	Total Account E370 Rsrv		136,921,647	106,188,362	342,124	571,591	90,235	1,408	38,858	0
45	RBD	E371 - Installations on Cust Premises Rsrv	not_used	0	0	0	0	0	0	0	0
46	RBD	E373 Street Lighting - Rsrv									
47	RBD	Streetlight fixtures	E373PLT	118,939,285	7,813,349	40,469	70,443	30	0	11,752	81,698,884
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	7,813,349	40,469	70,443	30	0	11,752	81,698,884
50	RBD										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	637	162,004	2,766,335	813,083	67,782	16,679	2,234
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		637	162,004	2,766,335	813,083	67,782	16,679	2,234
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	0	0	159,386	131,016	33,749	34,468	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	2,923	437,032	7,944,166	5,912,476	1,312,937	1,228,142	3,563
21	RBD	- Substation Related	E362PLT	0	0	8,667,282	7,124,554	1,835,225	1,874,323	0
22	RBD	Total Accounts E360-E361		2,923	437,032	16,770,835	13,168,047	3,181,911	3,136,933	3,563
23	RBD	E362 Station Equipment - Rsrv	E362PLT	0	0	66,650,485	54,787,066	14,112,686	14,413,347	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	20,286	562,080	38,289,009	31,113,057	8,033,507	12,580,783	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	47,105	1,860,183	128,850,088	105,077,861	27,002,597	18,671,512	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	27,192	444,505	51,196,756	41,593,287	10,729,135	9,474,358	1
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	53,984	882,474	101,640,674	82,574,952	21,300,500	18,809,398	2
36	RBD	E368 Line Transformers - Rsrv	LNTRFRMR_04	53,512	511,444	53,056,761	49,481,522	0	0	0
37	RBD	E369 Services - Rsrv								
38	RBD	Services	E369PLT	0	0	78,268,571	5,669,474	472,237	260,919	0
39	RBD	Not used	not_used	0	0	0	0	0	0	0
40	RBD	Total Accounts E369 Rsrv		0	0	78,268,571	5,669,474	472,237	260,919	0
41	RBD	E370 Meters - Rsrv								
42	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
43	RBD	All other Meters	METERPLTXPR	0	0	24,575,595	2,848,138	1,078,219	836,097	351,021
44	RBD	Total Account E370 Rsrv		0	0	24,575,595	2,848,138	1,078,219	836,097	351,021
45	RBD	E371 - Installations on Cust Premises Rsrv	not_used	0	0	0	0	0	0	0
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	1,099	23,250,262	2,893,446	2,211,618	489,438	458,478	17
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		1,099	23,250,262	2,893,446	2,211,618	489,438	458,478	17
50	RBD									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**									
52	RBD	Other Plant Unallocated - Reserve									
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0
56	RBD										
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
60	RBD										
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	1,554,589,322	7,968,078	13,578,486	99,321	1,549	2,210,530	90,792,298
62	RBD										
63	RBD	GENERAL AND COMMON PLANT RESERVE									
64	RBD	E390-E398 GENERAL PLANT - RESERVE									
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	83,209,190	430,981	750,191	322	5	125,149	5,685,688
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	83,209,190	430,981	750,191	322	5	125,149	5,685,688
72	RBD										
73	RBD	C389-C399 COMMON PLANT RESERVE									
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0	0
77	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	34,978,355	121,225	204,095	3,446	53	4,489	103,836
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	10,200,490	52,833	91,965	39	1	15,342	697,000
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	45,178,845	174,059	296,060	3,485	54	19,831	800,836
84	RBD										
85	RBD	C303 - INTANGIBLE PLANT									
86	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
87	RBD	Meter Reading	MRCOST_07	623,486	490,820	1,705	2,849	33	1	39	0
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	34,819,759	120,676	203,169	3,430	53	4,468	103,365
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	260,946	1,352	2,353	1	0	392	17,830
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	35,571,526	123,732	208,371	3,464	53	4,900	121,195
94	RBD										
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
96	RBD										
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	4,500,513,778	22,699,101	39,722,478	171,583	2,675	6,461,292	298,232,800

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**								
52	RBD	Other Plant Unallocated - Reserve								
53	RBD	Not Used	not_used	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
56	RBD									
57	RBD	Not Used	not_used	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD									
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		206,100	27,947,981	562,192,220	388,525,022	86,400,229	78,641,825	354,604
62	RBD									
63	RBD	GENERAL AND COMMON PLANT RESERVE								
64	RBD	E390-E398 GENERAL PLANT - RESERVE								
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	11,699	1,749,401	30,814,100	23,552,891	5,212,326	4,882,611	184
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		11,699	1,749,401	30,814,100	23,552,891	5,212,326	4,882,611	184
72	RBD									
73	RBD	C389-C399 COMMON PLANT RESERVE								
74	RBD	Not Used	not_used	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
76	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0	0
77	RBD	Not Used	not_used	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	1,892	480,956	8,212,700	2,413,881	201,231	49,517	6,633
79	RBD	Distribution Delivery Related	DISTPLTXMTR	1,434	214,456	3,777,454	2,887,314	638,971	598,552	23
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		3,326	695,413	11,990,155	5,301,194	840,202	648,069	6,655
84	RBD									
85	RBD	C303 - INTANGIBLE PLANT								
86	RBD	Not Used	not_used	0	0	0	0	0	0	0
87	RBD	Meter Reading	MRCOST_07	0	0	120,277	7,016	584	144	19
88	RBD	Customer Service Related	CUSTSVSX	1,883	478,776	8,175,463	2,402,936	200,319	49,292	6,603
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	37	5,486	96,634	73,862	16,346	15,312	1
93	RBD	Total Accounts C303-C390.4,E399		1,920	484,262	8,392,374	2,483,814	217,249	64,748	6,623
94	RBD									
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
96	RBD									
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		598,304	92,794,843	1,629,680,992	1,235,233,997	273,361,651	257,574,480	610,278

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
2	RBO										
3	RBO	**PLUS: ADDITIONS TO RATE BASE**									
4	RBO										
5	RBO	Working Capital									
6	RBO	Cash (lead/lag)	EXPENDITURES	925,712,100	519,881,726	2,393,415	4,245,733	59,565	928	625,414	36,311,109
7	RBO	Materials and Supplies	EXPENDITURES	227,211,892	127,602,643	587,453	1,042,096	14,620	228	153,505	8,912,399
8	RBO	Prepayments	EXPENDITURES	500,266	280,951	1,293	2,294	32	1	338	19,623
9	RBO	Working Funds	EXPENDITURES								
10	RBO	Total Working Capital		1,153,424,258	647,765,319	2,982,162	5,290,124	74,217	1,156	779,257	45,243,131
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,016,196,832	548,955,762	2,790,983	4,852,122	24,736	386	795,226	35,683,679
12	RBO	Plant Held for Future Use	TOTPLT	495,177	269,300	1,359	2,361	12	0	381	17,101
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	286,198,206	154,114,816	777,304	1,360,250	5,876	92	221,259	10,212,632
15	RBO	CEF-EC Adjustment	ECPRO_07	670,378,464	587,103,967	1,891,565	3,160,266	498,899	7,783	214,841	
16	RBO	CEF-EV Adjustment	TOTREV	43,223,143	24,509,919	114,321	202,509	3,065	48	29,793	1,459,758
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,169,916,080	1,962,719,084	8,557,694	14,867,631	606,805	9,464	2,040,757	92,616,302
18	RBO										
19	RBO										
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**									
21	RBO										
22	RBO	Customer Advances for Construction	REVREQ	(63,735,780)	(36,212,594)	(168,905)	(299,200)	(4,529)	(71)	(43,798)	(2,156,744)
23	RBO	Unbilled Revenue	TOTREV								
24	RBO	IAP Adjustment	E365PLT	(27,893,945)	(14,720,401)	(66,521)	(141,432)			(25,826)	(66,923)
25	RBO	Deferred Income Taxes and Credits									
26	RBO	ADIT Test/Post year	TOTPLT								
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(1,222,438)	(6,168)	(10,717)	(55)	(1)	(1,731)	(77,627)
28	RBO	Cost of Removal	TOTPLT	15,629,066	8,499,813	42,885	74,516	381	6	12,036	539,751
29	RBO	3% Investment Tax Credit	DISTPLT								
30	RBO	Computer Software	INTANGPLT								
31	RBO	Capitalized Interest	TOTPLTNET	312,066	168,044	848	1,483	6	0	241	11,136
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	3,434,885	17,324	30,317	131	2	4,931	227,617
33	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,820,476,207)	(990,059,647)	(4,995,196)	(8,679,617)	(44,385)	(692)	(1,401,978)	(62,870,243)
34	RBO	Total Deferred Income Taxes and Credits		(1,800,404,102)	(979,179,343)	(4,940,307)	(8,584,018)	(43,922)	(685)	(1,386,500)	(62,169,366)
35	RBO										
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,892,033,827)	(1,030,112,338)	(5,175,733)	(9,024,650)	(48,451)	(755)	(1,456,124)	(64,393,033)
37	RBO										
38	RBO										
39	RBO	**TOTAL RATE BASE**		9,635,540,505	5,433,120,523	26,081,061	45,565,460	729,937	11,384	7,045,925	326,456,069

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	374,599	13,440,522	173,908,790	123,099,949	27,171,235	23,988,085	211,030
7	RBO	Materials and Supplies	EXPENDITURES	91,944	3,298,916	42,685,134	30,214,332	6,669,058	5,887,768	51,796
8	RBO	Prepayments	EXPENDITURES	202	7,263	93,982	66,525	14,684	12,963	114
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		466,745	16,746,702	216,687,907	153,380,805	33,854,976	29,888,817	262,941
11	RBO	Net Plant Adds - Distribution	DISTPLT	73,426	10,979,335	199,577,268	148,536,148	32,984,250	30,853,993	89,518
12	RBO	Plant Held for Future Use	TOTPLT	36	5,352	97,066	71,569	15,823	14,774	42
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	20,488	3,177,651	55,806,514	42,299,140	9,360,949	8,820,336	20,898
15	RBO	CEF-EC Adjustment	ECPRO_07			77,501,143				
16	RBO	CEF-EV Adjustment	TOTREV	11,621	521,233	8,123,682	5,818,608	1,272,807	1,151,567	4,213
17	RBO	TOTAL ADDITIONS TO RATE BASE		572,316	31,430,272	557,793,581	350,106,270	77,488,806	70,729,486	377,612
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(17,170)	(766,255)	(11,942,471)	(8,553,824)	(1,871,130)	(1,692,896)	(6,193)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(2,154)	(85,062)	(5,892,049)	(4,804,994)	(1,234,773)	(853,810)	
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(161)	(24,295)	(440,614)	(324,875)	(71,826)	(67,064)	(192)
28	RBO	Cost of Removal	TOTPLT	1,121	168,928	3,063,660	2,258,911	499,415	466,306	1,338
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	22	3,465	60,850	46,122	10,207	9,618	23
32	RBO	NJ Corporate Business Tax	TOTPLTNET	457	70,823	1,243,806	942,756	208,635	196,586	466
33	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(130,611)	(19,676,779)	(356,855,595)	(263,118,368)	(58,171,934)	(54,315,351)	(155,811)
34	RBO	Total Deferred Income Taxes and Credits		(129,172)	(19,457,858)	(352,927,893)	(260,195,453)	(57,525,502)	(53,709,906)	(154,177)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(148,496)	(20,309,175)	(370,762,413)	(273,554,272)	(60,631,405)	(56,256,612)	(160,370)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		1,022,124	103,915,941	1,816,712,160	1,311,785,994	290,219,052	272,047,354	827,520

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	REV	**OPERATING REVENUES**									
2	REV										
3	REV	**SALES REVENUES**									
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
8	REV										
9	REV	**OTHER OPERATING REVENUES**									
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	0	0	0	0	0	6,432	0
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	12,164,111	56,737	100,504	1,521	24	14,786	724,468
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	12,164,111	56,737	100,504	1,521	24	21,218	724,468
15	REV										
16	REV	**OTHER REVENUE SOURCES**									
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0
20	REV										
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0
22	REV										
23	REV	**TOTAL OPERATING REVENUES**		1,887,985,784	1,070,592,616	4,993,518	8,845,571	133,897	2,086	1,301,354	63,762,201

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	0	112,523	1,753,730	1,256,113	274,772	248,599	909
11	REV	456-Other Electric Revenues	TOTREV	5,768	258,684	4,031,730	2,887,737	631,686	571,515	2,091
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		5,768	371,208	5,785,460	4,143,850	906,458	820,114	3,000
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		507,620	22,767,438	354,842,239	254,156,637	55,596,191	50,300,403	184,015

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	E	**OPERATION & MAINTENANCE EXPENSE**									
2	E	PRODUCTION EXPENSE									
3	E	E500-E557 Production Expenses									
4	E	Not Used	not_used	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0
7	E										
8	E	TRANSMISSION EXPENSES									
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0
11	E										
12	E	DISTRIBUTION EXPENSES									
13	E	Operation									
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	1,158,421	3,719	13,027	0	0	811	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	2,214,288	10,006	21,275	0	0	3,885	10,067
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	3,397,340	16,750	30,895	0	0	7,079	24,363
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	11,372	59	103	0	0	17	118,906
20	E	E586 Meter Expenses									
21	E	- Basic portion (minimum size)	MTROMMIN_07	5,865,310	2,939,512	10,212	17,062	2,798	44	1,160	0
22	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses									
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	16,430,937	72,401	152,332	4,517	70	26,504	324,609
27	E	E589 Rents	DISTPLT	1,330,133	718,546	3,653	6,351	32	1	1,041	46,708
28	E	Total Distribution Operation		53,572,940	24,631,187	109,021	228,046	6,606	103	39,613	519,124
29	E	Maintenance									
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	5,906,557	22,385	62,024	82	1	5,504	118,763
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	7,852,767	25,208	88,306	0	0	5,500	0
33	E	E593 Maint of Overhead Lines									
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	0	0	0	0	0	0	40,988
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	29,713,808	134,276	285,487	0	0	52,130	135,087
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	11,001,299	54,242	100,044	0	0	22,923	78,891
38	E	Not used		0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers	LNTRFRMR_04	4,205,529	3,002,390	22,770	19,075	0	0	4,016	13,030
40	E	E596 Maint of Street Lighting & Signal Systems									
41	E	- BPL luminaires	DIR_BPL_02	8,123,869	0	0	0	0	0	0	8,123,869
42	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0	0
43	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	0	0	0	0	0	0	0
44	E	E597 Maint of Meters									
45	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0
46	E	- Basic portion (minimum size)	MTROMMIN_07	858,670	430,339	1,495	2,498	410	6	170	0
47	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
48	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	578,834	2,603	5,572	5	0	902	85,071
49	E	Total Distribution Maintenance		124,436,319	58,485,994	262,978	563,006	497	8	91,145	8,595,700
50	E										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	0	0	606,045	498,172	128,325	131,059	0
17	E	E583 OH Line Expenses	E365PLT	324	12,795	886,300	722,782	185,738	128,433	0
18	E	E584 Underground Line Expenses	E367PLT	653	10,669	1,228,865	998,355	257,529	227,411	0
19	E	E585 Street Lighting and System Expenses	E373PLT	2	33,839	4,211	3,219	712	667	0
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	MTROMMIN_07	0	0	405,220	2,249,681	187,387	46,040	6,195
22	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses								
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	1,928	67,887	6,166,476	9,798,207	1,666,444	1,171,408	13,541
27	E	E589 Rents	DISTPLT	96	14,371	261,233	194,424	43,174	40,386	117
28	E	Total Distribution Operation		2,902	113,170	9,235,567	14,454,170	2,468,421	1,745,186	19,824
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	244	36,542	2,798,493	2,248,731	561,690	564,227	298
32	E	E592 Maint of Station Equipment	E362PLT	0	0	4,108,289	3,377,036	869,896	888,429	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	0	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	4,348	171,702	11,893,373	9,699,103	2,492,447	1,723,455	0
37	E	E594.0 Maint of Underground Lines	E367PLT	2,114	34,550	3,979,323	3,232,883	833,933	736,405	0
38	E	Not used		0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers	LNTRFRMR_04	594	5,676	588,828	549,150	0	0	0
40	E	E596 Maint of Street Lighting & Signal Systems								
41	E	- BPL luminaires	DIR_BPL_02	0	0	0	0	0	0	0
42	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0
43	E	- PSAL luminaires	DIR_PSAL_02	0	3,594,664	0	0	0	0	0
44	E	E597 Maint of Meters								
45	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
46	E	- Basic portion (minimum size)	MTROMMIN_07	0	0	59,323	329,349	27,433	6,740	907
47	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
48	E	E598 Other Dist Maint Exp	DISTEXPM	3,472	39,597	234,180	194,283	47,834	39,176	12
49	E	Total Distribution Maintenance		350,824	4,000,941	23,661,810	19,630,534	4,833,233	3,958,432	1,217
50	E									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
52	E										
53	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
54	E										
55	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	83,117,180	371,999	791,052	7,103	111	130,759	9,114,824
56	E										
57	E										
58	E	CUSTOMER ACCOUNTS EXPENSES									
59	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0
60	E	E902 Meter Reading									
61	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0	0
62	E	- Meter Reading	MRCOST_07	18,646,973	14,679,249	50,997	85,201	972	15	1,158	0
63	E	- Billing	BILLING_06	0	0	0	0	0	0	0	0
64	E	- Remaining	MRCOST_07	-567,391	-446,661	-1,552	-2,593	-30	0	-35	0
65	E	E903 Customer Records and Collection									
66	E	- SONP/RNP	CUSTAVG_06	550,664	469,157	1,630	2,723	155	2	185	1,158
67	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0	0
68	E	- Meter Reading	MRCOST_07	533,054	419,630	1,458	2,436	28	0	33	0
69	E	- Billing	BILLING_06	80,993	58,538	203	340	4	0	5	246
70	E	- Acct Maint related	ACCTMAINT_06	7,745,024	6,451,315	22,412	37,445	2,039	32	2,430	1,840
71	E	- Utility work related	UTILWORK_04	1,062,937	777,147	2,484	5,302	65	1	359	5,313
72	E	- Remaining	BILLING_06	66,341,808	47,948,497	166,577	278,303	3,175	50	3,784	201,196
73	E	Not used	not_used	0	0	0	0	0	0	0	0
74	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0
75	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0	0
76	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
77	E										
78	E										
79	E	CUSTOMER SERVICE & INFO EXPENSES									
80	E	E907 & 908 - Cust Svs & Info									
81	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0
82	E	- Acct Maint related	ACCTMAINT_06	2,356,739	1,963,075	6,820	11,394	620	10	739	560
83	E	- Utility work related	UTILWORK_04	847,228	619,436	1,980	4,226	51	0	286	4,234
84	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
85	E	- Billing	BILLING_06	41,297	29,847	104	173	2	0	2	125
86	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0
87	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0
88	E	E910 - Misc Cust Svs & Info									
89	E	- Utility work related	UTILWORK_04	1,163,089	850,371	2,718	5,801	71	1	392	5,813
90	E	- Acct Maint related	ACCTMAINT_06	689,620	574,428	1,996	3,334	182	3	216	164
91	E	- Not used	not_used	0	0	0	0	0	0	0	0
92	E	- Not used	not_used	0	0	0	0	0	0	0	0
93	E	- Not used	not_used	0	0	0	0	0	0	0	0
94	E	- Not used	not_used	0	0	0	0	0	0	0	0
95	E	- Remaining	BILLING_06	220,028	159,025	552	923	11	0	13	667
96	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
97	E										
98	E										
99	E										
100	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
52	E									
53	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
54	E									
55	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		353,726	4,114,111	32,897,377	34,084,705	7,301,654	5,703,617	21,041
56	E									
57	E									
58	E	CUSTOMER ACCOUNTS EXPENSES								
59	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
60	E	E902 Meter Reading								
61	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
62	E	- Meter Reading	MRCOST_07	0	0	3,597,205	209,825	17,477	4,294	578
63	E	- Billing	BILLING_06	0	0	0	0	0	0	0
64	E	- Remaining	MRCOST_07	0	0	-109,456	-6,385	-532	-131	-18
65	E	E903 Customer Records and Collection								
66	E	- SONP/RNP	CUSTAVG_06	21	5,530	67,629	2,235	186	46	6
67	E	- Meter O&M	METERPLT	0	0	0	0	0	0	0
68	E	- Meter Reading	MRCOST_07	0	0	102,832	5,998	500	123	17
69	E	- Billing	BILLING_06	4	1,173	14,345	5,545	462	113	15
70	E	- Acct Maint related	ACCTMAINT_06	33	8,785	967,013	227,454	18,946	4,655	626
71	E	- Utility work related	UTILWORK_04	99	14,413	238,105	17,580	1,588	445	38
72	E	- Remaining	BILLING_06	3,660	960,714	11,749,958	4,542,099	378,333	92,955	12,508
73	E	Not used	not_used	0	0	0	0	0	0	0
74	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
75	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
76	E	TOTAL CUSTOMER ACCTS EXPENSE		3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
77	E									
78	E									
79	E	CUSTOMER SERVICE & INFO EXPENSES								
80	E	E907 & 908 - Cust Svs & Info								
81	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
82	E	- Acct Maint related	ACCTMAINT_06	10	2,673	294,253	69,212	5,765	1,416	191
83	E	- Utility work related	UTILWORK_04	79	11,488	189,785	14,013	1,266	355	30
84	E	- Sales	SALES_06	0	0	0	0	0	0	0
85	E	- Billing	BILLING_06	2	598	7,314	2,827	236	58	8
86	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
87	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
88	E	E910 - Misc Cust Svs & Info								
89	E	- Utility work related	UTILWORK_04	108	15,771	260,539	19,237	1,737	487	41
90	E	- Acct Maint related	ACCTMAINT_06	3	782	86,103	20,253	1,687	414	56
91	E	- Not used	not_used	0	0	0	0	0	0	0
92	E	- Not used	not_used	0	0	0	0	0	0	0
93	E	- Not used	not_used	0	0	0	0	0	0	0
94	E	- Not used	not_used	0	0	0	0	0	0	0
95	E	- Remaining	BILLING_06	12	3,186	38,970	15,064	1,255	308	41
96	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		214	34,498	876,964	140,606	11,945	3,040	367
97	E									
98	E									
99	E									
100	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	E										
102	E	SALES EXPENSES									
103	E	E911-E916 Sales Expenses									
104	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
105	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0
106	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0
107	E	- Utility work related	UTILWORK_04	40,922	29,919	96	204	2	0	14	205
108	E	- Remaining	BILLING_06	0	0	0	0	0	0	0	0
109	E	- Clause	not_used	0	0	0	0	0	0	0	0
110	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	29,919	96	204	2	0	14	205
111	E										
112	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	157,700,154	630,475	1,226,265	14,450	224	140,340	9,336,344
113	E										
114	E	ADMINISTRATIVE & GENERAL EXPENSE									
115	E	E920 A&G Salaries	LABOR	5,694,688	3,554,504	13,737	24,932	522	8	2,409	218,581
116	E	E921 Office Supplies & Exp	LABOR	622,444	388,516	1,502	2,725	57	1	263	23,891
117	E	E923 Outside Services Employed	DISTPLT	68,020,983	36,745,352	186,820	324,786	1,656	26	53,230	2,388,552
118	E	E924 Property Insurance	TOTPLT	1,802,573	980,323	4,946	8,594	44	1	1,388	62,252
119	E	E925 Injuries & Damages	LABOR	14,161,029	8,839,016	34,161	61,999	1,299	20	5,991	543,547
120	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-48,665,178	-188,081	-341,347	-7,152	-111	-32,984	-2,992,619
121	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	8,546,586	39,863	70,615	1,069	17	10,337	509,016
122	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	0	0	0	0	0	0
123	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	1,940,410	6,741	11,263	642	10	766	4,789
124	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	1,584,191	8,054	14,002	71	1	2,295	102,977
125	E	E931 Rents	DISTPLT	4,471,819	2,415,704	12,282	21,352	109	2	3,499	157,028
126	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0
127	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0
128	E	Not Used	not_used	0	0	0	0	0	0	0	0
129	E	TOTAL A&G EXPENSE		33,695,393	16,329,425	120,025	198,920	-1,682	-26	47,194	1,018,014
130	E										
131	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	174,029,579	750,500	1,425,184	12,768	198	187,534	10,354,358

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	E									
102	E	SALES EXPENSES								
103	E	E911-E916 Sales Expenses								
104	E	- Sales	SALES_06	0	0	0	0	0	0	0
105	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
106	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
107	E	- Utility work related	UTILWORK_04	4	555	9,167	677	61	17	1
108	E	- Remaining	BILLING_06	0	0	0	0	0	0	0
109	E	- Clause	not_used	0	0	0	0	0	0	0
110	E	SALES EXPENSES TOTAL (ACCT 916)		4	555	9,167	677	61	17	1
111	E									
112	E	TOTAL OPER & MAINT EXCL A&G		357,761	5,139,779	50,411,138	39,230,340	7,730,620	5,809,175	35,179
113	E									
114	E	ADMINISTRATIVE & GENERAL EXPENSE								
115	E	E920 A&G Salaries	LABOR	336	91,620	955,213	633,704	113,582	84,779	760
116	E	E921 Office Supplies & Exp	LABOR	37	10,014	104,407	69,265	12,415	9,267	83
117	E	E923 Outside Services Employed	DISTPLT	4,915	734,922	13,359,067	9,942,537	2,207,861	2,065,268	5,992
118	E	E924 Property Insurance	TOTPLT	129	19,483	353,346	260,531	57,600	53,781	154
119	E	E925 Injuries & Damages	LABOR	835	227,833	2,375,336	1,575,838	282,445	210,821	1,890
120	E	E926 Employee Pension & Benefits	LABOR	-4,597	-1,254,386	-13,077,942	-8,676,126	-1,555,064	-1,160,720	-10,406
121	E	E928 Regulatory Comm Exp	REVREQ	4,052	180,845	2,818,560	2,018,800	441,608	399,543	1,462
122	E	E929 Duplicate Charges - credit	REVLPLS	0	0	0	-3,363,888	0	0	0
123	E	E930.1 General Advertising Expenses	CUSTAVG_04	87	22,870	279,709	9,245	770	189	25
124	E	E930.2 Misc General Expenses	DISTPLT	212	31,684	575,945	428,650	95,187	89,039	258
125	E	E931 Rents	DISTPLT	323	48,315	878,249	653,640	145,149	135,774	394
126	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
127	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
128	E	Not Used	not_used	0	0	0	0	0	0	0
129	E	TOTAL A&G EXPENSE		6,330	113,201	8,621,889	3,552,196	1,801,552	1,887,742	613
130	E									
131	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		364,091	5,252,980	59,033,027	42,782,536	9,532,172	7,696,917	35,792

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**									
2	DE										
3	DE	E403 DEPRECIATION EXPENSE									
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	139,248,473	707,963	1,230,792	6,275	98	201,718	9,051,545
7	DE	General Plant	GENPLT	19,786,964	10,525,555	54,517	94,895	41	1	15,831	719,212
8	DE	Common Plant	COMPLT	9,215,747	6,359,537	24,284	41,271	503	8	2,617	104,443
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
11	DE										
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT									
13	DE	not used	not_used	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	3,230,427	16,732	29,125	13	0	4,859	220,735
15	DE	Meter Reading	MRCOST_07	492,670	387,839	1,347	2,251	26	0	31	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	11,085,171	38,418	64,681	1,092	17	1,423	32,907
17	DE	not used	not_used	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
20	DE										
21	DE	E407 AMORT OF PROPERTY LOSSES									
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0
26	DE										
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	14,703,437	56,497	96,056	1,130	17	6,312	253,642
28	DE										
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	170,837,002	843,261	1,463,015	7,948	124	226,477	10,128,842

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	18,625	2,785,025	50,624,898	37,677,775	8,366,806	7,826,444	22,707
7	DE	General Plant	GENPLT	1,480	221,291	3,897,833	2,979,325	659,334	617,626	23
8	DE	Common Plant	COMPLT	457	96,967	1,670,597	719,080	111,058	83,965	961
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	454	67,917	1,196,295	914,393	202,358	189,557	7
15	DE	Meter Reading	MRCOST_07	0	0	95,041	5,544	462	113	15
16	DE	Customer Service related	CUSTSVSX	600	152,422	2,602,729	764,995	63,773	15,693	2,102
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		1,054	220,339	3,894,065	1,684,932	266,593	205,364	2,124
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		21,616	3,323,622	60,087,393	43,061,113	9,403,791	8,733,399	25,816

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	EO	**OTHER OPERATING EXPENSES**									
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**									
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-149,822	-756	-1,313	-7	0	-212	-9,514
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-7,038,074	-27,201	-49,366	-1,034	-16	-4,770	-432,800
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-7,187,896	-27,957	-50,680	-1,041	-16	-4,982	-442,314
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**									
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	21,861,618	19,145,965	61,686	103,059	16,270	254	7,006	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	4,303,381	2,317,327	11,688	20,453	88	1	3,327	153,561
14	EO	BGS Administrative Expense Adjustment	A_GEXP	-220,495	-128,343	-608	-1,067	-11	0	-158	-7,920
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-1,199,974	-748,998	-2,895	-5,254	-110	-2	-508	-46,059
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,361,661	4,594,994	17,759	32,230	675	10	3,114	282,565
22	EO	Payroll Taxes (Rate Year)	LABOR	506,132	315,917	1,221	2,216	46	1	214	19,427
23	EO	Interest Syncronization	TOTPLTNET	-1,029,929	-554,606	-2,797	-4,895	-21	0	-796	-36,752
24	EO	- add'l tax effects on rev req	TOTPLTNET	-402,717	-216,859	-1,094	-1,914	-8	0	-311	-14,370
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	20,935,341	13,067,398	50,503	91,657	1,921	30	8,857	803,567
26	EO	COLI Interest Expense Recovery	LABOR	2,119,856	1,323,169	5,114	9,281	194	3	897	81,367
27	EO	- add'l tax effects on rev req	LABOR	828,893	517,378	2,000	3,629	76	1	351	31,816
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-41,607	-22,628	-114	-198	-1	0	-32	-1,437
32	EO	- add'l tax effects on rev req	TOTPLT	-16,269	-8,848	-45	-78	0	0	-13	-562
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	616,778	335,432	1,692	2,941	15	0	475	21,300
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-9,395,531	-47,404	-82,368	-421	-7	-13,305	-596,630
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	482,666	262,496	1,324	2,301	12	0	372	16,669
38	EO	Rate Case Expenses	TOTPLT	188,766	102,659	518	900	5	0	145	6,519
39	EO	Depreciation Rate Change	DEPREXP	44,543,977	24,252,066	122,207	212,328	1,059	17	34,198	1,533,905
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT								
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		83,562,007	55,148,025	220,712	385,145	26,925	419	43,826	2,246,292
47	EO										
48	EO	**TOTAL OTHER OPERATING EXPENSES**		72,010,790	47,960,130	192,756	334,465	25,883	403	38,843	1,803,978
49	EO	TOTAL OPERATING REVENUES		1,887,985,784	1,070,592,616	4,993,518	8,845,571	133,897	2,086	1,301,354	63,762,201
50	EO	LESS:									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-20	-2,978	-54,001	-39,817	-8,803	-8,219	-24
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-665	-181,412	-1,891,363	-1,254,762	-224,897	-167,866	-1,505
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-685	-184,390	-1,945,365	-1,294,579	-233,700	-176,085	-1,528
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	0	0	2,527,379	0	0	0	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	308	47,780	839,127	636,025	140,755	132,626	314
14	EO	BGS Administrative Expense Adjustment	A_GEXP	-22	-2,701	-42,850	-24,147	-6,628	-6,020	-22
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-71	-19,306	-201,281	-133,533	-23,934	-17,864	-160
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	434	118,440	1,234,827	819,205	146,830	109,596	983
22	EO	Payroll Taxes (Rate Year)	LABOR	30	8,143	84,897	56,322	10,095	7,535	68
23	EO	Interest Syncronization	TOTPLTNET	-74	-11,435	-200,828	-152,220	-33,687	-31,741	-75
24	EO	- add'l tax effects on rev req	TOTPLTNET	-29	-4,471	-78,527	-59,520	-13,172	-12,411	-29
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	1,234	336,823	3,511,642	2,329,682	417,560	311,672	2,794
26	EO	COLI Interest Expense Recovery	LABOR	125	34,106	355,579	235,897	42,281	31,559	283
27	EO	- add'l tax effects on rev req	LABOR	49	13,336	139,037	92,239	16,532	12,340	111
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-3	-450	-8,156	-6,014	-1,330	-1,241	-4
32	EO	- add'l tax effects on rev req	TOTPLT	-1	-176	-3,189	-2,351	-520	-485	-1
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	44	6,666	120,903	89,145	19,709	18,402	53
36	EO	Test Year Amortization Adjustments	TOTPLT	-1,239	-186,730	-3,386,511	-2,496,957	-552,044	-515,445	-1,479
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	35	5,217	94,614	69,761	15,423	14,401	41
38	EO	Rate Case Expenses	TOTPLT	14	2,040	37,002	27,283	6,032	5,632	16
39	EO	Depreciation Rate Change	DEPREXP	3,194	482,030	8,728,452	6,426,920	1,419,272	1,324,651	3,680
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT							
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		4,027	829,030	13,749,170	7,905,781	1,602,824	1,382,943	16,888
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		3,342	644,640	11,803,805	6,611,203	1,369,124	1,206,858	15,359
49	EO	TOTAL OPERATING REVENUES		507,620	22,767,438	354,842,239	254,156,637	55,596,191	50,300,403	184,015
50	EO	LESS:								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	EO	OPERATION & MAINTAINENCE EXPENSE		311,457,637	174,029,579	750,500	1,425,184	12,768	198	187,534	10,354,358
52	EO	DEPRECIATION & AMORTIZATION EXPENSE		308,163,419	170,837,002	843,261	1,463,015	7,948	124	226,477	10,128,842
53	EO	OTHER OPERATING EXPENSES		72,010,790	47,960,130	192,756	334,465	25,883	403	38,843	1,803,978
54	EO	NET OPERATING INCOME BEFORE TAXES		1,196,353,939	677,765,904	3,207,001	5,622,906	87,297	1,361	848,499	41,475,022
55	EO	LESS:									
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(74,088,268)	(373,677)	(653,919)	(2,825)	(44)	(106,367)	(4,909,562)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,333,939,214	751,854,173	3,580,678	6,276,824	90,122	1,405	954,866	46,384,585
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	EO	OPERATION & MAINTAINENCE EXPENSE		364,091	5,252,980	59,033,027	42,782,536	9,532,172	7,696,917	35,792
52	EO	DEPRECIATION & AMORTIZATION EXPENSE		21,616	3,323,622	60,087,393	43,061,113	9,403,791	8,733,399	25,816
53	EO	OTHER OPERATING EXPENSES		3,342	644,640	11,803,805	6,611,203	1,369,124	1,206,858	15,359
54	EO	NET OPERATING INCOME BEFORE TAXES		118,571	13,546,196	223,918,014	161,701,786	35,291,104	32,663,230	107,047
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(9,849)	(1,527,605)	(26,828,102)	(20,334,644)	(4,500,129)	(4,240,237)	(10,047)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		128,420	15,073,802	250,746,116	182,036,430	39,791,233	36,903,467	117,094
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	0	0	0	0	0	0	10,316

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**									
2	TI										
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**									
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-108,083	-58,781	-297	-515	-3	0	-83	-3,733
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	16,349	8,891	45	78	0	0	13	565
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	6,402	32	56	0	0	9	407
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-20,866,765	-11,348,318	-57,256	-99,488	-509	-8	-16,070	-720,635
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-1,855,840	-1,009,292	-5,092	-8,848	-45	-1	-1,429	-64,092
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-1,117,127	-697,287	-2,695	-4,891	-102	-2	-473	-42,879
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-58,279	-36,377	-141	-255	-5	0	-25	-2,237
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-11,513,122	-6,268,345	-31,586	-54,880	-274	-4	-8,839	-396,463
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	4,645,423	2,501,513	12,617	22,079	95	1	3,591	165,766
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	6,684,538	3,599,556	18,155	31,770	137	2	5,168	238,530
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-5,352	-3,340	-13	-23	0	0	-2	-205
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-7,086,760	-4,423,406	-17,096	-31,027	-650	-10	-2,998	-272,013
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	82	44	0	0	0	0	0	3
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	38,419	23,980	93	168	4	0	16	1,475
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	1,298,774	706,334	3,564	6,192	32	0	1,000	44,853
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-33,454,683	-18,214,476	-91,784	-159,469	-795	-12	-25,684	-1,152,037
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	162,269	101,285	391	710	15	0	69	6,228
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-5,622	-3,058	-15	-27	0	0	-4	-194
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-236,259	-128,489	-648	-1,126	-6	0	-182	-8,159
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	319,172	173,581	876	1,522	8	0	246	11,023
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	42,165	22,931	116	201	1	0	32	1,456
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	154,681	96,549	373	677	14	0	65	5,937
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	17,908,279	9,750,202	49,132	85,364	426	7	13,749	616,685
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-250,663	-1,265	-2,197	-11	0	-355	-15,917
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	125,367	68,181	344	598	3	0	97	4,330
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-328,125	-176,692	-891	-1,560	-7	0	-254	-11,709
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-42,165	-22,931	-116	-201	-1	0	-32	-1,456

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**								
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-8	-1,168	-21,187	-15,622	-3,454	-3,225	-9
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	1	177	3,205	2,363	522	488	1
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	1	127	2,307	1,701	376	351	1
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-1,497	-225,540	-4,090,370	-3,015,930	-666,782	-622,576	-1,786
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-133	-20,059	-363,788	-268,230	-59,302	-55,370	-159
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-66	-17,973	-187,384	-124,314	-22,281	-16,631	-149
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-3	-938	-9,776	-6,485	-1,162	-868	-8
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-826	-124,588	-2,256,012	-1,661,143	-366,834	-342,378	-951
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	333	51,578	905,823	686,578	151,942	143,167	339
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	479	74,218	1,303,435	987,952	218,637	206,011	488
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	0	-86	-898	-596	-107	-80	-1
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-418	-114,017	-1,188,715	-788,614	-141,347	-105,503	-946
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	0	1	16	12	3	2	0
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	2	618	6,444	4,275	766	572	5
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	93	14,038	254,590	187,715	41,501	38,750	111
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-2,399	-362,028	-6,555,490	-4,826,928	-1,065,942	-994,877	-2,764
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	10	2,611	27,219	18,057	3,236	2,416	22
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	0	-61	-1,102	-813	-180	-168	0
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-17	-2,554	-46,312	-34,147	-7,549	-7,049	-20
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	23	3,450	62,565	46,131	10,199	9,523	27
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	3	456	8,265	6,094	1,347	1,258	4
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	9	2,489	25,946	17,213	3,085	2,303	21
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	1,284	193,793	3,509,151	2,583,853	570,598	532,557	1,479
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-33	-4,982	-90,348	-66,616	-14,728	-13,752	-39
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	9	1,355	24,575	18,120	4,006	3,740	11
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-23	-3,643	-63,982	-48,496	-10,732	-10,112	-24
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-3	-456	-8,265	-6,094	-1,347	-1,258	-4

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-417,376	-260,518	-1,007	-1,827	-38	-1	-177	-16,020
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-555,910	-2,804	-4,907	-21	0	-798	-36,838
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	1,841,683	1,149,540	4,443	8,063	169	3	779	70,690
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Book Depreciation	DEPREXP	0	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
63	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-1,076,666	-585,541	-2,954	-5,133	-26	0	-829	-37,183
64	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	3,363,340	1,829,141	9,229	16,036	82	1	2,590	116,153
65	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
69	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	11,058	6,902	27	48	1	0	5	424
70	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
71	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-344,695	-215,151	-832	-1,509	-32	0	-146	-13,231
72	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	87,346	47,503	240	416	2	0	67	3,016
73	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stock	LABOR	0	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
78	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	905,779	487,753	2,460	4,305	19	0	700	32,322
79	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
80	TI	[TI][Fed Tax Adj.] Pension	LABOR	-3,671,962	-2,291,961	-8,858	-16,076	-337	-5	-1,553	-140,942
81	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-105,080,197	-65,588,842	-253,488	-460,053	-9,640	-150	-44,454	-4,033,324
82	TI	[TI][Fed Tax Adj.] Deferred Return on CIP II	TOTPLT	66,348	36,083	182	316	2	0	51	2,291
83	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP II	TOTPLT	52,458	28,529	144	250	1	0	40	1,812
84	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
85	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	91,151	49,084	248	433	2	0	70	3,253
86	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0
87	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	1,120,547	603,403	3,043	5,326	23	0	866	39,985
88	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-1,045,327	-562,898	-2,839	-4,968	-21	0	-808	-37,301
89	TI										
90	TI										
91	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0	0
94	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-82,615	-44,488	-224	-393	-2	0	-64	-2,948
95	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0
96	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	401,853	216,394	1,091	1,910	8	0	311	14,340
97	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	107,143	58,270	294	511	3	0	83	3,700
98	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0
99	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	62,834	33,836	171	299	1	0	49	2,242
100	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	1,046,714	563,645	2,843	4,975	21	0	809	37,351

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-25	-6,715	-70,010	-46,446	-8,325	-6,214	-56
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-74	-11,462	-201,301	-152,578	-33,766	-31,816	-75
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	109	29,630	308,919	204,942	36,733	27,418	246
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Book Depreciation	DEPREXP	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
63	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-77	-11,637	-211,052	-155,613	-34,404	-32,123	-92
64	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	241	36,353	659,293	486,113	107,473	100,348	288
65	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
69	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	1	178	1,855	1,230	221	165	1
70	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
71	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-20	-5,546	-57,818	-38,358	-6,875	-5,132	-46
72	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	6	944	17,122	12,624	2,791	2,606	7
73	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipmer	TOTPLT	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stock	LABOR	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
78	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	65	10,057	176,620	133,871	29,626	27,915	66
79	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
80	TI	[TI][Fed Tax Adj.] Pension	LABOR	-216	-59,077	-615,926	-408,616	-73,238	-54,666	-490
81	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-6,195	-1,690,608	-17,625,890	-11,693,312	-2,095,849	-1,564,368	-14,024
82	TI	[TI][Fed Tax Adj.] Deferred Return on CIP II	TOTPLT	5	717	13,006	9,590	2,120	1,980	6
83	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP II	TOTPLT	4	567	10,283	7,582	1,676	1,565	4
84	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
85	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	7	1,012	17,774	13,472	2,981	2,809	7
86	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
87	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	80	12,441	218,498	165,613	36,651	34,534	82
88	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-75	-11,606	-203,831	-154,496	-34,190	-32,216	-76
89	TI									
90	TI									
91	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0
94	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-6	-917	-16,109	-12,210	-2,702	-2,546	-6
95	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
96	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	29	4,462	78,358	59,393	13,144	12,385	29
97	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	8	1,158	21,003	15,486	3,424	3,197	9
98	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0
99	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	4	698	12,252	9,287	2,055	1,936	5
100	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	75	11,622	204,101	154,701	34,236	32,259	76

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0
102	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT								
103	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-90,577,234	-371,749	-667,070	-11,457	-178	-74,784	-5,584,680
104	TI										
105	TI	**[TI] TAX ADJUSTMENTS - STATE**									
106	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0	0
107	TI	[TI] Federal Depreciation Reversal	DEPREXP	72,042,765	39,223,841	197,651	343,407	1,713	27	55,310	2,480,845
108	TI	[TI] State Tax Depreciation	DEPREXP	36,681,624	19,971,391	100,637	174,851	872	14	28,162	1,263,159
109	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0	0
110	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	59,195,232	298,287	518,258	2,585	40	83,472	3,744,004
111	TI										
112	TI	**[TI] TAXABLE NET INCOME - STATE**		1,293,338,867	720,472,171	3,507,216	6,128,012	81,250	1,267	963,554	44,543,909
113	TI	[TI] State Tax Liability		116,400,498	64,842,495	315,649	551,521	7,312	114	86,720	4,008,952
114	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0
115	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		116,400,498	64,842,495	315,649	551,521	7,312	114	86,720	4,008,952
116	TI										
117	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		1,068,213,981	596,434,443	2,893,279	5,058,233	71,353	1,113	793,363	36,790,953
118	TI	[TI] Federal Tax Liability		224,324,936	125,251,233	607,589	1,062,229	14,984	234	166,606	7,726,100
119	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0	0
120	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0	0
121	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		224,324,936	125,251,233	607,589	1,062,229	14,984	234	166,606	7,726,100
122	TI										
123	TI	**[TI] TOTAL INCOME TAX EXPENSE**		340,725,434	190,093,728	923,238	1,613,750	22,297	348	253,326	11,735,052
124	TI										
125	TI										
126	TI										
127	TI										
128	TI	**[TI] TAX RATES**									
129	TI	[TI] FEDERAL TAX RATE - CURRENT		21.000%							
130	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE		9.000%							
131	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0							
132	TI	[TI] EFFECTIVE TAX RATE		28.110%							
133	TI	[TI] COMPOSITE RATE		28.110%							
134	TI	[TI] 1 - EFFECTIVE TAX RATE		71.89000%							
135	TI										
136	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**									
137	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-16,349	-8,891	-45	-78	0	0	-13	-565
138	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0	0
140	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	53,745	29,229	147	256	1	0	41	1,856
141	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-603,403	-3,043	-5,326	-23	0	-866	-39,985
142	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0	0
143	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	20,866,765	11,348,318	57,256	99,488	509	8	16,070	720,635
144	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	1,855,840	1,009,292	5,092	8,848	45	1	1,429	64,092
145	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0	0
150	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	2,912,070	1,585,483	7,989	13,881	69	1	2,236	100,279

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0
102	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT							
103	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-9,236	-2,220,912	-26,012,941	-17,691,687	-3,371,745	-2,712,673	-18,390
104	TI									
105	TI	**[TI] TAX ADJUSTMENTS - STATE**								
106	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0
107	TI	[TI] Federal Depreciation Reversal	DEPREXP	5,166	779,606	14,116,876	10,394,515	2,295,445	2,142,411	5,952
108	TI	[TI] State Tax Depreciation	DEPREXP	2,630	396,948	7,187,813	5,292,519	1,168,759	1,090,840	3,030
109	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0
110	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		7,796	1,176,554	21,304,689	15,687,035	3,464,204	3,233,251	8,982
111	TI									
112	TI	**[TI] TAXABLE NET INCOME - STATE**		126,980	14,029,443	246,037,864	180,031,778	39,883,692	37,424,046	107,686
113	TI	[TI] State Tax Liability		11,428	1,262,650	22,143,408	16,202,860	3,589,532	3,368,164	9,692
114	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
115	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		11,428	1,262,650	22,143,408	16,202,860	3,589,532	3,368,164	9,692
116	TI									
117	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		107,756	11,590,240	202,589,767	148,141,884	32,829,955	30,822,630	89,013
118	TI	[TI] Federal Tax Liability		22,629	2,433,950	42,543,851	31,109,796	6,894,291	6,472,752	18,693
119	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0
120	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0
121	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		22,629	2,433,950	42,543,851	31,109,796	6,894,291	6,472,752	18,693
122	TI									
123	TI	**[TI] TOTAL INCOME TAX EXPENSE**		34,057	3,696,600	64,687,259	47,312,656	10,483,823	9,840,916	28,384
124	TI									
125	TI									
126	TI									
127	TI									
128	TI	**[TI] TAX RATES**								
129	TI	[TI] FEDERAL TAX RATE - CURRENT								
130	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE								
131	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE								
132	TI	[TI] EFFECTIVE TAX RATE								
133	TI	[TI] COMPOSITE RATE								
134	TI	[TI] 1 - EFFECTIVE TAX RATE								
135	TI									
136	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
137	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-1	-177	-3,205	-2,363	-522	-488	-1
138	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0
140	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	4	581	10,535	7,768	1,717	1,604	5
141	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-80	-12,441	-218,498	-165,613	-36,651	-34,534	-82
142	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0
143	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	1,497	225,540	4,090,370	3,015,930	666,782	622,576	1,786
144	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	133	20,059	363,788	268,230	59,302	55,370	159
145	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0
150	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	209	31,513	570,624	420,161	92,785	86,599	241

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-4,645,423	-2,501,513	-12,617	-22,079	-95	-1	-3,591	-165,766
152	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	5,352	3,340	13	23	0	0	2	205
153	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	7,086,760	4,423,406	17,096	31,027	650	10	2,998	272,013
154	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0	0
156	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-328,505	-178,656	-901	-1,566	-8	0	-253	-11,345
157	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0	0
159	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	42,165	22,931	116	201	1	0	32	1,456
160	TI	[TI] 410 + 411 - Plant Related	DEPREXP	37,305,084	20,310,835	102,347	177,823	887	14	28,640	1,284,628
161	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0	0
162	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-15,263	-8,301	-42	-73	0	0	-12	-527
163	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	236,259	128,489	648	1,126	6	0	182	8,159
164	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-319,172	-173,581	-876	-1,522	-8	0	-246	-11,023
165	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-1,046,714	-569,252	-2,872	-4,990	-26	0	-806	-36,148
166	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-42,165	-22,931	-116	-201	-1	0	-32	-1,456
167	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-154,681	-96,549	-373	-677	-14	0	-65	-5,937
168	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-17,908,279	-9,750,202	-49,132	-85,364	-426	-7	-13,749	-616,685
169	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-125,367	-68,181	-344	-598	-3	0	-97	-4,330
170	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T**									
171	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0
172	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0
173	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0
175	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
177	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	1,076,666	585,541	2,954	5,133	26	0	829	37,183
178	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-3,363,340	-1,829,141	-9,229	-16,036	-82	-1	-2,590	-116,153
179	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
182	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
183	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-11,058	-6,902	-27	-48	-1	0	-5	-424
184	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
185	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	344,695	215,151	832	1,509	32	0	146	13,231
186	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-87,346	-47,503	-240	-416	-2	0	-67	-3,016
187	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0
188	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
191	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-	LABOR	0	0	0	0	0	0	0	0
192	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
193	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-905,779	-487,753	-2,460	-4,305	-19	0	-700	-32,322
194	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
195	TI	[TI] 410 + 411 - Pension	LABOR	3,671,962	2,291,961	8,858	16,076	337	5	1,553	140,942
196	TI	[TI] 410 + 411 - OPEB	LABOR	105,080,197	65,588,842	253,488	460,053	9,640	150	44,454	4,033,324
197	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0
198	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0
199	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0	0
200	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-333	-51,578	-905,823	-686,578	-151,942	-143,167	-339
152	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	0	86	898	596	107	80	1
153	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	418	114,017	1,188,715	788,614	141,347	105,503	946
154	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0
156	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-24	-3,551	-64,395	-47,480	-10,497	-9,801	-28
157	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0
159	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	3	456	8,265	6,094	1,347	1,258	4
160	TI	[TI] 410 + 411 - Plant Related	DEPREXP	2,675	403,694	7,309,981	5,382,473	1,188,624	1,109,380	3,082
161	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0
162	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-1	-165	-2,992	-2,206	-488	-455	-1
163	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	17	2,554	46,312	34,147	7,549	7,049	20
164	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-23	-3,450	-62,565	-46,131	-10,199	-9,523	-27
165	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-75	-11,314	-205,180	-151,284	-33,447	-31,230	-90
166	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-3	-456	-8,265	-6,094	-1,347	-1,258	-4
167	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-9	-2,489	-25,946	-17,213	-3,085	-2,303	-21
168	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-1,284	-193,793	-3,509,151	-2,583,853	-570,598	-532,557	-1,479
169	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-9	-1,355	-24,575	-18,120	-4,006	-3,740	-11
170	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T**								
171	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
172	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
173	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0
175	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
177	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	77	11,637	211,052	155,613	34,404	32,123	92
178	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-241	-36,353	-659,293	-486,113	-107,473	-100,348	-288
179	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
182	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
183	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-1	-178	-1,855	-1,230	-221	-165	-1
184	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
185	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	20	5,546	57,818	38,358	6,875	5,132	46
186	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-6	-944	-17,122	-12,624	-2,791	-2,606	-7
187	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
188	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
191	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-	LABOR	0	0	0	0	0	0	0
192	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
193	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-65	-10,057	-176,620	-133,871	-29,626	-27,915	-66
194	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
195	TI	[TI] 410 + 411 - Pension	LABOR	216	59,077	615,926	408,616	73,238	54,666	490
196	TI	[TI] 410 + 411 - OPEB	LABOR	6,195	1,690,608	17,625,890	11,693,312	2,095,849	1,564,368	14,024
197	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
198	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
199	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0
200	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
201	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	108,083	58,781	297	515	3	0	83	3,733
202	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	1,045,327	652,471	2,522	4,577	96	1	442	40,123
203	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0	0
205	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0
206	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-66,348	-36,083	-182	-316	-2	0	-51	-2,291
207	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-52,458	-28,529	-144	-250	-1	0	-40	-1,812
208	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-6,684,538	-4,982,339	-17,294	-28,975	-454	-7	-561	-14,854
209	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0
211	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-91,151	-49,084	-248	-433	-2	0	-70	-3,253
212	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
215	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0	0
216	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	328,125	176,692	891	1,560	7	0	254	11,709
217	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
218	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-401,853	-216,394	-1,091	-1,910	-8	0	-311	-14,340
219	TI										
220	TI										
221	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**									
222	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**									
223	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-107,143	-57,696	-291	-509	-2	0	-83	-3,823
224	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET								
225	TI	**[TI] TOTAL DEFERRED INCOME TAX**		144,525,616	86,707,881	358,981	646,425	11,131	173	75,184	5,647,513
226	TI										
227	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0
229	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0
230	TI										
231	TI	**[TI] OPERATING INCOME ADJUSTED**		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
201	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	8	1,168	21,187	15,622	3,454	3,225	9
202	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	62	16,818	175,341	116,324	20,849	15,562	140
203	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0
205	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
206	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-5	-717	-13,006	-9,590	-2,120	-1,980	-6
207	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-4	-567	-10,283	-7,582	-1,676	-1,565	-4
208	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-270	-70,151	-1,177,490	-354,384	-29,527	-7,259	-975
209	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
211	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-7	-1,012	-17,774	-13,472	-2,981	-2,809	-7
212	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0
215	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0
216	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	23	3,643	63,982	48,496	10,732	10,112	24
217	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
218	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-29	-4,462	-78,358	-59,393	-13,144	-12,385	-29
219	TI									
220	TI									
221	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**								
222	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**								
223	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-8	-1,190	-20,892	-15,835	-3,504	-3,302	-8
224	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET							
225	TI	**[TI] TOTAL DEFERRED INCOME TAX**		9,081	2,180,600	25,157,397	17,579,324	3,389,115	2,745,219	17,592
226	TI									
227	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
229	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
230	TI									
231	TI	**[TI] OPERATING INCOME ADJUSTED**		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**									
2	LR										
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
4	LR										
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
6	LR										
7	LR	**DISTRIBUTION LABOR EXPENSE**									
8	LR	Operation									
9	LR	582-Station Equipment	E367PLT	280,636	153,779	758	1,398	0	0	320	1,103
10	LR	583-Overhead Lines	E367PLT	941,919	516,139	2,545	4,694	0	0	1,075	3,701
11	LR	584-Underground Lines	E367PLT	4,591,058	2,515,744	12,404	22,878	0	0	5,242	18,041
12	LR	586-Metering	MTROMMIN_07	4,311,826	2,160,954	7,507	12,543	2,057	32	853	
13	LR	587-Customer Installations	CUSTAVG_04	17,308,754	14,746,796	51,232	85,593	4,883	76	5,819	36,399
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	7,401,173	32,612	68,617	2,035	32	11,939	146,217
15	LR	Total Operation		43,603,802	27,494,585	107,058	195,722	8,974	140	25,248	205,461
16	LR	Maintenance									
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	1,277,994	5,431	12,665	32	0	1,426	46,086
19	LR	592-Station Equipment	E362PLT	8,699,368	3,968,190	12,738	44,623			2,779	
20	LR	593-Overhead Lines	E365PLT	11,294,340	5,960,333	26,935	57,266			10,457	27,097
21	LR	594-Underground Lines	E367PLT	11,333,758	6,210,515	30,621	56,477	0	0	12,941	44,536
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	1,754,504	13,306	11,147			2,347	7,614
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	515,180	2,668	4,645	2	0	775	5,386,887
24	LR	597-Meters	MTROMMIN_07	700,642	351,140	1,220	2,038	334	5	139	
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	248,776	1,119	2,395	2	0	388	36,563
26	LR	Total Maintenance		45,417,214	20,286,632	94,038	191,256	370	6	31,250	5,548,783
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	47,781,217	201,096	386,979	9,345	146	56,498	5,754,244
28	LR										
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	43,749,989	151,857	254,426	3,985	62	4,924	130,430
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	4,371,290	14,761	26,931	976	14	1,718	12,046
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP								
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	A_GEXP	5,748,870	3,346,216	15,863	27,815	282	4	4,128	206,486
33	LR	**Employee Pension/Benefits Acct E926**	LABOR								
34	LR										
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	99,248,713	383,577	696,150	14,587	226	67,268	6,103,206

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	30	483	55,624	45,190	11,657	10,294	0
10	LR	583-Overhead Lines	E367PLT	99	1,621	186,695	151,675	39,125	34,549	0
11	LR	584-Underground Lines	E367PLT	483	7,901	909,980	739,286	190,701	168,399	0
12	LR	586-Metering	MTROMMIN_07			297,894	1,653,831	137,755	33,846	4,554
13	LR	587-Customer Installations	CUSTAVG_04	662	173,807	2,125,740	70,264	5,853	1,438	193
14	LR	588-Miscellaneous	DISTEXPO	868	30,579	2,777,636	4,413,517	750,635	527,651	6,099
15	LR	Total Operation		2,142	214,391	6,353,567	7,073,763	1,135,727	776,176	10,847
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	95	14,180	555,442	436,535	105,632	104,224	116
19	LR	592-Station Equipment	E362PLT			2,076,017	1,706,497	439,579	448,944	
20	LR	593-Overhead Lines	E365PLT	872	34,442	2,385,708	1,945,556	499,963	345,710	
21	LR	594-Underground Lines	E367PLT	1,193	19,504	2,246,430	1,825,045	470,777	415,719	0
22	LR	595-Line Transformers	LNTRFRMR_04	347	3,317	344,093	320,906			
23	LR	596-Street Lighting and Signal Systems	E373PLT	72	1,533,026	190,782	145,825	32,272	30,230	1
24	LR	597-Meters	MTROMMIN_07			48,406	268,736	22,384	5,500	740
25	LR	598-Other Distribution Maintenance	DISTEXPM	1,492	17,018	100,648	83,500	20,559	16,838	5
26	LR	Total Maintenance		4,072	1,621,488	7,947,525	6,732,602	1,591,166	1,367,165	862
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		6,214	1,835,878	14,301,092	13,806,364	2,726,892	2,143,341	11,709
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	2,374	615,994	10,339,553	3,111,855	259,278	63,738	8,563
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	223	35,938	913,560	146,473	12,444	3,166	382
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP							
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	A_GEXP	563	70,410	1,117,205	629,569	172,814	156,949	567
33	LR	**Employee Pension/Benefits Acct E926**	LABOR							
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		9,374	2,558,220	26,671,410	17,694,261	3,171,428	2,367,194	21,221

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**									
2	CA										
3	CA	**INTANGIBLE PLANT**	INTANGPLT	49,607,381	37,090,615	128,546	216,420	3,654	56	4,760	110,106
4	CA										
5	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0
6	CA										
7	CA	**TRANSMISSION PLANT**									
8	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0
9	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
10	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
11	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0
12	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0
13	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0
14	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0
15	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0
16	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	CA										
18	CA	**DISTRIBUTION PLANT**									
19	CA	E360 Land and Land Rights	E360PLT	3,481,598	1,668,426	6,323	17,520	23	0	1,555	33,547
20	CA	E361 Structures and Improvements	E361PLT	1,433,350	715,592	3,041	7,092	18	0	798	25,805
21	CA	E362 Station Equipment	E362PLT	72,557,752	33,096,998	106,244	372,183	0	0	23,182	0
22	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	45,725,365	225,238	416,050	0	0	95,204	867,098
23	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	124,025,652	560,469	1,191,626	0	0	217,592	563,852
24	CA	E366 Underground Conduits	E367PLT	3,221,386	1,765,210	8,703	16,052	0	0	3,678	12,658
25	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	17,977,532	88,638	163,484	0	0	37,459	128,919
26	CA	E368 Line Transformers	LNTRFRMR_04	92,859,144	66,293,533	502,777	421,178	0	0	88,669	287,698
27	CA	E369 Services	E369PLT	11,962,969	7,636,864	44,738	74,744	401	6	0	0
28	CA	E370 Meters	METERPLT	73,420,491	56,940,607	183,454	306,500	48,386	755	20,836	0
29	CA	E371 Installation on Customer Premise	not_used	0	0	0	0	0	0	0	0
30	CA	E373 Street Lighting	E373PLT	39,887,684	2,620,298	13,572	23,624	10	0	3,941	27,398,679
31	CA	E374 Asset Retirement Obligations	TOTPLT								
32	CA	TOTAL DISTRIBUTION PLANT		653,152,020	358,466,077	1,743,198	3,010,053	48,838	762	492,914	29,318,255
33	CA										
34	CA	**TOTAL CAPITAL ADDITIONS**		702,759,401	395,556,693	1,871,744	3,226,472	52,492	818	497,674	29,428,361

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**								
2	CA									
3	CA	**INTANGIBLE PLANT**	INTANGPLT	2,006	510,000	8,708,646	2,559,649	213,383	52,507	7,033
4	CA									
5	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
6	CA									
7	CA	**TRANSMISSION PLANT**								
8	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
9	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
10	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
11	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
12	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
13	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
14	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
15	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
16	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	CA									
18	CA	**DISTRIBUTION PLANT**								
19	CA	E360 Land and Land Rights	E360PLT	69	10,322	790,491	635,199	158,661	159,377	84
20	CA	E361 Structures and Improvements	E361PLT	53	7,940	311,011	244,431	59,147	58,358	65
21	CA	E362 Station Equipment	E362PLT	0	0	17,315,176	14,233,170	3,666,345	3,744,454	0
22	CA	E364 Poles Towers and Fixtures	E364PLT	8,771	243,029	16,555,186	13,452,488	3,473,483	5,439,608	0
23	CA	E365 OH Conductors and Dev.	E365PLT	18,149	716,686	49,643,027	40,484,125	10,403,490	7,193,712	0
24	CA	E366 Underground Conduits	E367PLT	339	5,544	638,501	518,731	133,809	118,160	0
25	CA	E367 Underground Cond. and Dev.	E367PLT	3,454	56,459	6,502,723	5,282,945	1,362,754	1,203,380	0
26	CA	E368 Line Transformers	LNTRFRMR_04	13,113	125,329	13,001,478	12,125,371	0	0	0
27	CA	E369 Services	E369PLT	0	0	3,888,152	281,643	23,459	12,962	0
28	CA	E370 Meters	METERPLT	0	0	13,177,991	1,527,236	578,165	448,334	188,226
29	CA	E371 Installation on Customer Premise	not_used	0	0	0	0	0	0	0
30	CA	E373 Street Lighting	E373PLT	368	7,797,248	970,351	741,692	164,139	153,756	6
31	CA	E374 Asset Retirement Obligations	TOTPLT							
32	CA	TOTAL DISTRIBUTION PLANT		44,316	8,962,556	122,794,087	89,527,032	20,023,451	18,532,100	188,380
33	CA									
34	CA	**TOTAL CAPITAL ADDITIONS**		46,322	9,472,556	131,502,733	92,086,681	20,236,834	18,584,607	195,414

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AF	**ALLOCATION FACTOR TABLE**									
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AF										
4	AF	**ALLOCATION FACTORS PART A**									
5	AF										
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	2,000,647	6,950	11,612	0	0	0	0
7	AF										
8	AF										
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	2,437,470	892,509	2,865	10,036	0	0	625	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,789,384	4,227,413	13,570	47,538	0	0	2,961	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0	0	0	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,689,051	12,040,483	66,857	100,114	0	0	31,146	66,136
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	11,830,661	65,692	98,370	0	0	30,604	64,983
14	AF										
15	AF										
16	AF	**BILLING DETERMINANTS**									
17	AF										
18	AF	Number of Customers		2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
19	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	13,286,613,062	93,109,748	189,891,666	581,366	7,149	11,877,324	283,298,553
20	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0
21	AF										
22	AF										
23	AF	**ALLOCATION FACTORS PART B**									
24	AF										
25	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
26	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	0
27	AF										
28	AF										
29	AF	**ALLOCATION FACTORS PART C**									
30	AF										
31	AF	Draft EC Proforma	ECPRO_07	434,841,736	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
32	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	100	1	1	1	1	1	1
33	AF	E587 Customer Installation Expenses System	CUSINT_05	112	100	1	1	1	1	1	1
34	AF	E369 minimum Service investment- access	SERVICESMIN_03	1,445,778,695	922,949,463	5,406,749	9,033,137	48,429	755	0	0
35	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	0	0	0	0	0	0
36	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
37	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
38	AF	E370 minimum meter investment - measurement	METERSMIN_07	456,573,728	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
39	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	399,712,164	3,031,461	2,539,460	0	0	534,622	1,734,652
40	AF	Billing Function costs - cust svs	BILLING_06	130,951	94,645	329	549	6	0	7	397
41	AF	E370 excess meter investment - local delivery	METERSEXC_04	34,490,851	0	0	0	0	0	0	0
42	AF										
43	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	67,106,800	233,135	389,502	21,207	331	25,273	19,139
44	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	16,168,305	56,170	93,844	1,071	17	1,276	0
45	AF	Sales	SALES_06	0	0	0	0	0	0	0	0
46	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	2,438,140	7,794	16,634	202	2	1,125	16,667
47	AF										
48	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0
49	AF										
50	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0	0	288,392	9,532	794	195	26
7	AF									
8	AF									
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0	0	466,929	383,818	98,868	581,819	0
10	AF	CP @ primary lines - systems	CP_PRI_05	0	0	2,211,633	1,817,974	468,295	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0	0	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	3,153	32,502	3,650,708	2,944,830	753,120	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	3,098	31,936	3,587,089	2,893,512	753,120	1,139,114	0
14	AF									
15	AF									
16	AF	**BILLING DETERMINANTS**								
17	AF									
18	AF	Number of Customers		90	23,580	288,392	9,532	794	195	26
19	AF	Delivered kWh @ Meter - annual (w/n net)		15,313,401	137,520,699	7,289,563,210	10,497,945,935	3,083,571,353	4,669,504,753	672,466,899
20	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
21	AF									
22	AF									
23	AF	**ALLOCATION FACTORS PART B**								
24	AF									
25	AF	Delivery kWh @ meter	KWHMETER_04	15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
26	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0	0	7,352,369,374	0	0	0	0
27	AF									
28	AF									
29	AF	**ALLOCATION FACTORS PART C**								
30	AF									
31	AF	Draft EC Proforma	ECPRO_07	0	0	50,271,203	0	0	0	0
32	AF	E587 Customer Installation Expenses Local	CUSINT_04	1	1	1	1	1	0	1
33	AF	E587 Customer Installation Expenses System	CUSINT_05	1	1	1	1	1	0	1
34	AF	E369 minimum Service investment- access	SERVICESMIN_03	0	0	469,900,712	34,037,800	2,835,169	1,566,481	0
35	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	0	0	0	0	0
36	AF	Avg Customer Bills - local	CUSTAVG_04	90	23,580	288,392	9,532	794	195	26
37	AF	Avg Customer Bills - cust svs	CUSTAVG_06	90	23,580	288,392	9,532	794	195	26
38	AF	E370 minimum meter investment - measurement	METERSMIN_07	0	0	61,413,169	5,406,906	1,411,504	2,512,740	1,258,876
39	AF	E368 Line Transfomers - local	LNTRFRMR_04	79,064	755,659	78,391,489	73,109,064	0	0	0
40	AF	Billing Function costs - cust svs	BILLING_06	7	1,896	23,193	8,966	747	183	25
41	AF	E370 excess meter investment - local delivery	METERSEXC_04	0	0	26,737,929	4,810,153	2,456,723	486,046	0
42	AF									
43	AF	Account Maint - cust svs	ACCTMAINT_06	348	91,387	10,058,899	2,365,984	197,074	48,420	6,515
44	AF	Meter Reading Costs - measurement	MRCOST_07	0	0	3,962,103	231,110	19,250	4,730	636
45	AF	Sales	SALES_06	0	0	0	0	0	0	0
46	AF	Other Utility work by Cust Ops - local	UTILWORK_04	310	45,217	747,005	55,155	4,982	1,398	118
47	AF									
48	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
49	AF									
50	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	0	1	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	0	0	0	0	0	0	1
52	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0	0
53	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	0	0	0	0	0	0
54	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	0	0	0
58	AF										
59	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	0	0	0	0	0
60	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	3,201,035	11,121	18,579	3,047	48	1,263	0
61	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0
62	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0
63	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	0	0	0	0
64	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0
65	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0
66	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0
67	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0
68	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0
69	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0
70	AF										
71	AF										
72	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0
73	AF										
74	AF										
75	AF	**Plant Related**									
76	AF	Distribution Plant Total	DISTPLT	10,773,828,418	5,820,088,197	29,590,307	51,442,720	262,256	4,091	8,431,071	378,322,216
77	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	5,536,688,858	28,677,235	49,917,236	21,434	334	8,327,366	378,322,216
78	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	24,590,406	93,192	258,220	343	5	22,915	494,440
79	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	120,945,102	513,987	1,198,594	3,023	47	134,914	4,361,446
80	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	714,060,742	2,292,183	8,029,772	0	0	500,149	0
81	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	543,114,479	2,675,325	4,941,739	0	0	1,130,805	10,299,169
82	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	1,507,287,026	6,811,401	14,481,863	0	0	2,644,403	6,852,510
83	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	280,617,273	1,383,575	2,551,877	3	0	584,708	2,012,335
84	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	784,240,015	3,866,673	7,131,720	8	0	1,634,080	5,623,864
85	AF	Acct E369 Services	E369PLT	535,269,333	341,702,741	2,001,736	3,344,330	17,930	280	0	0
86	AF	Acct E370 Meters	METERPLT	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
87	AF										
88	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	283,399,339	913,072	1,525,483	240,822	3,757	103,705	0
89	AF	Acct E373 - Streetlights	E373PLT	499,027,153	32,782,049	169,794	295,554	127	2	49,305	342,779,606
90	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000	0.2889	0.0009	0.0032			0.0002	
91	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000	0.5462	0.0025	0.0052			0.0010	0.0017
92	AF										
93	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	30,344,677	105,166	177,058	2,989	46	3,894	90,080
94	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	86,338,967	64,496,329	223,981	377,130	6,298	97	8,588	205,683
95	AF	E391-E398 General Plant	GENPLT	429,584,593	228,514,914	1,183,591	2,060,226	885	14	343,694	15,614,435
96	AF	Common Plant	COMPLT	126,654,044	87,400,522	333,738	567,199	6,907	107	35,966	1,435,377
97	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	315,915,436	1,517,329	2,627,425	7,792	120	379,660	17,049,812
98	AF										
99	AF	Total Plant	TOTPLT	11,456,990,950	6,230,844,640	31,436,784	54,624,332	279,335	4,355	8,823,214	395,667,792
100	AF										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AF	Direct - BPL - streetlighting	DIR_BPL_02	0	0	0	0	0	0	0
52	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0
53	AF	Direct - HTS-HV - access	DIR_HTSHV_03	0	0	0	0	0	0	1
54	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	0	0
58	AF									
59	AF	Direct - HTS-Sub - local	DIR_HTSS_04	0	0	0	0	0	1	0
60	AF	Meter O&M - minimum - measurement	MTROMMIN_07	0	0	441,272	2,449,831	204,058	50,136	6,746
61	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
62	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
63	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	0	0	0
64	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
65	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0
66	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
67	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
68	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
69	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
70	AF									
71	AF									
72	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
73	AF									
74	AF									
75	AF	**Plant Related**								
76	AF	Distribution Plant Total	DISTPLT	778,473	116,404,096	2,115,939,717	1,574,796,259	349,702,577	327,117,359	949,079
77	AF	Distribution Plant x meters	DISTPLTXMTR	778,473	116,404,096	2,050,351,482	1,567,195,044	346,824,988	324,885,954	12,261
78	AF	Acct E360 - Land & Land Rights	E360PLT	1,017	152,132	11,650,793	9,362,003	2,338,448	2,349,013	1,240
79	AF	Acct E361 - Structures & Improvments	E361PLT	8,975	1,341,952	52,565,192	41,312,252	9,996,655	9,863,367	10,941
80	AF	Acct E362 - Station Equipment	E362PLT	0	0	373,571,272	307,077,645	79,100,612	80,785,795	0
81	AF	Acct E364 - Poles & Towers	E364PLT	104,180	2,886,640	196,638,373	159,785,302	41,257,161	64,610,311	0
82	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	220,559	8,709,908	603,313,016	492,004,642	126,433,892	87,425,369	0
83	AF	Acct E366 - UG Conduit	E366PLT	53,911	881,281	101,503,167	82,463,239	21,271,683	18,783,951	2
84	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	150,665	2,462,911	283,670,511	230,459,698	59,447,890	52,495,436	5
85	AF	Acct E369 Services	E369PLT	0	0	173,970,914	12,601,784	1,049,662	579,957	0
86	AF	Acct E370 Meters	METERPLT	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
87	AF									
88	AF	Acct E370 Meters x load profile meters	METERPLTXPR	0	0	65,588,236	7,601,215	2,877,589	2,231,405	936,819
89	AF	Acct E373 - Streetlights	E373PLT	4,609	97,549,871	12,139,877	9,279,168	2,053,508	1,923,610	73
90	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES			0.1511	0.1242	0.0320	0.3993	
91	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.0001	0.0008	0.2185	0.1782	0.0458		
92	AF									
93	AF	Acct E301-E303 Intangible Plt	INTANGPLT	1,641	417,243	7,124,741	2,094,107	174,573	42,957	5,754
94	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	3,459	875,602	15,188,498	4,454,551	381,537	105,174	12,038
95	AF	E391-E398 General Plant	GENPLT	32,130	4,804,328	84,623,844	64,682,602	14,314,455	13,408,968	506
96	AF	Common Plant	COMPLT	6,284	1,332,635	22,959,377	9,882,482	1,526,297	1,153,953	13,202
97	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	38,413	6,136,963	107,583,221	74,565,084	15,840,751	14,562,921	13,708
98	AF									
99	AF	Total Plant	TOTPLT	821,986	123,833,904	2,245,836,177	1,655,910,001	366,099,439	341,828,412	980,578
100	AF									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	1,730,330,862	8,737,683	14,901,854	107,752	1,679	2,361,921	97,434,992
102	AF	Total Net Plant	TOTPLTNET	8,357,658,252	4,500,513,778	22,699,101	39,722,478	171,583	2,675	6,461,292	298,232,800
103	AF										
104	AF										
105	AF	**Revenue Related**									
106	AF	Total Operating Revenue	TOTREV	1,887,985,784	1,070,592,616	4,993,518	8,845,571	133,897	2,086	1,301,354	63,762,201
107	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
108	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
109	AF										
110	AF	**Expense Related**									
111	AF	Distr Oper Exp	DISTEXPO	52,242,807	23,912,641	105,368	221,695	6,574	103	38,573	472,417
112	AF	Distr Maint Exp	DISTEXPM	123,204,777	57,907,160	260,376	557,434	492	8	90,243	8,510,628
113	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
114	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
115	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	74,553,054	258,380	435,009	7,344	113	9,567	221,316
116	AF	Sales Expense	SALESEXP	40,922	29,919	96	204	2	0	14	205
117	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	174,029,579	750,500	1,425,184	12,768	198	187,534	10,354,358
118	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	64,994,603	308,106	540,267	5,470	85	80,178	4,010,634
119	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	70,356,872	244,210	409,157	6,408	100	7,918	209,752
120	AF	O&M + Capital Additions	EXPENDITURES	1,014,217,038	569,586,272	2,622,244	4,651,657	65,260	1,016	685,208	39,782,720
121	AF										
122	AF	Depreciation Expense (total)	DEPREXP	286,771,855	156,133,565	786,764	1,366,959	6,818	106	220,165	9,875,199
123	AF										
124	AF	NJ State Income Tax (CBT)	STATEINCTAX	116,400,498	64,842,495	315,649	551,521	7,312	114	86,720	4,008,952
125	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	2,766,183	1,804,209	6,398	11,771	318	5	853	108,620
126	AF										
127	AF	**Labor Expense Related**									
128	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	27,494,585	107,058	195,722	8,974	140	25,248	205,461
129	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	20,286,632	94,038	191,256	370	6	31,250	5,548,783
130	AF	Total Labor	LABOR	159,006,836	99,248,713	383,577	696,150	14,587	226	67,268	6,103,206
131	AF										
132	AF	**REVENUES AND BILLING DETERMINANTS**									
133	AF										
134	AF	Base Rate Sales Revenue	SALESREV	1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
135	AF										
136	AF	Residential Service	REVRS	1,058,428,504	1,058,428,504	0	0	0	0	0	0
137	AF	Residential Heating Service	REVRHS	4,936,781	0	4,936,781	0	0	0	0	0
138	AF	Residential Load Management Service	REVRLM	8,745,067	0	0	8,745,067	0	0	0	0
139	AF	Water Heating Service	REVWH	132,375	0	0	0	132,375	0	0	0
140	AF	Water Heating Storage Service	REVWHS	2,062	0	0	0	0	2,062	0	0
141	AF	Building Heating Service	REVHS	1,280,136	0	0	0	0	0	1,280,136	0
142	AF	Body Police Lighting Service	REVBLP	63,037,732	0	0	0	0	0	0	63,037,732
143	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	501,853	0	0	0	0	0	0	0
144	AF	Private Street and Area Lighting Service	REVPAL	22,396,231	0	0	0	0	0	0	0
145	AF	General Power and Lighting Service	REVGLP	349,056,779	0	0	0	0	0	0	0
146	AF	Large Power and Lighting Service - Secondary	REVLPLS	250,012,787	0	0	0	0	0	0	0
147	AF	Large Power and Lighting Service - Primary	REVLPLP	54,689,734	0	0	0	0	0	0	0
148	AF	High Tension Service - Subtransmission	REVHTSS	49,480,290	0	0	0	0	0	0	0
149	AF	High Tension Service - High Voltage	REVHTSHV	181,014	0	0	0	0	0	0	0
150	AF	HEP	REVHEP	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AF	Total Distribution Plant Reserve	TOTDRESERVE	223,683	31,039,060	616,155,185	420,676,004	92,737,788	84,253,932	370,301
102	AF	Total Net Plant	TOTPLTNET	598,304	92,794,843	1,629,680,992	1,235,233,997	273,361,651	257,574,480	610,278
103	AF									
104	AF									
105	AF	**Revenue Related**								
106	AF	Total Operating Revenue	TOTREV	507,620	22,767,438	354,842,239	254,156,637	55,596,191	50,300,403	184,015
107	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**								
108	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
109	AF									
110	AF	**Expense Related**								
111	AF	Distr Oper Exp	DISTEXPO	2,805	98,798	8,974,334	14,259,747	2,425,247	1,704,800	19,707
112	AF	Distr Maint Exp	DISTEXPM	347,352	3,961,344	23,427,630	19,436,252	4,785,399	3,919,255	1,205
113	AF	Cust Serv & Info Expense	CUSTS_I	214	34,498	876,964	140,606	11,945	3,040	367
114	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
115	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	4,032	1,025,113	17,504,593	5,144,958	428,905	105,541	14,137
116	AF	Sales Expense	SALESEXP	4	555	9,167	677	61	17	1
117	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	364,091	5,252,980	59,033,027	42,782,536	9,532,172	7,696,917	35,792
118	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	10,926	1,367,587	21,699,832	12,228,322	3,356,616	3,048,461	11,019
119	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	3,818	990,615	16,627,629	5,004,352	416,960	102,501	13,770
120	AF	O&M + Capital Additions	EXPENDITURES	410,413	14,725,536	190,535,760	134,869,217	29,769,006	26,281,524	231,206
121	AF									
122	AF	Depreciation Expense (total)	DEPREXP	20,562	3,103,283	56,193,328	41,376,181	9,137,198	8,528,035	23,691
123	AF									
124	AF	NJ State Income Tax (CBT)	STATEINCTAX	11,428	1,262,650	22,143,408	16,202,860	3,589,532	3,368,164	9,692
125	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	152	49,020	439,306	274,744	43,612	26,751	424
126	AF									
127	AF	**Labor Expense Related**								
128	AF	Total Distribution Exp (Oper) Labor	TLABDO	2,142	214,391	6,353,567	7,073,763	1,135,727	776,176	10,847
129	AF	Total Distribution Exp (Maint) Labor	TLABDM	4,072	1,621,488	7,947,525	6,732,602	1,591,166	1,367,165	862
130	AF	Total Labor	LABOR	9,374	2,558,220	26,671,410	17,694,261	3,171,428	2,367,194	21,221
131	AF									
132	AF	**REVENUES AND BILLING DETERMINANTS**								
133	AF									
134	AF	Base Rate Sales Revenue	SALESREV	501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
135	AF									
136	AF	Residential Service	REVRS	0	0	0	0	0	0	0
137	AF	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
138	AF	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
139	AF	Water Heating Service	REVWH	0	0	0	0	0	0	0
140	AF	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
141	AF	Building Heating Service	REVHS	0	0	0	0	0	0	0
142	AF	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
143	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	501,853	0	0	0	0	0	0
144	AF	Private Street and Area Lighting Service	REVPAL	0	22,396,231	0	0	0	0	0
145	AF	General Power and Lighting Service	REVGLP	0	0	349,056,779	0	0	0	0
146	AF	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	250,012,787	0	0	0
147	AF	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	54,689,734	0	0
148	AF	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	49,480,290	0
149	AF	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	181,014
150	AF	HEP	REVHEP	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AF										
152	AF										
153	AF	Total Rev Req @ desired ROR	REVREQ	1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
154	AF										
155	AF										
156	AF	**PRESENT REVENUES FROM SALES INPUT**									
157	AF										
158	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0
159	AF	Sales of Electricity Revenues - Rates		1,254,696,745	597,284,000	4,407,000	7,778,000	52,355	161	740,000	56,059,000
160	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0
161	AF										
162	AF	**RATE OF RETURN**									
163	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
164	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0
165	AF	Expense Reclassification-local	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AF									
152	AF									
153	AF	Total Rev Req @ desired ROR	REVREQ	501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
154	AF									
155	AF									
156	AF	**PRESENT REVENUES FROM SALES INPUT**								
157	AF									
158	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
159	AF	Sales of Electricity Revenues - Rates		322,229	27,815,000	264,859,000	223,909,000	38,961,000	30,175,000	2,335,000
160	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
161	AF									
162	AF	**RATE OF RETURN**								
163	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
164	AF	Expense Reclassification Plus-local	ADJ_Plus_04	0	0	0	0	0	0	10,316
165	AF	Expense Reclassification-local	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AP	**ALLOCATION PROPORTIONS TABLE**									
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AP										
4	AP	**ALLOCATION FACTORS PART A**									
5	AP										
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.863036	0.002998	0.005009	0.000000	0.000000	0.000000	0.000000
7	AP										
8	AP										
9	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.366162	0.001175	0.004118	0.000000	0.000000	0.000256	0.000000
10	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.480968	0.001544	0.005409	0.000000	0.000000	0.000337	0.000000
11	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.611532	0.003396	0.005085	0.000000	0.000000	0.001582	0.003359
13	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.577157	0.003205	0.004799	0.000000	0.000000	0.001493	0.003170
14	AP										
15	AP	**BILLING DETERMINANTS**									
16	AP										
17	AP	Number of Customers									
18	AP	Delivered kWh @ Meter - annual (w/n net)									
19	AP	Delivered Kw @ Meter - annual									
20	AP										
21	AP	**ALLOCATION FACTORS PART B**									
22	AP										
23	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.335298	0.002290	0.004780	0.000014	0.000000	0.000291	0.006941
24	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.641341	0.004380	0.009143	0.000027	0.000000	0.000557	0.000000
25	AP										
26	AP										
27	AP	**ALLOCATION FACTORS PART C**									
28	AP										
29	AP	Draft EC Proforma	ECPRO_07	1.000000	0.875780	0.002822	0.004714	0.000744	0.000012	0.000320	0.000000
30	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
31	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
32	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.638375	0.003740	0.006248	0.000033	0.000001	0.000000	0.000000
33	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
35	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
36	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.834095	0.002687	0.004490	0.000709	0.000011	0.000305	0.000000
37	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.713915	0.005414	0.004536	0.000000	0.000000	0.000955	0.003098
38	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.722749	0.002511	0.004195	0.000048	0.000001	0.000057	0.003033
39	AP	E370 excess meter investment - local delivery	METERSEXC_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	AP										
41	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.832962	0.002894	0.004835	0.000263	0.000004	0.000314	0.000238
42	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.787219	0.002735	0.004569	0.000052	0.000001	0.000062	0.000000
43	AP										
44	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
46	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	AP										
48	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
50	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0.000000	0.000000	0.124406	0.004112	0.000343	0.000084	0.000011
7	AP									
8	AP									
9	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0.000000	0.000000	0.191563	0.157466	0.040562	0.238698	0.000000
10	AP	CP @ primary lines - systems	CP_PRI_05	0.000000	0.000000	0.251625	0.206837	0.053280	0.000000	0.000000
11	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	0.000160	0.001651	0.185418	0.149567	0.038251	0.000000	0.000000
13	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	0.000151	0.001558	0.174996	0.141159	0.036741	0.055571	0.000000
14	AP									
15	AP	**BILLING DETERMINANTS**								
16	AP									
17	AP	Number of Customers								
18	AP	Delivered kWh @ Meter - annual (w/n net)								
19	AP	Delivered Kw @ Meter - annual								
20	AP									
21	AP	**ALLOCATION FACTORS PART B**								
22	AP									
23	AP	Delivery kWh @ meter	KWHMETER_04	0.000375	0.003369	0.180134	0.259443	0.076184	0.114404	0.016476
24	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0.000000	0.000000	0.344551	0.000000	0.000000	0.000000	0.000000
25	AP									
26	AP									
27	AP	**ALLOCATION FACTORS PART C**								
28	AP									
29	AP	Draft EC Proforma	ECPRO_07	0.000000	0.000000	0.115608	0.000000	0.000000	0.000000	0.000000
30	AP	E587 Customer Installation Expenses Local	CUSINT_04	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
31	AP	E587 Customer Installation Expenses System	CUSINT_05	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
32	AP	E369 minimum Service investment- access	SERVICESMIN_03	0.000000	0.000000	0.325016	0.023543	0.001961	0.001083	0.000000
33	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Avg Customer Bills - local	CUSTAVG_04	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
35	AP	Avg Customer Bills - cust svs	CUSTAVG_06	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
36	AP	E370 minimum meter investment - measurement	METERSMIN_07	0.000000	0.000000	0.134509	0.011842	0.003092	0.005503	0.002757
37	AP	E368 Line Transfomers - local	LNTRFRMR_04	0.000141	0.001350	0.140013	0.130578	0.000000	0.000000	0.000000
38	AP	Billing Function costs - cust svs	BILLING_06	0.000055	0.014481	0.177112	0.068465	0.005703	0.001401	0.000189
39	AP	E370 excess meter investment - local delivery	METERSEXC_04	0.000000	0.000000	0.775218	0.139462	0.071228	0.014092	0.000000
40	AP									
41	AP	Account Maint - cust svs	ACCTMAINT_06	0.000004	0.001134	0.124856	0.029368	0.002446	0.000601	0.000081
42	AP	Meter Reading Costs - measurement	MRCOST_07	0.000000	0.000000	0.192911	0.011253	0.000937	0.000230	0.000031
43	AP									
44	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	AP	Other Utility work by Cust Ops - local	UTILWORK_04	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
46	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	AP									
48	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Direct - BPL - streetlighting	DIR_BPL_02	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
50	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP										
55	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AP										
58	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
59	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.501169	0.001741	0.002909	0.000477	0.000007	0.000198	0.000000
60	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP										
70	AP										
71	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
72	AP										
73	AP	**Plant Related**									
74	AP	Distribution Plant Total	DISTPLT	1.000000	0.540206	0.002746	0.004775	0.000024	0.000000	0.000783	0.035115
75	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.531944	0.002755	0.004796	0.000002	0.000000	0.000800	0.036348
76	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.479213	0.001816	0.005032	0.000007	0.000000	0.000447	0.009636
77	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.499244	0.002122	0.004948	0.000012	0.000000	0.000557	0.018003
78	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.456147	0.001464	0.005129	0.000000	0.000000	0.000319	0.000000
79	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.528608	0.002604	0.004810	0.000000	0.000000	0.001101	0.010024
80	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.527727	0.002385	0.005070	0.000000	0.000000	0.000926	0.002399
81	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.547966	0.002702	0.004983	0.000000	0.000000	0.001142	0.003930
82	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.547966	0.002702	0.004983	0.000000	0.000000	0.001142	0.003930
83	AP	Acct E369 Services	E369PLT	1.000000	0.638375	0.003740	0.006248	0.000033	0.000001	0.000000	0.000000
84	AP	Acct E370 Meters	METERPLT	1.000000	0.775541	0.002499	0.004175	0.000659	0.000010	0.000284	0.000000
85	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.775541	0.002499	0.004175	0.000659	0.000010	0.000284	0.000000
86	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.065692	0.000340	0.000592	0.000000	0.000000	0.000099	0.686896
87	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.288902	0.000927	0.003249	0.000000	0.000000	0.000202	0.000000
88	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.546250	0.002470	0.005247	0.000000	0.000000	0.000959	0.001680
89	AP										
90	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.747683	0.002591	0.004363	0.000074	0.000001	0.000096	0.002220
91	AP										
92	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.747013	0.002594	0.004368	0.000073	0.000001	0.000099	0.002382
93	AP	E391-E398 General Plant	GENPLT	1.000000	0.531944	0.002755	0.004796	0.000002	0.000000	0.000800	0.036348
94	AP	Common Plant	COMPLT	1.000000	0.690073	0.002635	0.004478	0.000055	0.000001	0.000284	0.011333
95	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.567949	0.002728	0.004724	0.000014	0.000000	0.000683	0.030652
96	AP										
97	AP	Total Plant	TOTPLT	1.000000	0.543847	0.002744	0.004768	0.000024	0.000000	0.000770	0.034535
98	AP										
99	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.558291	0.002819	0.004808	0.000035	0.000001	0.000762	0.031437
100	AP	Total Net Plant	TOTPLTNET	1.000000	0.538490	0.002716	0.004753	0.000021	0.000000	0.000773	0.035684

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AP	Direct - HTS-HV - access	DIR_HTSHV_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
52	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP									
55	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AP									
58	AP	Direct - HTS-Sub - local	DIR_HTSS_04	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
59	AP	Meter O&M - minimum - measurement	MTROMMIN_07	0.000000	0.000000	0.069088	0.383557	0.031948	0.007850	0.001056
60	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP									
70	AP									
71	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
72	AP									
73	AP	**Plant Related**								
74	AP	Distribution Plant Total	DISTPLT	0.000072	0.010804	0.196396	0.146169	0.032459	0.030362	0.000088
75	AP	Distribution Plant x meters	DISTPLTXMTR	0.000075	0.011184	0.196990	0.150570	0.033322	0.031214	0.000001
76	AP	Acct E360 - Land & Land Rights	E360PLT	0.000020	0.002965	0.227048	0.182445	0.045571	0.045777	0.000024
77	AP	Acct E361 - Structures & Improvments	E361PLT	0.000037	0.005539	0.216982	0.170531	0.041265	0.040715	0.000045
78	AP	Acct E362 - Station Equipment	E362PLT	0.000000	0.000000	0.238640	0.196163	0.050530	0.051607	0.000000
79	AP	Acct E364 - Poles & Towers	E364PLT	0.000101	0.002810	0.191386	0.155517	0.040155	0.062885	0.000000
80	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	0.000077	0.003049	0.211230	0.172259	0.044267	0.030609	0.000000
81	AP	Acct E366 - UG Conduit	E366PLT	0.000105	0.001721	0.198207	0.161027	0.041538	0.036680	0.000000
82	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	0.000105	0.001721	0.198207	0.161027	0.041538	0.036680	0.000000
83	AP	Acct E369 Services	E369PLT	0.000000	0.000000	0.325016	0.023543	0.001961	0.001083	0.000000
84	AP	Acct E370 Meters	METERPLT	0.000000	0.000000	0.179487	0.020801	0.007875	0.006106	0.002564
85	AP	Acct E370 Meters x load profile meters	METERPLTXPR	0.000000	0.000000	0.179487	0.020801	0.007875	0.006106	0.002564
86	AP	Acct E373 - Streetlights	E373PLT	0.000009	0.195480	0.024327	0.018595	0.004115	0.003855	0.000000
87	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	0.000000	0.000000	0.151143	0.124241	0.032003	0.399333	0.000000
88	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.000080	0.000825	0.218522	0.178202	0.045765	0.000000	0.000000
89	AP									
90	AP	Acct E301-E303 Intangible Plt	INTANGPLT	0.000040	0.010281	0.175551	0.051598	0.004301	0.001058	0.000142
91	AP									
92	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000040	0.010141	0.175917	0.051594	0.004419	0.001218	0.000139
93	AP	E391-E398 General Plant	GENPLT	0.000075	0.011184	0.196990	0.150570	0.033322	0.031214	0.000001
94	AP	Common Plant	COMPLT	0.000050	0.010522	0.181276	0.078027	0.012051	0.009111	0.000104
95	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	0.000069	0.011033	0.193412	0.134052	0.028478	0.026181	0.000025
96	AP									
97	AP	Total Plant	TOTPLT	0.000072	0.010809	0.196023	0.144533	0.031954	0.029836	0.000086
98	AP									
99	AP	Total Distribution Plant Reserve	TOTDRESERVE	0.000072	0.010015	0.198803	0.135731	0.029922	0.027185	0.000119
100	AP	Total Net Plant	TOTPLTNET	0.000072	0.011103	0.194993	0.147797	0.032708	0.030819	0.000073

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AP										
102	AP										
103	AP	**Revenue Related**									
104	AP	Total Operating Revenue	TOTREV	1.000000	0.567055	0.002645	0.004685	0.000071	0.000001	0.000689	0.033773
105	AP										
106	AP										
107	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
108	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
109	AP										
110	AP	**Expense Related**									
111	AP	Distr Oper Exp	DISTEXPO	1.000000	0.457721	0.002017	0.004244	0.000126	0.000002	0.000738	0.009043
112	AP	Distr Maint Exp	DISTEXPM	1.000000	0.470007	0.002113	0.004524	0.000004	0.000000	0.000732	0.069077
113	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.789053	0.002665	0.004861	0.000176	0.000003	0.000310	0.002174
114	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.745353	0.002587	0.004335	0.000068	0.000001	0.000084	0.002222
115	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.747683	0.002591	0.004363	0.000074	0.000001	0.000096	0.002220
116	AP	Sales Expense	SALESEXP	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
117	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.558758	0.002410	0.004576	0.000041	0.000001	0.000602	0.033245
118	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.582065	0.002759	0.004838	0.000049	0.000001	0.000718	0.035918
119	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.745353	0.002587	0.004335	0.000068	0.000001	0.000084	0.002222
120	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.561602	0.002585	0.004586	0.000064	0.000001	0.000676	0.039225
121	AP										
122	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.544452	0.002744	0.004767	0.000024	0.000000	0.000768	0.034436
123	AP										
124	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.557064	0.002712	0.004738	0.000063	0.000001	0.000745	0.034441
125	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.652238	0.002313	0.004255	0.000115	0.000002	0.000308	0.039267
126	AP										
127	AP	**Labor Expense Related**									
128	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.630555	0.002455	0.004489	0.000206	0.000003	0.000579	0.004712
129	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.446673	0.002071	0.004211	0.000008	0.000000	0.000688	0.122174
130	AP	Total Labor	LABOR	1.000000	0.624179	0.002412	0.004378	0.000092	0.000001	0.000423	0.038383
131	AP										
132	AP	**REVENUES AND BILLING DETERMINANTS**									
133	AP										
134	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.568167	0.002650	0.004694	0.000071	0.000001	0.000687	0.033839
135	AP										
136	AP	Residential Service	REVRS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
137	AP	Residential Heating Service	REVRHS	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
138	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
139	AP	Water Heating Service	REVWH	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
140	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
141	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
142	AP	Body Police Lighting Service	REVBLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
143	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
144	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
145	AP										
146	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
147	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
148	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
149	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
150	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AP									
102	AP									
103	AP	**Revenue Related**								
104	AP	Total Operating Revenue	TOTREV	0.000269	0.012059	0.187948	0.134618	0.029447	0.026642	0.000097
105	AP									
106	AP									
107	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
108	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
109	AP									
110	AP	**Expense Related**								
111	AP	Distr Oper Exp	DISTEXPO	0.000054	0.001891	0.171781	0.272951	0.046423	0.032632	0.000377
112	AP	Distr Maint Exp	DISTEXPM	0.002819	0.032153	0.190152	0.157756	0.038841	0.031811	0.000010
113	AP	Cust Serv & Info Expense	CUSTS_I	0.000040	0.006487	0.164905	0.026440	0.002246	0.000572	0.000069
114	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	0.000040	0.010494	0.176151	0.053016	0.004417	0.001086	0.000146
115	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	0.000040	0.010281	0.175551	0.051598	0.004301	0.001058	0.000142
116	AP	Sales Expense	SALESEXP	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
117	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	0.001169	0.016866	0.189538	0.137362	0.030605	0.024713	0.000115
118	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	0.000098	0.012248	0.194335	0.109512	0.030060	0.027301	0.000099
119	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	0.000040	0.010494	0.176151	0.053016	0.004417	0.001086	0.000146
120	AP	O&M + Capital Additions	EXPENDITURES	0.000405	0.014519	0.187865	0.132979	0.029352	0.025913	0.000228
121	AP									
122	AP	Depreciation Expense (total)	DEPREXP	0.000072	0.010821	0.195951	0.144283	0.031862	0.029738	0.000083
123	AP									
124	AP	NJ State Income Tax (CBT)	STATEINCTAX	0.000098	0.010847	0.190235	0.139199	0.030838	0.028936	0.000083
125	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	0.000055	0.017721	0.158813	0.099323	0.015766	0.009671	0.000153
126	AP									
127	AP	**Labor Expense Related**								
128	AP	Total Distribution Exp (Oper) Labor	TLABDO	0.000049	0.004917	0.145711	0.162228	0.026047	0.017801	0.000249
129	AP	Total Distribution Exp (Maint) Labor	TLABDM	0.000090	0.035702	0.174989	0.148239	0.035034	0.030102	0.000019
130	AP	Total Labor	LABOR	0.000059	0.016089	0.167738	0.111280	0.019945	0.014887	0.000133
131	AP									
132	AP	**REVENUES AND BILLING DETERMINANTS**								
133	AP									
134	AP	Base Rate Sales Revenue	SALESREV	0.000269	0.012022	0.187375	0.134208	0.029358	0.026561	0.000097
135	AP									
136	AP	Residential Service	REVRS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
137	AP	Residential Heating Service	REVRHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
138	AP	Residential Load Management Service	REVRLM	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
139	AP	Water Heating Service	REVWH	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
140	AP	Water Heating Storage Service	REVWHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
141	AP	Building Heating Service	REVHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
142	AP	Body Police Lighting Service	REVBLP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
143	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
144	AP	Private Street and Area Lighting Service	REVPAL	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
145	AP									
146	AP	General Power and Lighting Service	REVGLP	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
147	AP	Large Power and Lighting Service - Secondary	REVLPLS	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
148	AP	Large Power and Lighting Service - Primary	REVLPLP	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
149	AP	High Tension Service - Subtransmission	REVHTSS	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
150	AP	High Tension Service - High Voltage	REVHTSHV	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
152	AP										
153	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.568167	0.002650	0.004694	0.000071	0.000001	0.000687	0.033839
154	AP										
155	AP	**PRESENT REVENUES FROM SALES INPUT**									
156	AP										
157	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Sales of Electricity Revenues - Rates		1.000000	0.476039	0.003512	0.006199	0.000042	0.000000	0.000590	0.044679
159	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	0.000000	0.406337	0.006306	0.000000	0.000000
161	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.624242	0.002413	0.004379	0.000000	0.000000	0.000423	0.038400

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
152	AP									
153	AP	Total Rev Req @ desired ROR	REVREQ	0.000269	0.012022	0.187375	0.134208	0.029358	0.026561	0.000097
154	AP									
155	AP	**PRESENT REVENUES FROM SALES INPUT**								
156	AP									
157	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Sales of Electricity Revenues - Rates		0.000257	0.022169	0.211094	0.178457	0.031052	0.024050	0.001861
159	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Expense Reclassification Plus-local	ADJ_Plus_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.587357
161	AP	Expense Reclassification-local	ADJEXP_04	0.000059	0.016095	0.167800	0.111337	0.019957	0.014895	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
3	ADA										
4	ADA	**Net Write-Offs**									
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
20	ADA										
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0
22	ADA										
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA										
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0
26	ADA										
27	ADA										
28	ADA	**Rev to Customers w/Late Payment fees**									
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	1,280,136	0	0	0	0	0	1,280,136	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	22,396,231	0	0	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	349,056,779	0	0	0	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	250,012,787	0	0	0	0	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	54,689,734	0	0	0	0	0	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	49,480,290	0	0	0	0	0	0	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	181,014	0	0	0	0	0	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
44	ADA										
45	ADA	Total Late Payment Fees	REVLATEP	727,096,970	0	0	0	0	0	1,280,136	0
46	ADA	Total Late Payment Fees	REVLATEP	1.000000						0.001761	
47	ADA										
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS									
50	ADA										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	0	22,396,231	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	0	0	349,056,779	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	250,012,787	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	54,689,734	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	49,480,290	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	181,014
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									
45	ADA	Total Late Payment Fees	REVLATEP	0	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
46	ADA	Total Late Payment Fees	REVLATEP		0.030802	0.480069	0.343851	0.075217	0.068052	0.000249
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	ADA	**AVAILABLE**									
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
67	ADA										
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RRW	**REVENUE REQUIREMENTS**									
2	RRW										
3	RRW	PRESENT RATES									
4	RRW	----------									
5	RRW	RATE BASE		9,635,540,505	5,433,120,523	26,081,061	45,565,460	729,937	11,384	7,045,925	326,456,069
6	RRW	NET OPER INC (PRESENT RATES)		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
10	RRW	REVENUE PRES RATES $/KWH		$0.0456	$0.0773	$0.0528	$0.0448	$0.2264	$0.2884	$0.1077	$0.2225
11	RRW	REVENUE REQUIRED - $/MO/CUST		$66.11	$44.09	$59.19	$62.76	$16.65	$16.63	$135.14	$1,063.78
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW										
14	RRW	CLAIMED RATE OF RETURN									
15	RRW	----------									
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		711,102,889	400,964,295	1,924,782	3,362,731	53,869	840	519,989	24,092,458
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,862,881,345	1,058,428,504	4,936,781	8,745,067	132,375	2,062	1,280,136	63,037,732
19	RRW	REVENUE DEFICIENCY SALES REV		0							
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
22	RRW	SALES REV REQUIRED $/KWH		$0.0456	$0.0773	$0.0528	$0.0448	$0.2264	$0.2884	$0.1077	$0.2225
23	RRW	REVENUE DEFICIENCY $/KWH									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	----------								
5	RRW	RATE BASE		1,022,124	103,915,941	1,816,712,160	1,311,785,994	290,219,052	272,047,354	827,520
6	RRW	NET OPER INC (PRESENT RATES)		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
10	RRW	REVENUE PRES RATES $/KWH		$0.0328	$0.1629	$0.0475	$0.0236	$0.0176	$0.0106	$0.0003
11	RRW	REVENUE REQUIRED - $/MO/CUST		$465.54	$79.15	$100.86	$2,185.64	$5,739.90	$21,136.39	$574.65
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	----------								
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		75,433	7,668,996	134,073,357	96,809,806	21,418,166	20,077,095	61,071
18	RRW	SALES REVENUE REQ CLAIMED ROR		501,853	22,396,231	349,056,779	250,012,787	54,689,734	49,480,290	181,014
19	RRW	REVENUE DEFICIENCY SALES REV				0	(0)			
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
22	RRW	SALES REV REQUIRED $/KWH		$0.0328	$0.1629	$0.0475	$0.0236	$0.0176	$0.0106	$0.0003
23	RRW	REVENUE DEFICIENCY $/KWH								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	0	0	0	125,606,741	0	0
10	S	Station Equipment E362	CALCULATED	1,565,418,169	0	0	0	669,777,783	0	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0
13	S	UG Conductors E366	CALCULATED	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0
15	S	Line Transformers E368	CALCULATED	1,591,690,631	0	0	756,053,050	0	0	0
16	S	Services E369	CALCULATED	535,269,333	0	535,269,333	0	0	0	0
17	S	Meters E370	CALCULATED	365,421,442	0	0	122,177,671	0	0	76,316,914
18	S	Street Lighting E373	CALCULATED	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	932,488	0	30,447,221	13,034,833	0	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914
22	S	General Plant E389-E399	CALCULATED	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0
23	S	Common Plant C389-C399	CALCULATED	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589
25	S	Total Plant in Service	CALCULATED	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	1,153,424,258	63,830,655	19,921,829	248,313,802	184,777,469	70,384,500	46,999,741
30	S	Plant Held for Future Use	CALCULATED	495,177	22,138	24,349	115,708	85,853	5,981	4,800
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,015,996,645	61,220,311	62,612,913	315,548,459	238,042,456	4,631,514	683,436,361
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-63,735,780	-2,837,691	-1,886,245	-12,528,067	-10,173,104	-4,124,283	-5,557,527
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,800,404,102	-79,935,371	-88,010,271	-417,605,067	-309,970,064	-33,113,358	-19,416,826
37	S									
38	S									
39	S	Other Rate Base Deductions		-27,893,945	-84,606	0	-6,602,796	-6,435,633	0	0
40	S	TOTAL RATE BASE		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982
41	S									
42	S									
43	S									
44	S									
45	S	**SUMMARY OF RESULTS**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	S	**DEVELOPMENT OF RETURN**	CALCULATED							
47	S									
48	S	**RATE BASE**	CALCULATED	9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982
49	S									
50	S	**OPERATING REVENUES**								
51	S	Rate Revenues from Customers	CALCULATED	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
52	S	Other Operating Revenues	CALCULATED	25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219
53	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
54	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
55	S	TOTAL OPERATING REVENUES		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675
56	S									
57	S	**OPERATING EXPENSES**								
58	S	Operation and Maintenance Expense								
59	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
60	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
61	S	Distribution Expense	CALCULATED	178,009,259	13,223,105	74,179	23,979,432	38,515,543	0	18,936,951
62	S	Customer Accounts Expense	CALCULATED	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636
63	S	Customer Service & Information Expense	CALCULATED	5,318,001	0	0	2,010,317	0	3,307,684	0
64	S	Sales Expense	CALCULATED	40,922	0	0	40,922	0	0	0
65	S	Administrative and General Expense	CALCULATED	33,695,393	1,396,765	4,468,813	15,985,344	11,202,679	-18,612,894	-13,577,262
66	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325
67	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796
68	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152
69	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799
70	S	Proforma Expense Adjustments	CALCULATED	83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614
71	S	State Income Taxes	CALCULATED	116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848
72	S	Federal Income Taxes	CALCULATED	224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531
73	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		1,176,882,895	52,399,564	33,385,741	218,927,975	181,321,345	115,381,185	107,862,349
77	S									
78	S	**OPERATING INCOME (RETURN)**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326
79	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
80	S	TOTAL NET OPERATING INCOME		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326
81	S									
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
84	S									
85	S	**EQUALIZED RETURN AT PROPOSED ROR**								
86	S									
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**								
88	S									
89	S	**RATE BASE**	CALCULATED	9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982
90	S									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
92	S									
93	S	**RETURN (RATE BASE * 7.40% ROR)**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326
94	S									
95	S	**PLUS:**	CALCULATED							
96	S	**OPERATING EXPENSES**								
97	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325
98	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796
99	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152
100	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799
101	S	Proforma Expense Adjustments	CALCULATED	83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614
102	S	Income Taxes	CALCULATED	340,725,434	15,350,240	11,268,169	74,523,415	58,750,263	1,285,576	22,257,379
103	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
106	S	**TOTAL OPERATING EXPENSES**		1,176,882,895	52,399,564	33,385,741	218,927,975	181,321,345	115,381,185	107,862,349
107	S									
108	S	**EQUALS TOTAL COST OF SERVICE**		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675
109	S									
110	S	**LESS:**								
111	S	Other Operating Revenues	CALCULATED	25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
114	S	**EQUALS:**								
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
116	S									
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00
119	S									
120	S									
121	S									
122	S									
123	S									
124	S									
125	S									
126	S									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	E362PLT	14,080,608	0	0	0	6,024,510	0	0
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	0	0	0	15,930,703	0	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	E362PLT	124,204,880	0	0	0	53,142,139	0	0
27	RBP	- Substation related	E362PLT	118,051,566	0	0	0	50,509,390	0	0
28	RBP	Total Accounts E360-E361		293,570,614	0	0	0	125,606,741	0	0
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations - Energy Related - System		269,637,863	0	0	0	0	0	0
31	RBP	Switching Stations - Demand Related - System		68,805,545	0	0	0	68,805,545	0	0
32	RBP	H Class Substations - Energy Related - System		626,002,523	0	0	0	0	0	0
33	RBP	H Class Substations - Demand Related - System		600,972,238	0	0	0	600,972,238	0	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0
36	RBP	Total Account E362		1,565,418,169	0	0	0	669,777,783	0	0
37	RBP	E364 - Poles Towers & Fixtures								
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	8,114,160	0	0	0	0	0
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	1,812,825	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		80,822,343	0	0	0	0	0	0
42	RBP	Subtransmission lines - Demand Related - System		20,624,052	0	0	0	20,624,052	0	0
43	RBP	Primary Lines - Energy Related - Local		123,061,406	0	0	0	0	0	0
44	RBP	Primary Lines - Energy Related - System		123,061,406	0	0	0	0	0	0
45	RBP	Primary Lines - Demand Related - Local		118,140,880	0	0	118,140,880	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	RBP	Primary Lines - Demand Related - System		118,140,880	0	0	0	118,140,880	0	0
47	RBP	Secondary Lines - Energy Related - Local		227,674,404	0	0	0	0	0	0
48	RBP	Secondary Lines - Demand Related - Local		205,991,127	0	0	205,991,127	0	0	0
49	RBP	Total Account E364		1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0
50	RBP									
51	RBP									
52	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
53	RBP									
54	RBP	DISTRIBUTION PLANT CONTINUED								
55	RBP	E365 - OH Conductors and Devices								
56	RBP	Direct - BPL	DIR_BPL_02	2,226,625	2,226,625	0	0	0	0	0
57	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	6,436,532	0	0	0	0	0
58	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
59	RBP	Subtransmission lines - Energy Related - System		160,845,181	0	0	0	0	0	0
60	RBP	Subtransmission lines - Demand Related - System		41,044,089	0	0	0	41,044,089	0	0
61	RBP	Primary lines - Energy Related - Local		643,665,448	0	0	0	0	0	0
62	RBP	Primary lines - Energy Related - System		643,665,448	0	0	0	0	0	0
63	RBP	Primary lines - Demand Related - Local		617,928,923	0	0	617,928,923	0	0	0
64	RBP	Primary lines - Demand Related - System		617,928,923	0	0	0	617,928,923	0	0
65	RBP	Secondary lines -Energy Related - Local		64,282,796	0	0	0	0	0	0
66	RBP	Secondary lines -Demand Related - Local		58,160,625	0	0	58,160,625	0	0	0
67	RBP	Other	DISTPLT	0	0	0	0	0	0	0
68	RBP	Total Account E365		2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0
69	RBP									
70	RBP	E366 - Underground Conduit								
71	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
72	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
73	RBP	Underground Conduits	E367PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0
74	RBP	Not Used	not_used							
75	RBP	Total Account E366		512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0
76	RBP									
77	RBP	E367 - Underground Conductors & Devices								
78	RBP	Direct - BPL	DIR_BPL_02	2,325,498	2,325,498	0	0	0	0	0
79	RBP	Direct - PSAL	DIR_PSAL_02	868,520	868,520	0	0	0	0	0
80	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	186,813	205,472	929,335	724,480	0	0
81	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
82	RBP	367.1 - Conventional UG								
83	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	40,943,727	0	0	0	0	0	0
84	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	10,447,922	0	0	0	10,447,922	0	0
85	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	90,324,112	0	0	0	0	0	0
86	RBP	Primary lines - Energy Related - System	KWH_PRI_09	90,324,112	0	0	0	0	0	0
87	RBP	Primary lines - Demand Related - Local	CP_PRI_04	86,712,563	0	0	86,712,563	0	0	0
88	RBP	Primary lines - Demand Related - System	CP_PRI_05	86,712,563	0	0	0	86,712,563	0	0
89	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	283,098,081	0	0	0	0	0	0
90	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	256,136,359	0	0	256,136,359	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	RBP	367.2 - BUD								
92	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	381,867	0	0	0	0	0	0
93	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	97,444	0	0	0	97,444	0	0
94	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	114,385,571	0	0	0	0	0	0
95	RBP	Primary lines - Energy Related - System	KWH_PRI_09	114,385,571	0	0	0	0	0	0
96	RBP	Primary lines - Demand Related - Local	CP_PRI_04	109,811,942	0	0	109,811,942	0	0	0
97	RBP	Primary lines - Demand Related - System	CP_PRI_05	109,811,942	0	0	0	109,811,942	0	0
98	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	15,979,016	0	0	0	0	0	0
99	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	14,457,205	0	0	14,457,205	0	0	0
100	RBP	Other	E367PLT	0	0	0	0	0	0	0
101	RBP	Total Account E367		1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0
102	RBP									
103	RBP	E368 - Line Transformers								
104	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	835,637,581	0	0	0	0	0	0
105	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	756,053,050	0	0	756,053,050	0	0	0
106	RBP	Not Used	not_used	0	0	0	0	0	0	0
107	RBP	Total Account E368		1,591,690,631	0	0	756,053,050	0	0	0
108	RBP	E369 - Services								
109	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	0	535,269,333	0	0	0	0
110	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
111	RBP	Total Account E369		535,269,333	0	535,269,333	0	0	0	0
112	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0
113	RBP									
114	RBP	E370 - Meters		0	0	0	0	0	0	0
115	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
116	RBP	Customer Component	METERSMIN_07	76,316,914	0	0	0	0	0	76,316,914
117	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	122,177,671	0	0	122,177,671	0	0	0
118	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	166,926,857	0	0	0	0	0	0
119	RBP	Total Account E370		365,421,442	0	0	122,177,671	0	0	76,316,914
120	RBP									
121	RBP	E373 - Street Lighting & Signal Systems								
122	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	340,539,607	0	0	0	0	0
123	RBP	PSAL luminaires & poles	DIR_PSAL_02	122,261,652	122,261,652	0	0	0	0	0
124	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	36,225,893	1,700,598	1,870,457	8,459,940	6,595,096	0	0
125	RBP	Total Account E373		499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0
126	RBP									
127	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	932,488	0	30,447,221	13,034,833	0	0
128	RBP									
129	RBP	Other Distribution and Unallocated Plant								
130	RBP	Not Used	not_used	0	0	0	0	0	0	0
131	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
132	RBP									
133	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914
134	RBP									
135	RBP	GENERAL AND COMMON PLANT								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
136	RBP	E390-E398 GENERAL PLANT								
137	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
138	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
139	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0
140	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0
141	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
142	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
143	RBP	Total Accounts E390-E398		429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0
144	RBP									
145	RBP	C389-C399 COMMON PLANT								
146	RBP	Not Used	not_used	0	0	0	0	0	0	0
147	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
148	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0
149	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0
150	RBP	Customer Service Related	CUSTSVSX	92,605,476	0	0	3,365,638	0	71,953,745	17,286,093
151	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	1,583,834	1,742,030	7,879,075	6,142,271		
152	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
153	RBP	Unassigned	COMPLT	309,972	3,886	4,274	27,588	15,069	176,531	42,410
154	RBP	Not Used	not_used	0	0	0	0	0	0	0
155	RBP	Total Accounts C389-C399		126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503
156	RBP									
157	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503
158	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
159	RBP									
160	RBP	INTANGIBLE PLANT - E301-E303								
161	RBP	Customer Service Related	TOTPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380
162	RBP	Not Used	not_used	0	0	0	0	0	0	0
163	RBP	TOTAL INTANGIBLE PLANT		40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380
164	RBP									
165	RBP	C303 - INTANGIBLE PLANT								
166	RBP	- Customer Related - Measurement	MRCOST_07	606,400	0	0	0	0	0	606,400
167	RBP	- Demand Related - Measurement	NCP_MTR_07	606,400	0	0	0	0	0	606,400
168	RBP	Customer Service Related	CUSTSVSX	84,635,615	0	0	3,075,982	0	65,761,224	15,798,408
169	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
170	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
171	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
172	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307		
173	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	23,029	25,329	3,190,542	89,307	65,761,224	17,011,208
174	RBP									
175	RBP	TOTAL INTANGIBLE PLANT		126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589
176	RBP									
177	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006
178	RBP									
179	RBP									
180	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
181	RBP									
182	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	0	0	572,705	0	12,243,829	2,941,445
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	0	0	572,705	0	12,243,829	2,941,445
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	0	0	0	285,764	0	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	40,449,681	1,834,475	2,017,706	9,584,647	7,114,286	0	286,527
21	RBD	- Substation Related	E362PLT	36,319,499	0	0	0	15,539,614	0	0
22	RBD	Total Accounts E360-E361		77,437,073	1,834,475	2,017,706	9,584,647	22,939,663	0	286,527
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	0	0	0	119,497,984	0	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	1,932,962	0	63,114,300	27,020,014	0	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	1,850,198	0	144,393,035	140,737,441	0	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	610,171	37,084	84,473,035	37,502,653	0	0
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	1,211,370	73,622	167,703,909	74,453,837	0	0
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	198,944,531	0	0	0	0	0	0
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	179,997,433	0	0	179,997,433	0	0	0
38	RBD	E369 Services - Rsrv								
39	RBD	Services	E369PLT	240,814,772	0	240,814,772	0	0	0	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		240,814,772	0	240,814,772	0	0	0	0
42	RBD	E370 Meters - Rsrv								
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	136,921,647	0	0	45,779,382	0	0	28,595,579
45	RBD	Total Account E370 Rsrv		136,921,647	0	0	45,779,382	0	0	28,595,579

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0
50	RBD									
51	RBD									
52	RBD									
53	**RBD**	**DEPRECIATION RESERVE & AMORT CONTINUED**								
54	RBD									
55	RBD									
56	RBD									
57	RBD	Other Plant Unallocated - Reserve								
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
61	RBD									
62	RBD	Not Used	not_used	0	0	0	0	0	0	0
63	RBD	Not Used	not_used	0	0	0	0	0	0	0
64	RBD	Not Used	not_used	0	0	0	0	0	0	0
65	RBD									
66	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	118,149,623	243,388,992	697,062,102	423,723,484		28,882,106
67	RBD									
68	RBD	GENERAL AND COMMON PLANT RESERVE								
69	RBD	E390-E398 GENERAL PLANT - RESERVE								
70	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
71	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
72	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
73	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0
74	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
75	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
76	RBD	Total Accounts E390-E398 Reserve		156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0
77	RBD									
78	RBD	C389-C399 COMMON PLANT RESERVE								
79	RBD	Not Used	not_used	0	0	0	0	0	0	0
80	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
81	RBD	Meter Reading Related - Customer Related Measurement	MRCOST_07	0	0	0	0	0	0	0
82	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0
83	RBD	Customer Service Related	CUSTSVSX	46,782,308	0	0	1,700,248	0	36,349,495	8,732,565
84	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	900,197	990,111	4,478,199	3,491,059	0	0
85	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
86	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
87	RBD	Not Used	not_used	0	0	0	0	0	0	0
88	RBD	Total Accounts C389-C399 Reserve		65,958,182	900,197	990,111	6,178,447	3,491,059	36,349,495	8,732,565
89	RBD									
90	RBD	C303 - INTANGIBLE PLANT								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	RBD	- Customer Related - Measurement	MRCOST_07	311,743	0	0	0	0	0	311,743
92	RBD	- Demand Related - Measurement	NCP_MTR_07	311,743	0	0	0	0	0	311,743
93	RBD	Customer Service Related	CUSTSVSX	46,570,192	0	0	1,692,539	0	36,184,682	8,692,971
94	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
95	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
96	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
97	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307	0	0
98	RBD	Total Accounts C303-C390.4,E399		47,684,230	23,029	25,329	1,807,099	89,307	36,184,682	9,316,457
99	RBD									
100	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573
101	RBD									
102	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	925,712,100	51,229,033	15,988,807	199,291,015	148,298,198	56,489,000	37,720,924
7	RBO	Materials and Supplies	EXPENDITURES	227,211,892	12,573,937	3,924,381	48,915,088	36,399,129	13,864,972	9,258,432
8	RBO	Prepayments	EXPENDITURES	500,266	27,685	8,641	107,699	80,142	30,527	20,385
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		1,153,424,258	63,830,655	19,921,829	248,313,802	184,777,469	70,384,500	46,999,741
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,016,196,832	46,086,595	50,689,805	240,790,218	178,728,596		7,198,277
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	495,177	22,138	24,349	115,708	85,853	5,981	4,800
13	RBO	Capital Stimulas Adjust	DISTPLT							
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	286,198,206	13,210,949	10,645,918	66,261,863	52,413,918	1,835,596	2,094,949
15	RBO	CEF-EC Adjustment	ECPRO_07	670,378,464						670,378,464
16	RBO	CEF-EV Adjustment	TOTREV	43,223,143	1,922,767	1,277,190	8,496,378	6,899,941	2,795,918	3,764,670
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,169,916,080	125,073,103	82,559,090	563,977,968	422,905,778	75,021,994	730,440,902
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(63,735,780)	(2,837,691)	(1,886,245)	(12,528,067)	(10,173,104)	(4,124,283)	(5,557,527)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(27,893,945)	(84,606)		(6,602,796)	(6,435,633)		
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(100,491)	(110,528)	(525,234)	(389,713)	(27,149)	(21,787)
28	RBO	Cost of Removal	TOTPLT	15,629,066	698,727	768,517	3,652,040	2,709,737	188,774	151,489
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	312,066	14,405	11,608	72,251	57,151	2,002	2,284
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	294,443	237,274	1,476,833	1,168,192	40,911	46,692
33	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(1,820,476,207)	(80,842,456)	(88,917,143)	(422,280,957)	(313,515,432)	(33,317,895)	(19,595,504)
34	RBO	Total Deferred Income Taxes and Credits		(1,800,404,102)	(79,935,371)	(88,010,271)	(417,605,067)	(309,970,064)	(33,113,358)	(19,416,826)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,892,033,827)	(82,857,667)	(89,896,516)	(436,735,931)	(326,578,801)	(37,237,641)	(24,974,353)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	91,595	22,223	732,158	623,459	192,724	135,838
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	954,257	633,861	4,216,696	3,424,395	1,387,596	1,868,381
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	0	0	0	1,086,581	0	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	12,727	0	993,213	968,068	0	0
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	14,646	890	2,027,589	900,168	0	0
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	161,130	649	2,935	2,288		
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	METERPLT_07	5,865,310	0	0	0	0	0	5,865,310
22	E	- Excess portion	not_used	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07	0	0	0	0	0	0	0
24	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0
25	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	413,979	3,380	868,547	6,494,243	0	12,881,096
27	E	E589 Rents	DISTPLT	1,330,133	60,324	66,350	315,178	233,944	0	9,422
28	E	Total Distribution Operation		53,572,940	662,805	71,268	1,579,212	9,685,291	0	18,755,828
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	0	0	0	5,273,590	0	0
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	0	0	0	7,365,772	0	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	40,988	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	170,781	0	13,328,049	12,990,623	0	0
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	47,426	2,882	6,565,757	2,914,934	0	0
38	E	Not used	not_used	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	2,207,903	0	0	0	0	0	0
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	1,997,626	0	0	1,997,626	0	0	0
41	E	E596 Maint of Street Lighting & Signal Systems								
42	E	- BPL luminaires	DIR_BPL_02	8,123,869	8,123,869	0	0	0	0	0
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	340,052	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	3,594,664	0	0	0	0	0
45	E	E597 Maint of Meters								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	858,670	0	0	287,094	0	0	179,330
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	124,309	29	221,694	285,332	0	1,793
50	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
51	E									
52	E	Total Distribution Maintenance		124,436,319	12,560,300	2,911	22,400,220	28,830,251	0	181,123
53	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951
54	E									
55	E									
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951
57	E									
58	E									
59	E	CUSTOMER ACCOUNTS EXPENSES								
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
61	E	E902 Meter Reading								
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	9,323,486	0	0	0	0	0	9,323,486
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	9,323,486	0	0	0	0	0	9,323,486
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	-283,695	0	0	0	0	0	-283,695
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	-283,695	0	0	0	0	0	-283,695
70	E	E903 Customer Records and Collection								
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	275,332	0	0	275,332	0	0	0
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	275,332	0	0	275,332	0	0	0
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	266,527	0	0	0	0	0	266,527
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	266,527	0	0	0	0	0	266,527
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	40,496	0	0	0	0	40,496	0
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	40,496	0	0	0	0	40,496	0
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	3,872,512	0	0	0	0	3,872,512	0
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	3,872,512	0	0	0	0	3,872,512	0
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	531,469	0	0	531,469	0	0	0
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	531,469	0	0	531,469	0	0	0
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	33,170,904	0	0	0	0	33,170,904	0
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	33,170,904	0	0	0	0	33,170,904	0
85	E	Not used	not_used	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
88	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	0	0	1,613,601	0	74,167,825	18,612,636
89	E									
90	E									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	E	CUSTOMER SERVICE & INFO EXPENSES								
92	E	E907 & 908 - Cust Svs & Info								
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	2,356,739	0	0	0	0	2,356,739	0
95	E	- Utility work related	UTILWORK_04	847,228	0	0	847,228	0	0	0
96	E	- Sales	SALES_06	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	41,297	0	0	0	0	41,297	0
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info								
101	E	- Utility work related	UTILWORK_04	1,163,089	0	0	1,163,089	0	0	0
102	E	- Acct Maint related	ACCTMAINT_06	689,620	0	0	0	0	689,620	0
103	E	- Not used	not_used	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	220,028					220,028	
108	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
109	E									
110	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	0	0	2,010,317	0	3,307,684	0
111	E									
112	E	SALES EXPENSES								
113	E	E911-E916 Sales Expenses								
114	E	- Sales	SALES_06	0	0	0	0	0	0	0
115	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
116	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
117	E	- Utility work related	UTILWORK_04	40,922	0	0	40,922	0	0	0
118	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0
119	E	- Clause	not_used							
120	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	0	0	40,922	0	0	0
121	E									
122	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	13,223,105	74,179	27,644,272	38,515,543	77,475,509	37,549,587
123	E									
124	E	ADMINISTRATIVE & GENERAL EXPENSE								
125	E	E920 A&G Salaries	REVREQ	5,694,688	253,543	168,533	1,119,362	908,950	368,498	496,556
126	E	E921 Office Supplies & Exp	REVREQ	622,444	27,713	18,421	122,349	99,351	40,278	54,275
127	E	E923 Outside Services Employed	DISTPLT	68,020,983	3,084,890	3,393,014	16,117,731	11,963,524	0	481,830
128	E	E924 Property Insurance	TOTPLT	1,802,573	80,587	88,637	421,207	312,527	21,772	17,472
129	E	E925 Injuries & Damages	LABOR	14,161,029	678,137	2,974	1,799,423	1,163,501	4,414,263	3,535,479
130	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-3,733,637	-16,373	-9,907,129	-6,405,917	-24,303,713	-19,465,372
131	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	669,728	445,175	2,956,767	2,400,969	973,378	1,311,640
132	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	-913	-676,371	-542,508	-127,369	-61,591
133	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	0	0	2,277,517	0	0	0
134	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	132,998	146,282	694,879	515,780	0	20,773
135	E	E931 Rents	DISTPLT	4,471,819	202,806	223,063	1,059,608	786,503	0	31,676

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
136	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
137	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
138	E	Not Used	not_used	0	0	0	0	0	0	0
139	E	TOTAL A&G EXPENSE		33,695,393	1,396,765	4,468,813	15,985,344	11,202,679	-18,612,894	-13,577,262
140	E									
141	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	11,690,355	12,858,009	61,079,002	45,336,411	0	1,825,920
7	DE	General Plant	GENPLT	19,786,964	928,885	1,021,663	4,620,908	3,602,311	0	0
8	DE	Common Plant	COMPLT	9,215,747	115,527	127,067	820,208	448,028	5,248,426	1,260,876
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	285,087	313,561	1,418,216	1,105,595	0	0
15	DE	Meter Reading	MRCOST_07	492,670	0	0	0	0	0	492,670
16	DE	Customer Service related	CUSTSVSX	14,826,022	0	0	538,834	0	11,519,706	2,767,482
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-12,316	-13,546	-64,373	-47,763	-3,327	-2,670
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-539,968	-2,368	-1,432,793	-926,439	-3,514,861	-2,815,129
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	21,861,618	0	0	0	0	0	21,861,618
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	4,303,381	198,645	160,076	996,338	788,115	27,601	31,500
14	EO	BGS Administrative Expense Adjustment	A_GEXP	-220,495	-10,131	-8,857	-51,129	-34,771	-11,237	-11,627
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-1,199,974	-57,464	-252	-152,479	-98,592	-374,055	-299,589
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,361,661	352,532	1,546	935,437	604,850	2,294,770	1,837,931
22	EO	Payroll Taxes (Rate Year)	LABOR	506,132	24,237	106	64,313	41,585	157,771	126,362
23	EO	Interest Syncronization	TOTPLTNET	-1,029,929	-47,542	-38,311	-238,454	-188,620	-6,606	-7,539
24	EO	- add'l tax effects on rev req	TOTPLTNET	-402,717	-18,589	-14,980	-93,239	-73,753	-2,583	-2,948
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	20,935,341	1,002,543	4,396	2,660,226	1,720,094	6,525,946	5,226,772
26	EO	COLI Interest Expense Recovery	LABOR	2,119,856	101,515	445	269,367	174,172	660,800	529,249
27	EO	- add'l tax effects on rev req	LABOR	828,893	39,694	174	105,326	68,104	258,382	206,944
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-41,607	-1,860	-2,046	-9,722	-7,214	-503	-403
32	EO	- add'l tax effects on rev req	TOTPLT	-16,269	-727	-800	-3,802	-2,821	-197	-158
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	616,778	27,574	30,328	144,122	106,936	7,450	5,978
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-772,360	-849,505	-4,036,895	-2,995,292	-208,667	-167,453
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	482,666	21,579	23,734	112,785	83,684	5,830	4,678
38	EO	Rate Case Expenses	TOTPLT	188,766	8,439	9,282	44,109	32,728	2,280	1,830
39	EO	Depreciation Rate Change	DEPREXP	44,543,977	1,978,078	2,175,652	10,332,501	7,671,193	815,233	479,469
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		72,010,790	2,293,879	1,475,076	9,581,640	6,916,195	6,634,026	27,004,816
49	EO	TOTAL OPERATING REVENUES	CALCULATED	1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675
50	EO	LESS:								
51	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325
52	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948
53	EO	OTHER OPERATING EXPENSES	CALCULATED	72,010,790	2,293,879	1,475,076	9,581,640	6,916,195	6,634,026	27,004,816
54	EO	NET OPERATING INCOME BEFORE TAXES		1,196,353,939	54,052,811	35,449,238	249,433,135	194,262,476	39,860,850	107,116,586
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(6,350,955)	(5,117,857)	(31,854,346)	(25,197,165)	(882,434)	(1,007,114)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,333,939,214	60,403,767	40,567,095	281,287,480	219,459,641	40,743,284	108,123,700
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	0	0	-17,563	0	0	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	17,563	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	TI	**DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**TAX ADJUSTMENTS - FEDERAL**								
4	TI	Additional Expenses on Rental Property	TOTPLT	-108,083	-4,832	-5,315	-25,256	-18,739	-1,305	-1,048
5	TI	Additional Rental Income - NJ Properties	TOTPLT	16,349	731	804	3,820	2,835	197	158
6	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
7	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
8	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	526	579	2,751	2,041	142	114
9	TI	CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	CEF- EC AMI	TOTPLT	-20,866,765	-932,889	-1,026,067	-4,875,932	-3,617,839	-252,036	-202,257
11	TI	CEF- EV Deferral	TOTPLT	-1,855,840	-82,969	-91,256	-433,654	-321,762	-22,416	-17,988
12	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	Company Owned Life Insurance - Book	LABOR	-1,117,127	-53,497	-235	-141,952	-91,786	-348,230	-278,905
17	TI	Company Owned Life Insurance - Tax	LABOR	-58,279	-2,791	-12	-7,405	-4,788	-18,167	-14,550
18	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	Current SHARE -- FT	DEPREXP	-11,513,122	-511,267	-562,333	-2,670,605	-1,982,746	-210,710	-123,927
20	TI	Customer Advances	TOTPLTNET	4,645,423	214,433	172,799	1,075,529	850,756	29,794	34,004
21	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	6,684,538	308,559	248,650	1,547,634	1,224,197	42,873	48,930
22	TI	Deduction for Retention Payments (c)	LABOR	-5,352	-256	-1	-680	-440	-1,668	-1,336
23	TI	Deferred Employer ER FICA	LABOR	-7,086,760	-339,368	-1,488	-900,505	-582,264	-2,209,078	-1,769,299
24	TI	Diesel Fuel Tax Credit	TOTPLT	82	4	4	19	14	1	1
25	TI	Entertainment (100%)	LABOR	38,419	1,840	8	4,882	3,157	11,976	9,592
26	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
28	TI	Injuries & Damages - FT	TOTPLT	1,298,774	58,064	63,864	303,484	225,179	15,687	12,589
29	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	Plant Related	DEPREXP	-33,454,683	-1,485,633	-1,634,020	-7,760,209	-5,761,437	-612,279	-360,104
31	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0
32	TI	Qualified Transportation Fringe	LABOR	162,269	7,771	34	20,619	13,332	50,582	40,512
33	TI	R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	R&D Expenditure	TOTPLT	-5,622	-251	-276	-1,314	-975	-68	-54
35	TI	Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	RE - Lease Liability	TOTPLT	-236,259	-10,562	-11,617	-55,207	-40,962	-2,854	-2,290
37	TI	RE - ROU Lease Asset	TOTPLT	319,172	14,269	15,694	74,581	55,337	3,855	3,094
38	TI	Reversal of Book Income from Partnerships	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409
39	TI	Severance Pay (nc)	LABOR	154,681	7,407	32	19,655	12,709	48,217	38,618
40	TI	State NOL CF (c)	DEPREXP	17,908,279	795,259	874,690	4,154,037	3,084,095	327,753	192,764
41	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-20,606	-22,664	-107,700	-79,911	-5,567	-4,467
42	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	Unrealized G/L on Equity Securities	TOTPLT	125,367	5,605	6,165	29,295	21,736	1,514	1,215
44	TI	Stock Based Compensation	TOTPLTNET	-328,125	-15,146	-12,206	-75,969	-60,092	-2,105	-2,402
45	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	Partnership income/loss per K-1	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409
51	TI	Meals & entertainment	LABOR	-417,376	-19,987	-88	-53,035	-34,293	-130,104	-104,203
52	TI	Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-47,653	-38,401	-239,014	-189,063	-6,621	-7,557
54	TI	Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0	0
56	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,841,683	88,194	387	234,020	151,317	574,088	459,799
57	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
59	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
60	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
61	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
62	TI	AFUDC / IDC	TOTPLT	-1,076,666	-48,134	-52,942	-251,584	-186,670	-13,004	-10,436
63	TI	Capitalized interest-Section 263A	TOTPLT	3,363,340	150,365	165,383	785,911	583,129	40,624	32,600
64	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0
65	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0
66	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
67	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
68	TI	Deferred Comp - officers	LABOR	11,058	530	2	1,405	909	3,447	2,761
69	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
70	TI	Accrued vacation pay adjustment	LABOR	-344,695	-16,507	-72	-43,800	-28,321	-107,448	-86,057
71	TI	3rd Party Claims	TOTPLT	87,346	3,905	4,295	20,410	15,144	1,055	847
72	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0
73	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
74	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
75	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0
76	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
77	TI	Contribution in Aid of Construct	TOTPLTNET	905,779	41,811	33,693	209,710	165,883	5,809	6,630
78	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
79	TI	Pension Accrual Adjustment	LABOR	-3,671,962	-175,841	-771	-466,591	-301,697	-1,144,621	-916,752
80	TI	Unallowable OPEB Amortization	LABOR	-105,080,197	-5,032,036	-22,067	-13,352,404	-8,633,621	-32,755,504	-26,234,595
81	TI	Deferred Return on CIP II	TOTPLT	66,348	2,966	3,263	15,504	11,503	801	643
82	TI	Deferred Depreciation on CIP II	TOTPLT	52,458	2,345	2,580	12,258	9,095	634	508
83	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
84	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	91,151	4,208	3,391	21,104	16,693	585	667
85	TI	Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
86	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	1,120,547	51,725	41,682	259,434	205,215	7,187	8,202
87	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-1,045,327	-48,252	-38,884	-242,019	-191,440	-6,704	-7,652
88	TI									
89	TI									
90	TI									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
92	TI	**TAX ADJUSTMENTS - FEDERAL CONTINUED**								
93	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0
94	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
95	TI	Penalties	not_used	0	0	0	0	0	0	0
96	TI	Restricted Stock - Permanent	TOTPLTNET	-82,615	-3,814	-3,073	-19,128	-15,130	-530	-605
97	TI	Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
98	TI	Legal Reserves (c & nc)	TOTPLTNET	401,853	18,550	14,948	93,039	73,595	2,577	2,942
99	TI	Material Supplies & Reserves	TOTPLT	107,143	4,790	5,268	25,036	18,576	1,294	1,039
100	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0	0
101	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	62,834	2,900	2,337	14,548	11,507	403	460
102	TI	Real Estate Taxes	TOTPLTNET	1,046,714	48,316	38,935	242,340	191,694	6,713	7,662
103	TI	Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0
104	TI	**Miscellaneous**	TOTPLT							
105	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-7,017,220	-1,824,302	-22,552,940	-15,194,328	-36,673,211	-29,240,133
106	TI									
107	TI	**TAX ADJUSTMENTS - STATE**								
108	TI	TEFA	TEFA_04	0	0	0	0	0	0	0
109	TI	Federal Depreciation Reversal	DEPREXP	72,042,765	3,199,226	3,518,770	16,711,170	12,406,929	1,318,508	775,464
110	TI	State Tax Depreciation	DEPREXP	36,681,624	1,628,932	1,791,633	8,508,736	6,317,169	671,338	394,839
111	TI	not used	not_used	0	0	0	0	0	0	0
112	TI	**TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	4,828,158	5,310,403	25,219,906	18,724,097	1,989,846	1,170,303
113	TI									
114	TI	**TAXABLE NET INCOME - STATE**		1,293,338,867	58,214,705	44,053,196	283,954,447	222,989,410	6,059,920	80,053,871
115	TI	State Tax Liability		116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848
116	TI	Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
117	TI	**TOTAL STATE INCOME TAX LIABILITY**		116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848
118	TI									
119	TI	**TAXABLE NET INCOME - FEDERAL**		1,068,213,981	48,147,223	34,778,006	233,178,640	184,196,266	3,524,681	71,678,719
120	TI	Federal Tax Liability		224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531
121	TI	not used	not_used	0	0	0	0	0	0	0
122	TI	not used	not_used	0	0	0	0	0	0	0
123	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531
124	TI									
125	TI	**TOTAL INCOME TAX EXPENSE**		340,725,434	15,350,240	11,268,169	74,523,415	58,750,263	1,285,576	22,257,379
126	TI									
127	TI									
128	TI									
129	TI									
130	TI	**TAX RATES**								
131	TI	FEDERAL TAX RATE - CURRENT		21.000%						
132	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%						
133	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000						
134	TI	EFFECTIVE TAX RATE		28.110%						
135	TI	COMPOSITE RATE		28.110%						

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
136	TI	1 - EFFECTIVE TAX RATE		71.89000%						
137	TI									
138	TI									
139	TI									
140	TI									
141	TI									
142	TI									
143	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
144	TI	Additional Rental Income - NJ Properties	TOTPLT	-16,349	-731	-804	-3,820	-2,835	-197	-158
145	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
146	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
147	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	53,745	2,403	2,643	12,559	9,318	649	521
148	TI	Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-51,725	-41,682	-259,434	-205,215	-7,187	-8,202
149	TI	CECL Reserve	not_used	0	0	0	0	0	0	0
150	TI	CEF- EC AMI	TOTPLT	20,866,765	932,889	1,026,067	4,875,932	3,617,839	252,036	202,257
151	TI	CEF- EV Deferral	TOTPLT	1,855,840	82,969	91,256	433,654	321,762	22,416	17,988
152	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
153	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
154	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
155	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
156	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0
157	TI	Current SHARE -- FT	DEPREXP	2,912,070	129,317	142,234	675,489	501,506	53,296	31,345
158	TI	Customer Advances	TOTPLTNET	-4,645,423	-214,433	-172,799	-1,075,529	-850,756	-29,794	-34,004
159	TI	Deduction for Retention Payments (c)	LABOR	5,352	256	1	680	440	1,668	1,336
160	TI	Deferred Employer ER FICA	LABOR	7,086,760	339,368	1,488	900,505	582,264	2,209,078	1,769,299
161	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
162	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0
163	TI	Injuries & Damages - FT	TOTPLT	-328,505	-14,686	-16,153	-76,762	-56,956	-3,968	-3,184
164	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0
165	TI	Medicare Subsidy	not_used	0	0	0	0	0	0	0
166	TI	Partnership Income/Loss (nc)	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409
167	TI	Plant Related	DEPREXP	37,305,084	1,656,619	1,822,084	8,653,355	6,424,538	682,748	401,550
168	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0
169	TI	R & D Credits CF	TOTPLT	-15,263	-682	-751	-3,566	-2,646	-184	-148
170	TI	RE - Lease Liability	TOTPLT	236,259	10,562	11,617	55,207	40,962	2,854	2,290
171	TI	RE - ROU Lease Asset	TOTPLT	-319,172	-14,269	-15,694	-74,581	-55,337	-3,855	-3,094
172	TI	Real Estate Taxes (nc)	TOTPLT	-1,046,714	-46,795	-51,469	-244,585	-181,477	-12,643	-10,146
173	TI	Reversal of Book Income from Partnerships	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409
174	TI	Severance Pay (nc)	LABOR	-154,681	-7,407	-32	-19,655	-12,709	-48,217	-38,618
175	TI	State NOL CF (c)	DEPREXP	-17,908,279	-795,259	-874,690	-4,154,037	-3,084,095	-327,753	-192,764
176	TI	Unrealized G/L on Equity Securities	TOTPLT	-125,367	-5,605	-6,165	-29,295	-21,736	-1,514	-1,215
177	TI	**E410 + E411- PROVISION FOR DEFERRED INCOME TAX**								
178	TI	Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
179	TI	Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
180	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
181	TI	Amortization of Power Gain	not_used	0	0	0	0	0	0	0
182	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
183	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
184	TI	AFUDC / IDC	TOTPLT	1,076,666	48,134	52,942	251,584	186,670	13,004	10,436
185	TI	Capitalized interest-Section 263A	TOTPLT	-3,363,340	-150,365	-165,383	-785,911	-583,129	-40,624	-32,600
186	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0
187	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0
188	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
189	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
190	TI	Deferred Comp - officers	LABOR	-11,058	-530	-2	-1,405	-909	-3,447	-2,761
191	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
192	TI	Accrued vacation pay adjustment	LABOR	344,695	16,507	72	43,800	28,321	107,448	86,057
193	TI	3rd Party Claims	TOTPLT	-87,346	-3,905	-4,295	-20,410	-15,144	-1,055	-847
194	TI	Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
195	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0
196	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
197	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
198	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0
199	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
200	TI	Contribution in Aid of Construct	TOTPLTNET	-905,779	-41,811	-33,693	-209,710	-165,883	-5,809	-6,630
201	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
202	TI	Pension Accrual Adjustment	LABOR	3,671,962	175,841	771	466,591	301,697	1,144,621	916,752
203	TI	Unallowable OPEB Amortization	LABOR	105,080,197	5,032,036	22,067	13,352,404	8,633,621	32,755,504	26,234,595
204	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
205	TI	Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
206	TI	Rabbi Trust Unrealized Losses	LABOR	0	0	0	0	0	0	0
207	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
208	TI	Additional Real Estate Taxes	TOTPLT	108,083	4,832	5,315	25,256	18,739	1,305	1,048
209	TI	PIP Adjustment	LABOR	1,045,327	50,058	220	132,828	85,886	325,848	260,979
210	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
211	TI	Misc	TOTPLT	0	0	0	0	0	0	0
212	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
213	TI	Deferred Return on CIP II	TOTPLT	-66,348	-2,966	-3,263	-15,504	-11,503	-801	-643
214	TI	Deferred Depreciation on CIP II	TOTPLT	-52,458	-2,345	-2,580	-12,258	-9,095	-634	-508
215	TI	Customer Connections Fees	CUSTACCTS	-6,684,538	0	0	-114,268	0	-5,252,212	-1,318,058
216	TI	Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
217	TI	Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
218	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-91,151	-4,208	-3,391	-21,104	-16,693	-585	-667
219	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	0	0	0	0	0	0	0
220	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0
221	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0
222	TI	Audit Adjustment	not_used	0	0	0	0	0	0	0
223	TI	Stock Based Compensation	TOTPLTNET	328,125	15,146	12,206	75,969	60,092	2,105	2,402
224	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
225	TI	Legal Reserves (nc)	TOTPLTNET	-401,853	-18,550	-14,948	-93,039	-73,595	-2,577	-2,942

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
226	TI									
227	TI									
228	TI	**DEVELOPMENT OF OPERATING INCOME ADJ CONTINUE**								
229	TI	**E410 + E411- PROVISION FOR DEFER INC TAX CONTINUE**								
230	TI	Material Supplies & Reserves	TOTPLTNET	-107,143	-4,946	-3,985	-24,806	-19,622	-687	-784
231	TI	Medicare Subsidy	TOTPLTNET							
232	TI	**TOTAL DEFERRED INCOME TAX**		144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881
233	TI									
234	TI	**TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
235	TI	**TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
236	TI	**TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
237	TI									
238	TI	**OPERATING INCOME ADJUSTED**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	280,636	663	40	91,778	40,746	0	0
10	LR	583-Overhead Lines	E367PLT	941,919	2,225	135	308,041	136,758	0	0
11	LR	584-Underground Lines	E367PLT	4,591,058	10,845	659	1,501,438	666,578	0	0
12	LR	586-Metering	MTROMMIN_07	4,311,826	0	0	0	0	0	4,311,826
13	LR	587-Customer Installations	MTROMMIN_07	17,308,754	0	0	0	0	0	17,308,754
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	186,473	1,522	391,230	2,925,275	0	5,802,178
15	LR	Total Operation		43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	0	0	0	1,095,258	0	0
19	LR	592-Station Equipment	E362PLT	8,699,368	0	0	0	3,722,100	0	0
20	LR	593-Overhead Lines	E365PLT	11,294,340	34,257	0	2,673,491	2,605,807	0	0
21	LR	594-Underground Lines	E367PLT	11,333,758	26,773	1,627	3,706,538	1,645,555	0	0
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	0	0	2,457,581	0	0	0
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	7,299,789	29,395	132,951	103,644	0	0
24	LR	597-Meters	MTROMMIN_07	700,642	0	0	0	0	0	700,642
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	53,426	12	95,281	122,632	0	770
26	LR	Total Maintenance		45,417,214	7,414,246	31,034	9,065,842	9,294,996		701,413
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	7,614,452	33,391	11,358,327	13,064,353	0	28,124,171
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	0	0	1,003,385	0	46,119,752	11,573,889
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	0	0	2,094,208	0	3,445,715	0
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP	0	0	0	0	0	0	0
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	5,748,870	0	0	5,748,870	0	0	0
33	LR	**Employee Pension/Benefits Acct E926**	LABOR	0	0	0	0	0	0	0
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**								
2	CA									
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
5	CA									
6	CA	**TRANSMISSION PLANT**								
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
16	CA									
17	CA	**DISTRIBUTION PLANT**								
18	CA	E360 Land and Land Rights	E360PLT	3,481,598	0	0	0	1,489,632	0	0
19	CA	E361 Structures and Improvements	E361PLT	1,433,350	0	0	0	613,271	0	0
20	CA	E362 Station Equipment	E362PLT	72,557,752	0	0	0	31,044,465	0	0
21	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	835,763	0	27,289,006	11,682,762	0	0
22	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	712,839	0	55,631,373	54,222,955	0	0
23	CA	E366 Underground Conduits	E367PLT	3,221,386	7,610	462	1,053,507	467,715	0	0
24	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	77,501	4,710	10,729,288	4,763,375	0	0
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	48,751,051	0	0	0	0	0	0
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	44,108,093	0	0	44,108,093	0	0	0
27	CA	E369 Services	E369PLT	11,962,969	0	11,962,969	0	0	0	0
28	CA	E370 Meters	METERPLT	73,420,491	0	0	24,547,943	0	0	15,333,598
29	CA	E373 Street Lighting	E373PLT	39,887,684	37,128,046	149,507	676,211	527,152	0	0
30	CA	E374 Asset Retirement Obligations	TOTPLT							
31	CA	TOTAL DISTRIBUTION PLANT		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598
32	CA									
33	CA	**TOTAL CAPITAL ADDITIONS**		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	0	0	2,318,149	0	0	0
7	AF									
8	AF									
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	3,519,017	0	0	0	3,519,017	0	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,928,659	0	0	0	8,928,659	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	21,256,013	0	0	21,256,013	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,856,464	0	0	19,856,464	0	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	0	0	20,498,179	0	0	0
14	AF									
15	AF									
16	AF	CP @ secondary lines - local	CP_SEC_04	8,231,675	0	0	8,231,675	0	0	0
17	AF	CP @ primary lines - local	CP_PRI_04	8,928,659	0	0	8,928,659	0	0	0
18	AF	NCP @ meter - local	NCP_MTR_04	10,800,203	0	0	10,800,203	0	0	0
19	AF	NCP @ meter - measurement	NCP_MTR_07	10,800,203	0	0	0	0	0	10,800,203
20	AF	NCP @ meter - cust svs	NCP_MTR_06	10,800,203	0	0	0	0	10,800,203	0
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	10,698,184	0	0	0	0	0	10,698,184
22	AF									
23	AF	**BILLING DETERMINANTS**								
24	AF									
25	AF	Number of Customers		2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219
26	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119
27	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
28	AF									
29	AF									
30	AF	**ALLOCATION FACTORS PART B**								
31	AF									
32	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	0	0	40,816,033,564	0	0	0
33	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	0	0	21,338,981,079	0	0	0
34	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	12,282,908,123	0	0	0	0	0	0
35	AF	Delivery kWh @ primary - System E	KWH_PRI_09	36,303,573,183	0	0	0	0	0	0
36	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	36,303,573,183	0	0	0	0	0	0
37	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	32,329,765,823	0	0	0	0	0	0
38	AF	Delivery kWh @ meter - measurement	KWHMETER_07	40,781,263,034	0	0	0	0	0	40,781,263,034
39	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	40,781,263,034	0	0	0	0	40,781,263,034	0
40	AF									
41	AF									
42	AF	**ALLOCATION FACTORS PART C**								
43	AF									
44	AF	Avg Customer Bills - measurement	CUSTAVG_07	2,335,622	0	0	0	0	0	2,335,622
45	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	124,473,055	0	0	124,473,055	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	124,473,055	0	0	0	0	0	0
47	AF									
48	AF	Meter O&M - measurement	METERPLT_07	456,573,728	0	0	0	0	0	456,573,728
49	AF									
50	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	124,473,055	0	0	0	0	0	124,473,055
51	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
52	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
53	AF									
54	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
55	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	0	0	112	0	0	0
56	AF	E587 Customer Installation Expenses System	CUSINT_05	112	0	0	0	112	0	0
57	AF	Draft EC Proforma	ECPRO_07	434,841,736	0	0	0	0	0	434,841,736
58	AF	Expense Reclassification-local	ADJEXP_04	-17,563	0	0	-17,563	0	0	0
59	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	17,563	0	0	0
60	AF	E369 minimum Service investment- access	SERVICESMIN_03	360,747,418	0	360,747,418	0	0	0	0
61	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	709,786,184	0	0	709,786,184	0	0	0
62	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	0	0	2,348,219	0	0	0
63	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	0	0	0	0	2,348,219	0
64	AF	E370 minimum meter investment - measurement	METERSMIN_07	191,661,323	0	0	0	0	0	191,661,323
65	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	0	0	559,887,636	0	0	0
66	AF	Billing Function costs - cust svs	BILLING_06	130,951	0	0	0	0	130,951	0
67	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	0	0	0	0	80,564,013	0
68	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	0	0	0	0	0	20,538,511
69	AF	Sales	SALES_06	0	0	0	0	0	0	0
70	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	0	0	3,334,747	0	0	0
71	AF									
72	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
73	AF									
74	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
75	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
76	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	1	0	0	0	0	0
77	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	1	0	0	0	0	0
78	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	1	0	0	0	0	0
79	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	1	0	0	0	0
80	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
81	AF									
82	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	1	0	0	0	1	0	0
83	AF									
84	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	1	0	0	0
85	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	0	0	0	0	0	6,387,137
86	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
87	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
88	AF	E370 excess meter investment - dummy	METERSEXC_08	5,064	0	0	0	0	0	0
89	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
90	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
92	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
93	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
94	AF									
95	AF									
96	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
97	AF									
98	AF									
99	AF	**Plant Related**								
100	AF	Distribution Plant Total	DISTPLT	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914
101	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	488,615,049	537,418,784	2,430,706,197	1,894,899,857	0	0
102	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	0	0	0	21,955,213	0	0
103	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	0	0	0	103,651,528	0	0
104	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	0	0	0	669,777,783	0	0
105	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0
106	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0
107	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0
108	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0
109	AF	Acct E369 Services	E369PLT	535,269,333	0	535,269,333	0	0	0	0
110	AF	Acct E370 Meters	METERPLT	365,421,442	0	0	122,177,671	0	0	76,316,914
111	AF									
112	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	0	0	122,177,671	0	0	76,316,914
113	AF	Acct E373 - Streetlights	E373PLT	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0
114	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000			0.2110	0.7890		
115	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000			0.5000	0.5000		
116	AF									
117	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380
118	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0
119	AF	E391-E398 General Plant	GENPLT	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0
120	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
121	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
122	AF									
123	AF	Common Plant	COMPLT	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503
124	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503
125	AF									
126	AF	Total Plant	TOTPLT	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006
127	AF									
128	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573
129	AF	Total Net Plant	TOTPLTNET	8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433
130	AF									
131	AF									
132	AF	**Revenue Related**								
133	AF	Total Operating Revenue	TOTREV	1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675
134	AF									
135	AF	**Expense Related**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
136	AF	Distr Oper Exp	DISTEXPO	52,242,807	602,481	4,919	1,264,034	9,451,348	0	18,746,406
137	AF	Distr Maint Exp	DISTEXPM	123,204,777	12,435,991	2,882	22,178,526	28,544,919	0	179,330
138	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	0	0	2,010,317	0	3,307,684	0
139	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636
140	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	0	0	3,623,918	0	77,475,509	18,612,636
141	AF	Sales Expense	SALESEXP	40,922	0	0	40,922	0	0	0
142	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325
143	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	5,130,402	4,485,186	25,892,473	17,608,596	5,690,820	5,888,111
144	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636
145	AF	O&M + Capital Additions	EXPENDITURES	964,609,657	53,381,629	16,660,642	207,665,037	154,529,550	58,862,615	39,305,922
146	AF									
147	AF	Depreciation Expense (total)	DEPREXP	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796
148	AF									
149	AF	NJ State Income Tax (CBT)	STATEINCTAX	116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848
150	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	1,034,603	49,579	-308	130,323	84,027	325,719	260,875
151	AF									
152	AF	**Labor Expense Related**								
153	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758
154	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	7,414,246	31,034	9,065,842	9,294,996	0	701,413
155	AF	Total Labor	LABOR	159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060
156	AF									
157	AF	**REVENUES AND BILLING DETERMINANTS**								
158	AF									
159	AF	Base Rate Sales Revenue	SALESREV	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
160	AF									
161	AF	Residential Service	REVRS	817,837,432	0	86,433	180,063,110	139,066,006	70,757,324	127,086,199
162	AF	Residential Heating Service	REVRHS	4,371,623	0	544,133	585,845	447,756	342,780	441,165
163	AF	Residential Load Management Service	REVRLM	23,721,865	0	14,754,404	1,939,332	1,528,767	583,211	739,733
164	AF	Water Heating Service	REVWH	34,174,203	0	34,030,901	5,578	0	12,139	113,297
165	AF	Water Heating Storage Service	REVWHS	146,591	0	144,405	83	0	186	1,767
166	AF	Building Heating Service	REVHS	701,978	0	0	129,028	99,066	143,951	75,955
167	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
168	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
169	AF									
170	AF	Body Police Lighting Service	REVBLP	66,086,163	59,591,770	0	28,723	0	512,565	207
171	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	730,955	386,296	0	908	0	21,962	11
172	AF	Private Street and Area Lighting Service	REVPAL	26,795,398	22,962,497	0	22,568	0	932,125	100
173	AF	General Power and Lighting Service	REVGLP	384,902,021	0	5,443,311	98,013,689	75,139,161	22,903,156	23,638,990
174	AF	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	102,952	76,299,397	61,198,678	14,368,111	6,947,861
175	AF	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	24,942	8,841,568	15,660,204	3,074,816	1,173,602
176	AF	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	43	184,854	4,201,745	4,695,018	1,548,489
177	AF	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	58,023	0	2,197,961	669,083
178	AF	HEP	REVHEP	0	0	0	0	0	0	0
179	AF									
180	AF									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
181	AF	Total Rev Req @ desired ROR	REVREQ	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
182	AF									
183	AF									
184	AF	**PRESENT REVENUES FROM SALES INPUT**								
185	AF									
186	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
187	AF	Sales of Electricity Revenues - Rates		1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745
188	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
189	AF									
190	AF	**RATE OF RETURN**								
191	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
7	AP									
8	AP									
9	AP	CP @ secondary lines - local	CP_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
11	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
15	AP									
16	AP	CP @ primary lines - local	CP_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
17	AP	NCP @ meter - local	NCP_MTR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
18	AP	NCP @ meter - measurement	NCP_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
19	AP	NCP @ meter - cust svs	NCP_MTR_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
20	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
21	AP	**BILLING DETERMINANTS**								
22	AP									
23	AP	Number of Customers								
24	AP	Delivered kWh @ Meter - annual (w/n net)								
25	AP	Delivered Kw @ Meter - annual								
26	AP									
27	AP	**ALLOCATION FACTORS PART B**								
28	AP									
29	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
30	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
37	AP									
38	AP									
39	AP	**ALLOCATION FACTORS PART C**								
40	AP									
41	AP	Draft EC Proforma	ECPRO_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
42	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
43	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
44	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
45	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
47	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
48	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
49	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
50	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
51	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
52	AP	Avg Customer Bills - measurement	CUSTAVG_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
53	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
54	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
55	AP									
56	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
58	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
59	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
60	AP									
61	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP									
63	AP									
64	AP									
65	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
66	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
67	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
70	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
71	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
72	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
73	AP									
74	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
75	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
76	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
78	AP	Meter O&M - measurement	METERPLT_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
79	AP									
80	AP	E370 excess meter investment - dummy	METERSEXC_08	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
86	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
87	AP									
88	AP									
89	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
90	AP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
91	AP	**Plant Related**								
92	AP	Distribution Plant Total	DISTPLT	1.000000	0.045352	0.049882	0.236952	0.175880	0.000000	0.007084
93	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000
94	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000
95	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000
96	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000
97	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.009662	0.000000	0.315474	0.135058	0.000000	0.000000
98	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.003033	0.000000	0.236711	0.230718	0.000000	0.000000
99	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000
100	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000
101	AP	Acct E369 Services	E369PLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
102	AP	Acct E370 Meters	METERPLT	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846
103	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846
104	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.930815	0.003748	0.016953	0.013216	0.000000	0.000000
105	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.000000	0.000000	0.211000	0.789000	0.000000	0.000000
106	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.000000	0.000000	0.500000	0.500000	0.000000	0.000000
107	AP									
108	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693
109	AP									
110	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
111	AP	E391-E398 General Plant	GENPLT	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000
112	AP	Common Plant	COMPLT	1.000000	0.012536	0.013788	0.089001	0.048615	0.569506	0.136818
113	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.039110	0.043016	0.200623	0.151671	0.129675	0.031153
114	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
115	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
116	AP									
117	AP	Total Plant	TOTPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693
118	AP									
119	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.040788	0.081463	0.239455	0.147058	0.027354	0.016091
120	AP	Total Net Plant	TOTPLTNET	1.000000	0.046160	0.037198	0.231524	0.183139	0.006414	0.007320
121	AP									
122	AP									
123	AP	**Revenue Related**								
124	AP	Total Operating Revenue	TOTREV	1.000000	0.044485	0.029549	0.196570	0.159635	0.064686	0.087098
125	AP									
126	AP	**Expense Related**								
127	AP	Distr Oper Exp	DISTEXPO	1.000000	0.011532	0.000094	0.024195	0.180912	0.000000	0.358832
128	AP	Distr Maint Exp	DISTEXPM	1.000000	0.100938	0.000023	0.180014	0.231687	0.000000	0.001456
129	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.000000	0.378021	0.000000	0.621979	0.000000
130	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180
131	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.000000	0.036344	0.000000	0.776992	0.186664
132	AP	Sales Expense	SALESEXP	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
133	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.046940	0.014586	0.140082	0.159631	0.188991	0.076968
134	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.045946	0.040167	0.231882	0.157695	0.050965	0.052732
135	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
136	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.055340	0.017272	0.215284	0.160199	0.061022	0.040748
137	AP									
138	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.044407	0.048843	0.231962	0.172216	0.018302	0.010764
139	AP									
140	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.045011	0.034062	0.219551	0.172414	0.004685	0.061897
141	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.047921	-0.000297	0.125964	0.081217	0.314825	0.252150
142	AP									
143	AP	**Labor Expense Related**								
144	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.004591	0.000054	0.052575	0.086446	0.000000	0.628908
145	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.163247	0.000683	0.199612	0.204658	0.000000	0.015444
146	AP	Total Labor	LABOR	1.000000	0.047888	0.000210	0.127069	0.082162	0.311719	0.249663
147	AP									
148	AP	**REVENUES AND BILLING DETERMINANTS**								
149	AP									
150	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.044523	0.029595	0.196563	0.159614	0.064709	0.087196
151	AP									
152	AP	Residential Service	REVRS	1.000000	0.000000	0.000106	0.220170	0.170041	0.086518	0.155393
153	AP	Residential Heating Service	REVRHS	1.000000	0.000000	0.124469	0.134011	0.102423	0.078410	0.100916
154	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.621975	0.081753	0.064445	0.024585	0.031184
155	AP	Water Heating Service	REVWH	1.000000	0.000000	0.995807	0.000163	0.000000	0.000355	0.003315
156	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.985085	0.000569	0.000000	0.001269	0.012051
157	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.183806	0.141124	0.205065	0.108201
158	AP	Body Police Lighting Service	REVBLP	1.000000	0.901728	0.000000	0.000435	0.000000	0.007756	0.000003
159	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.528481	0.000000	0.001242	0.000000	0.030046	0.000015
160	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.856957	0.000000	0.000842	0.000000	0.034787	0.000004
161	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
162	**AP**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
163	AP									
164	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.014142	0.254646	0.195216	0.059504	0.061416
165	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000271	0.201068	0.161274	0.037864	0.018309
166	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000342	0.121409	0.215041	0.042222	0.016115
167	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000001	0.003836	0.087185	0.097420	0.032131
168	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.019836	0.000000	0.751423	0.228741
169	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
170	AP									
171	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.044523	0.029595	0.196563	0.159614	0.064709	0.087196
172	AP									
173	AP	**PRESENT REVENUES FROM SALES INPUT**								
174	AP									
175	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
176	AP	Sales of Electricity Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
177	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
178	AP									
179	AP									
180	AP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
181	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
182	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	701,978	0	0	129,028	99,066	143,951	75,955
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	26,795,398	22,962,497	0	22,568	0	932,125	100
38	ADA	General Power and Lighting Service	REVGLP	384,902,021	0	5,443,311	98,013,689	75,139,161	22,903,156	23,638,990
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	102,952	76,299,397	61,198,678	14,368,111	6,947,861
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	24,942	8,841,568	15,660,204	3,074,816	1,173,602
41	ADA	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	43	184,854	4,201,745	4,695,018	1,548,489
42	ADA	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	58,023	0	2,197,961	669,083
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									
45	ADA	Total Late Payment Fees	REVLATEP	915,812,512	22,962,497	5,571,247	183,549,126	156,298,854	48,315,137	34,054,078

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
46	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.025073	0.006083	0.200422	0.170667	0.052757	0.037185
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	----------								
5	RRW	RATE BASE		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982
6	RRW	NET OPER INC (PRESENT RATES)		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
10	RRW	REVENUE PRES RATES $/KWH		$0.0456	$0.0020	$0.0014	$0.0090	$0.0073	$0.0030	$0.0040
11	RRW	REVENUE REQUIRED - $/MO/CUST		$66.11	$2.94	$1.96	$12.99	$10.55	$4.28	$5.76
12	RRW	SALES REV REQUIRED $/KW								
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	----------								
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456
19	RRW	REVENUE DEFICIENCY SALES REV						0		(0)
20	RRW	PERCENT INCREASE REQUIRED								
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564
22	RRW	SALES REV REQUIRED $/KWH		$0.0456	$0.0020	$0.0014	$0.0090	$0.0073	$0.0030	$0.0040
23	RRW	REVENUE DEFICIENCY $/KWH								

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Street Lighting	$82,940,563	0	0	0	0	0	0	$59,591,770
2	Access	$55,131,523	$86,433	$544,133	$14,754,404	$34,030,901	$144,405	0	0
3	Local Delivery Demand	$366,172,706	$180,063,110	$585,845	$1,939,332	$5,578	$83	$129,028	$28,723
4	Local Delivery Energy	$396,670,076	$166,845,741	$1,095,209	$2,267,010	$6,565	$80	$138,109	$3,180,419
5	System Delivery Demand	$297,341,383	$139,066,006	$447,756	$1,528,767			$99,066	
6	System Delivery Energy	$381,643,335	$133,932,620	$914,735	$1,909,409	$5,723	$70	$115,870	$2,772,479
7	Customer Service	$120,545,304	$70,757,324	$342,780	$583,211	$12,139	$186	$143,951	$512,565
8	Measurement	$162,436,456	$127,086,199	$441,165	$739,733	$113,297	$1,767	$75,955	207
9	Total	$1,862,881,345	$817,837,432	$4,371,623	$23,721,865	$34,174,203	$146,591	$701,978	$66,086,163

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Subtransmission	HTS-High Voltage
		(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Street Lighting	$386,296	$22,962,497	0	0	0	0	0
2	Access	0	0	$5,443,311	$102,952	$24,942	$43	
3	Local Delivery Demand	$908	$22,568	$98,013,689	$76,299,397	$8,841,568	$184,854	$58,023
4	Local Delivery Energy	$171,914	$1,537,670	$88,437,768	$118,347,602	$14,529,350	$112,638	
5	System Delivery Demand			$75,139,161	$61,198,678	$15,660,204	$4,201,745	0
6	System Delivery Energy	$149,863	$1,340,439	$71,325,946	$102,205,398	$29,519,937	$37,450,846	
7	Customer Service	$21,962	$932,125	$22,903,156	$14,368,111	$3,074,816	$4,695,018	$2,197,961
8	Measurement	11	100	$23,638,990	$6,947,861	$1,173,602	$1,548,489	$669,083
9	Total	$730,955	$26,795,398	$384,902,021	$379,469,998	$72,824,417	$48,193,633	$2,925,067

EXHIBIT P-9E
Schedule SS-E8

Cost of Service and Rate Design Sync

Step 1: Import Revenue Requirements by Functional Segment and Rate Class from SS-E7

line #	Rate Schedule	(1) Streetlighting	(2) Access	(3) Local Delivery	(4) System Delivery	(5) Customer Service	(6) Measurement	(7) Total
1	RS	$ -	$ 35,857,048	$ 470,258,234	$ 300,953,037	$ 97,613,658	$ 153,746,528	$ 1,058,428,504
2	RHS	$ -	$ 210,055	$ 2,916,480	$ 966,079	$ 339,118	$ 505,049	$ 4,936,781
3	RLM	$ -	$ 350,942	$ 3,599,479	$ 3,384,284	$ 566,570	$ 843,793	$ 8,745,067
4	WH	$ -	$ 1,881	$ 7,458	$ -	$ 10,628	$ 112,408	$ 132,375
5	WHS	$ -	$ 29	$ 113	$ -	$ 166	$ 1,753	$ 2,062
6	HS	$ -	$ -	$ 1,008,585	$ 209,736	$ 12,602	$ 49,213	$ 1,280,136
7	BPL	$ 60,282,175	$ -	$ 2,409,245	$ -	$ 346,312	$ -	$ 63,037,732
8	BPL-POF	$ 382,905	$ -	$ 112,647	$ -	$ 6,300	$ -	$ 501,853
9	PSAL	$ 19,546,381	$ -	$ 1,204,516	$ -	$ 1,645,334	$ -	$ 22,396,231
10	GLP	$ -	$ 18,164,101	$ 127,875,042	$ 156,656,434	$ 22,222,132	$ 24,139,070	$ 349,056,779
11	LPL-S	$ -	$ 1,296,052	$ 102,876,070	$ 126,845,827	$ 8,070,337	$ 10,924,500	$ 250,012,787
12	LPL-P	$ -	$ 109,594	$ 19,712,473	$ 33,170,698	$ 682,427	$ 1,014,542	$ 54,689,734
13	HTS-S	$ -	$ 60,553	$ 23,288,593	$ 25,509,657	$ 167,670	$ 453,817	$ 49,480,290
14	HTS-HV	$ -	$ -	$ 10,433	$ -	$ 22,561	$ 148,020	$ 181,014
15	Total	80,211,461	56,050,255	755,279,369	647,695,752	131,705,815	191,938,693	$ 1,862,881,345
Notes:		SS-E7, Line 1	SS-E7, Line 2	SS-E7, Line 3	SS-E7, Line 4	SS-E7, Line 5	SS-E7, Line 6	SS-E7, Line 7

Step 2: Create Sync Factors

Customer Sync Factor Calc

		Customer Total - Rate Design	Customer Total - COSS	Customer Sync Factor
16	RS	1,981,089	$ 2,000,647	0.990
17	RHS	6,404	$ 6,950	0.921
18	RLM	11,197	$ 11,612	0.964
19	WH	574	$ 662	0.866
20	WHS	11	$ 10	1.040
21	HS	714	$ 789	0.905
22	BPL		$ 4,938	-
23	BPL-POF		$ 90	-
24	PSAL		$ 23,580	-
25	GLP	272,921	$ 288,392	0.946
26	LPL-S	9,379	$ 9,532	0.984
27	LPL-P	770	$ 794	0.970
28	HTS-S	189	$ 195	0.971
29	HTS-HV	16	$ 26	0.622
30	Total	2,283,265	2,348,219	
Notes:		SS-E11 Workpapers	COS Model	(1) / (2)

kWh Sync Factor Calc

	kWh - Rate Design	kWh - COSS	kWh Sync Factor
16	13,096,522,329	$ 13,286,613,062	0.986
17	80,915,936	$ 93,109,748	0.869
18	170,717,425	$ 189,891,666	0.899
19	514,918	$ 581,366	0.886
20	8,213	$ 7,149	1.149
21	7,892,762	$ 11,877,324	0.665
22	285,913,122	$ 283,298,553	1.009
23	14,293,500	$ 15,313,401	0.933
24	137,181,873	$ 137,520,699	0.998
25	7,102,854,741	$ 7,289,563,210	0.974
26	10,208,844,968	$ 10,497,945,935	0.972
27	2,944,784,961	$ 3,083,571,353	0.955
28	4,541,550,576	$ 4,669,504,753	0.973
29	435,990,949	$ 672,466,899	0.648
30	39,027,986,274	40,231,265,119	
Notes:	SS-E11 Workpapers	COS Model	(5) / (6)

Cost of Service and Rate Design Sync

Step 1: Initial Sync

line #	(1) Rate Schedule	(2) Streetlighting	(3) Access	(4) Local Delivery	(5) System Delivery	(6) Customer Service	(7) Measurement	(8) Total
1	RS	$ -	$ 35,506,523.99	$ 463,530,279	$ 296,647,321	$ 96,659,427	$ 152,243,566	$ 1,044,587,117
2	RHS	$ -	$ 193,532.58	$ 2,534,533	$ 839,560	$ 312,444	$ 465,323	$ 4,345,393
3	RLM	$ -	$ 338,403.72	$ 3,236,023	$ 3,042,557	$ 546,328	$ 813,647	$ 7,976,958
4	WH	$ -	$ 1,630.11	$ 6,606	$ -	$ 9,208	$ 97,390	$ 114,834
5	WHS	$ -	$ 30.53	$ 130	$ -	$ 172	$ 1,824	$ 2,157
6	HS	$ -	$ -	$ 670,229	$ 139,375	$ 11,398	$ 44,514	$ 865,515
7	BPL	$ 60,838,521	$ -	$ 2,431,480	$ -	$ 349,508	$ -	$ 63,619,509
8	BPL-POF	$ 357,403	$ -	$ 105,145	$ -	$ 5,880	$ -	$ 468,428
9	PSAL	$ 19,498,222	$ -	$ 1,201,548	$ -	$ 1,641,280	$ -	$ 22,341,050
10	GLP	$ -	$ 17,189,697.80	$ 124,599,763	$ 152,643,974	$ 21,030,039	$ 22,844,143	$ 338,307,616
11	LPL-S	$ -	$ 1,275,219.00	$ 100,042,986	$ 123,352,643	$ 7,940,612	$ 10,748,896	$ 243,360,355
12	LPL-P	$ -	$ 106,271.42	$ 18,825,247	$ 31,677,740	$ 661,737	$ 983,784	$ 52,254,781
13	HTS-S	$ -	$ 58,790.52	$ 22,650,437	$ 24,810,639	$ 162,791	$ 440,611	$ 48,123,268
14	HTS-HV	$ -	$ -	$ 6,764	$ -	$ 14,024	$ 92,011	$ 112,800
15	Total	$ 80,694,146	$ 54,670,100	$ 739,841,169	$ 633,153,809	$ 129,344,850	$ 188,775,708	$ 1,826,479,782
Notes:		2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	2018 Rate Case Schedule SS-E8, page 2, lines 1-15	Sum (Col 2 - Col 7)

Step 2: ES2 Sync

16	Total Rev Req Increase to be Recovered Through Rates	$ 522,084,186	Schedule SS-RC2023-2
17	Total Target Distribution Revenue Requirements	$ 1,769,837,273	= Line 16 + page 4, Col 3, Line 21
18	Rate Case Minus Streetlight Fixtures	$ 1,745,785,636	= col 8, line 15 - col 2, line 15
19	Target Minus Streetlight Fixtures	$ 1,689,143,128	= line 17 - col 2, line 15
20	Final Sync Adjustment Factor	0.96899	= line 17 / (line 15 column 8)

		Streetlighting	Access	Local Delivery	System Delivery	Cust Svs	Measurement	Total
21	RS	$ -	$ 34,405,401	$ 449,155,350	$ 287,447,740	$ 93,661,840	$ 147,522,212	$ 1,012,192,543
22	RHS	$ -	$ 187,531	$ 2,455,932	$ 813,524	$ 302,755	$ 450,893	$ 4,210,634
23	RLM	$ -	$ 327,909	$ 3,135,667	$ 2,948,202	$ 529,385	$ 788,414	$ 7,729,578
24	WH	$ -	$ 1,580	$ 6,401	$ -	$ 8,922	$ 94,370	$ 111,272
25	WHS	$ -	$ 30	$ 126	$ -	$ 167	$ 1,768	$ 2,090
26	HS	$ -	$ -	$ 649,444	$ 135,053	$ 11,045	$ 43,133	$ 838,674
27	BPL	$ 58,951,806	$ -	$ 2,356,075	$ -	$ 338,669	$ -	$ 61,646,551
28	BPL-POF	$ 346,319	$ -	$ 101,884	$ -	$ 5,698	$ -	$ 453,901
29	PSAL	$ 18,893,546	$ -	$ 1,164,286	$ -	$ 1,590,381	$ -	$ 21,648,213
30	GLP	$ -	$ 16,656,614	$ 120,735,695	$ 147,910,202	$ 20,377,858	$ 22,135,704	$ 327,816,073
31	LPL-S	$ -	$ 1,235,672	$ 96,940,468	$ 119,527,250	$ 7,694,359	$ 10,415,553	$ 235,813,302
32	LPL-P	$ -	$ 102,976	$ 18,241,442	$ 30,695,355	$ 641,216	$ 953,275	$ 50,634,263
33	HTS-S	$ -	$ 56,967	$ 21,948,005	$ 24,041,215	$ 157,742	$ 426,947	$ 46,630,877
34	HTS-HV	$ -	$ -	$ 6,554	$ -	$ 13,590	$ 89,158	$ 109,302
35	Total	$ 78,191,671	$ 52,974,679	$ 716,897,329	$ 613,518,541	$ 125,333,628	$ 182,921,425	$ 1,769,837,273
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Notes:		Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Step 1 Rev Req * Line 20	Sum (Col 2 - Col 7)

EXHIBIT P-9E
Schedule SS-E9
Page 1 of 3

Inter Class Revenue Increase Allocations
Calculation of Increase Limits

line #		(in $1,000)		Notes:
1	Requested Revenue Increase to be recovered from rate schedule charges =	$ 522,084		Schedule SS-RC2023-2
2	Present Distribution Revenue =	$ 1,247,753		Page 4, col 3, line 21
3	Present Total Customer Bills (all on BGS) =	$ 5,982,410		Page 4, col 5, line 21
4	Average Distribution Increase =	41.842%		= Line 1 / Line 2
5	Average Total Bill Increase =	8.727%		= Line 1 / Line 3
6	Lower Distribution increase limit =	20.921%	in Distribution charges	= 0.5 * Line 4
7	Upper Distribution increase limit #1 =	52.303%	in Distribution charges	= 1.25 * Line 4
8	Upper Bill increase limit #2 =	13.091%	in Bill Increase	= 1.5 * Line 5

all rounded to 0.001%

EXHIBIT P-9E
Schedule SS-E9

Inter Class Revenue Increase Calculations
Calculation of Increases

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Requirement (from COS) (in $1,000)	(3) Present Distribution Revenue (in $1,000)	(4) Unlimited COS Distribution Charge $ Increase (in $1,000)	(5) Present Total Bill Revenue (all on BGS) (in $1,000)	(6) Unlimited Distribution Charge Increase (%)	(7) Limited Final Distribution Charge Increase (%)	(8) Proposed Total Bill Increase (%)	(9) Proposed Distribution Revenue Increase (in $1,000)
1	RS	$ 1,012,193	$ 622,023	$ 390,170	$ 2,559,664	62.726%	52.303%	12.710%	$ 325,337
2	RHS	$ 4,211	$ 2,908	$ 1,303	$ 13,478	44.818%	52.303%	11.285%	$ 1,521
3	RLM	$ 7,730	$ 6,871	$ 858	$ 48,095	12.490%	20.921%	2.990%	$ 1,438
4	WH *	$ 111.272	$ 25.875	$ 85.397	$ 70.092	330.039%	35.459%	13.090%	$ 9.175
5	WHS *	$ 2.090	$ 0.097	$ 1.993	$ 0.778	2055.149%	52.303%	6.555%	$ 0.051
6	HS	$ 839	$ 513	$ 326	$ 1,976	63.526%	50.305%	13.058%	$ 258
7	BPL	$ 61,647	$ 58,081		$ 81,498				
8	Distribution Only	$ 2,695	$ 1,971	$ 724		36.720%	18.367%	0.444%	$ 362
9	Luminaires and Poles	$ 58,952	$ 56,110	$ 2,842		5.064%	10.000%	0.000%	$ 5,611
10	BPL-POF *	$ 453.901	$ 386.326		$ 1,551.028				
11	Distribution Only	$ 107.582	$ 99.068	$ 8.514		8.594%	20.921%	1.336%	$ 20.726
12	Luminaires and Poles	$ 346.319	$ 287.258	$ 59.062		20.560%	20.607%	0.000%	$ 59.196
13	PSAL	$ 21,648	$ 28,029		$ 39,724				
14	Distribution Only	$ 2,755	$ 1,019	$ 1,736		170.330%	18.552%	0.476%	$ 189
15	Luminaires and Poles	$ 18,894	$ 27,010	$ (8,117)		-30.051%	10.000%	0.000%	$ 2,701
16	GLP	$ 327,816	$ 248,312	$ 79,504	$ 1,106,106	32.018%	42.813%	9.611%	$ 106,311
17	LPL-S	$ 235,813	$ 209,588	$ 26,226	$ 1,267,476	12.513%	20.921%	3.459%	$ 43,848
18	LPL-P	$ 50,634	$ 37,452	$ 13,183	$ 341,578	35.199%	47.067%	5.161%	$ 17,628
19	HTS-S	$ 46,631	$ 31,128	$ 15,502	$ 483,825	49.802%	52.303%	3.365%	$ 16,281
20	HTS-HV	$ 109	$ 2,436	$ (2,326)	$ 37,369	-95.512%	20.921%	1.365%	$ 510
21	Total	$ 1,769,837	$ 1,247,753	$ 522,084	$ 5,982,410	41.842%	41.842%	8.727%	$ 522,084

* WH, WHS and & BPL-POF shown to 3 decimal points

Notes:		Page 2, Step 2, col 8	= (2) - (3)	Page 6	= (4) / (3)	calculated on limits	= (9) / (5)	= (3) * (7)

EXHIBIT P-9E
Schedule SS-E9
Page 3 of 3

Inter Class Revenue Increase Calculations
Calculation of Increases

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Increase (in $1,000)	(3) Proposed TAC Change (in $1,000)	(4) Proposed DAC - SRC (in $1,000)	(5) Net Distribution Revenue Increase (in $1,000)	(6) Net Total Bill Increase (%)
1	RS	$ 325,337	$ (70,572)	$ 12,842	$ 267,607	10.5%
2	RHS	$ 1,521	$ (624)	$ 71	$ 968	7.2%
3	RLM	$ 1,438	$ (896)	$ 168	$ 710	1.5%
4	WH *	$ 9.175	$ -	$ 0.531	$ 9.706	13.8%
5	WHS *	$ 0.051	$ -	$ 0.007	$ 0.058	7.4%
6	HS	$ 258	$ 13	$ 9	$ 280	14.2%
7	BPL	$ -	$ -	$ -	$ -	
8	Distribution Only	$ 362	$ -	$ 239	$ 601	
9	Luminaires and Poles	$ 5,611	$ -	$ -	$ 5,611	
10	BPL-POF *	$ -	$ -	$ -	$ -	0.0%
11	Distribution Only	$ 20.726	$ 6.561	$ 13.406	$ 40.692	
12	Luminaires and Poles	$ 59.196	$ -	$ -	$ 59.196	
13	PSAL	$ -	$ -	$ -	$ -	0.0%
14	Distribution Only	$ 189	$ -	$ 104	$ 293	
15	Luminaires and Poles	$ 2,701	$ -	$ -	$ 2,701	
16	GLP	$ 106,311	$ (11,697)	$ 6,633	$ 101,247	9.2%
17	LPL-S	$ 43,848	$ (10,102)	$ 9,610	$ 43,355	3.4%
18	LPL-P	$ 17,628	$ (1,690)	$ 2,764	$ 18,703	5.5%
19	HTS-S	$ 16,281	$ (2,499)	$ 4,860	$ 18,643	3.9%
20	HTS-HV	$ 510	$ (108)	$ 643	$ 1,044	2.8%
21	Total	$ 522,084	$ (98,168)	$ 37,957	$ 461,874	7.7%

* WH, WHS and & BPL-POF shown to 3 decimal points

Notes:	Page 2, Col 9	SS-TAC-6E row 18	SS-SRC-3E, col 3	= (2) + (3) + (4)	= Col 4 / Page 2 Col 5

Service Charge Calculations

Service charges are comprised of revenue requirements for the Distribution Access and Measurement segments related to Minimum Size Facilities, plus the Revenue Requirements for the Customer Service segment.

line #	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Average Distribution Increase =		41.842%	page 3, Line 4						
	Rate Schedule	Access Segment Revenue Requirement	Measurement Segment Revenue Requirement	Customer Service Segment Revenue Requirements	Rev Req to be recovered through Service Charge	# of Customers	Cost Based Monthly Service Charge ($/month)	Current Monthly Service Charge ($/month)	Proposed Limited Monthly Service Charge ($/month)	
2	RS	$ 34,405,401	$ 147,522,212	$ 93,661,840	$ 275,589,453	1,981,089	$ 11.59	$ 4.64	$ 7.55	see Note 2
3	RHS	$ 187,531	$ 450,893	$ 302,755	$ 941,178	6,404	$ 12.25	$ 4.64	$ 7.55	set equal to RS
4	RLM	$ 327,909	$ 788,414	$ 529,385	$ 1,645,708	11,197	$ 12.25	$ 13.07	$ 13.07	see Note 2
5	WH	no service charge								
6	WHS	$ 30	$ 1,768	$ 167	$ 1,964	11	$ 15.23	$ 0.63	$ 1.03	see Note 2
7	HS	$ -	$ 43,133	$ 11,045	$ 54,178	714	$ 6.32	$ 3.75	$ 6.10	see Note 2
8	BPL	no service charge								
9	BPL-POF	no service charge								
10	PSAL	no service charge								
11	GLP	$ 16,656,614	$ 22,135,704	$ 20,377,858		272,921				
12	GLP Metered					256,116	$ 18.51	$ 4.78	$ 7.78	see Note 3
13	GLP Unmetered					5,766	$ 11.31	$ 2.20	$ 3.58	see Note 4
14	GLP-NU					64			$ 7.78	see Note 3
15	LPL-S	$ 1,235,672	$ 10,415,553	$ 7,694,359	$ 19,345,583	9,379	$ 171.88	$ 347.77	$ 347.77	see Note 2
16	LPL-P	$ 102,976	$ 953,275	$ 641,216	$ 1,697,467	770	$ 183.73	$ 347.77	$ 347.77	see Note 2
17	LPL-P <100 kW						$ 114.49	$ 21.58	$ 35.12	see Note 5
18	HTS-S	$ 56,967	$ 426,947	$ 157,742	$ 641,657	189	$ 282.31	$ 1,911.39	$ 1,911.39	see Note 2
19	HTS-HV	$ -	$ 89,158	$ 13,590	$ 102,747	16	$ 524.73	$ 1,720.25	$ 1,720.25	see Note 2
Source:		for Cols 2, 3 and 4 from Page 2, Cols 3, 6 & 7 from Step 2			= (2) + (3) + (4)	2018 Rate Case SS-E8 R-2, Step 2, Col 1	= (5) / (6) / 12	From Tariff	based on methodology described	

Notes:
1 Agreed upon in Settlement
2 Move toward cost limited at no decrease from current service charge and no increase greater than 1.5 times the overall average distribution % increase.
3 Access and Customer Service Rev Req per total GLP Customer plus Measurement Rev Req divided by the number of metered customers divided by 12; limits the same as Note 2
4 Access and Customer Service Rev Req per total GLP Customer divided by 12; limits the same as Note 2
5 Calculated at the GLP Access Segment per customer plus the GLP Customer Service Segment Revenue Requirements per customer plus the LPL-P Measurement Segment per customer divided by 12; limits the same as Note 2

Electric Proof of Revenue by Rate Schedule
Explanation of Format

The summary and each rate schedule provide the details of 1) a) Actual and b) Weather Normalized and also 2) a) Annualized Weather Normalized (all customers assumed to be on BGS and revenue based on current tariff rates) and b) the proposed rate design.

1) Actual and Weather Normalized

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Zero Emission Certificate Recovery Charge, Solar Pilot Recovery Charge, Green Programs Recovery Charge, Conservation Incentive Program, Tax Adjustment Credit, CIEP Standby Fee (as applicable), Facilities Charges, Miscellaneous items, Minimums, and Unbilled Revenue. The first column shows the actual billing units for the test year from Schedule SS-E2. The second column shows annual average rates (without Sales and Use Tax, SUT) occurring during the test period. The third column presents annualized revenue for the test period. The fourth column shows the weather normalized billing units for the test year from SS-E2. The fifth column shows the applicable rates. Column 6 presents weather normalized revenue. Columns 7 and 8 show the differential revenue, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

2) Annualized Weather Normalized (all customers assumed to be on BGS) and the Proposed rate design.

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Securitization Transition Charges, Solar Pilot Recovery Charge, CIEP Standby Fee (as applicable), Green Programs Recovery Charge, Tax Adjustment Credit, Green Enabling Mechanism, Facilities Charges, Miscellaneous items, Minimums, and Unbilled Revenue. The first column shows the annualized weather normalized billing units for the test year from Schedule SS-E2. The second column shows present Delivery rates (without Sales and Use Tax, SUT) effective November 1, 2023. The Supply-BGS rates in the second column reflect the rates in effect November 1, 2023 and for CIEP energy, reflect the latest available 12-month class average hourly rates. The third column presents annualized revenue for the test period assuming all customers are provided service under their applicable BGS provision. The fourth column repeats the billing units of the first column. The fifth column shows the proposed rates that result in the proposed revenues shown in column 6. Columns 7 and 8 show the proposed revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

WEATHER NORMALIZED
SUMMARY
Rate Case 2023
(kWhrs & Revenue in Thousands)

	Rate Schedule		Actual		Weather Normalized		Difference	
			kWhrs	Revenue	kWhrs	Revenue	Revenue	Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	RS	13,096,522	$2,464,389	13,044,353	$2,454,221	($10,168)	(0.41)
2	Residential Heating	RHS	82,990	12,455	83,042	12,556	101	0.81
3	Residential Load Management	RLM	177,462	31,653	176,965	31,634	(19)	(0.06)
4	Water Heating	WH	523	69	523	69	0	0.67
5	Water Heating Storage	WHS	8	0.782	8	0.782	0	0.00
6								
7	Building Heating	HS	10,341	1,639	10,350	1,659	19	1.18
8	General Lighting and Power	GLP	7,102,855	1,001,231	7,084,026	998,312	(2,919)	(0.29)
9	Large Power & Lighting-Sec	LPL-S	10,208,845	801,569	10,200,967	800,441	(1,128)	(0.14)
10	Large Power & Lighting-Pri	LPL-P	2,944,785	151,494	2,944,785	151,494	0	0.00
11	High Tension-Subtr.	HTS-S	4,541,551	176,692	4,541,551	176,692	0	0.00
12	High Tension-HV	HTS-HV	435,991	11,141	435,991	11,141	0	0.00
13								
14	Body Politic Ligting	BPL	285,913	78,865	285,913	78,865	0	0.00
15	Body Politic Ligting-POF	BPL-POF	14,294	1,414	14,294	1,414	0	0.00
16	Private Street & Area Lighting	PSAL	137,182	39,229	137,182	39,229	0	0.00
17								
18								
19	Totals		39,039,260	$4,771,841	38,959,950	$4,757,727	($14,114)	(0.30)
20								
21								
22								
23								
24	Notes:	WHS revenues shown to 3 decimals						

ELECTRIC PROOF OF REVENUE
SUMMARY
ELECTRIC RATE INCREASE
Rate Case 2023
(kWhrs & Revenue in Thousands)

	Rate Schedule		Annualized Weather Normalized kWhrs (1)	Annualized Weather Normalized Revenue (2)	Proposed kWhrs (3)	Proposed Revenue (4)	Increase Revenue (5)	Increase Percent (6)
1	Residential	RS	13,044,353	$2,559,664	13,044,353	$2,885,001	$325,337	12.71
2	Residential Heating	RHS	83,042	13,478	83,042	14,999	1,521	11.29
3	Residential Load Management	RLM	176,965	48,095	176,965	49,533	1,438	2.99
4	Water Heating	WH	523	70.092	523	79.267	9.175	13.09
5	Water Heating Storage	WHS	8	0.778	8	0.829	0.051	6.56
6								
7	Building Heating	HS	10,350	1,976	10,350	2,234	258	13.06
8	General Lighting and Power	GLP	7,084,026	1,106,106	7,084,026	1,212,417	106,311	9.61
9	Large Power & Lighting-Sec	LPL-S	10,200,967	1,267,476	10,200,967	1,311,324	43,848	3.46
10	Large Power & Lighting-Pri	LPL-P	2,944,785	341,578	2,944,785	359,206	17,628	5.16
11	High Tension-Subtr.	HTS-S	4,541,551	483,825	4,541,551	500,106	16,281	3.37
12	High Tension-HV	HTS-HV	435,991	37,369	435,991	37,879	510	1.36
13								
14	Body Politic Lighting	BPL	285,913	81,498	285,913	87,471	5,973	7.33
15	Body Politic Lighting-POF	BPL-POF	14,294	1,551.028	14,294	1,630.950	79.922	5.15
16	Private Street & Area Lighting	PSAL	137,182	39,724	137,182	42,614	2,890	7.28
17								
18								
19	Totals		38,959,950	$5,982,410	38,959,950	$6,504,495	$522,084	8.73
20								
21								
22	Notes:	All customers assumed to be on BGS.						
23		WH, WHS & BPL-POF revenues shown to 3 decimals.						
24		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023						

RATE SCHEDULE RS
RESIDENTIAL SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	23,773.07	4.64	$110,307	23,773.07	4.64	$110,307	0.00	0.00
2	Distribution 0-600 June - September	3,516,236	0.042764	150,369	3,484,965	0.042782	149,095	(1273.72)	(0.85)
3	Distribution 0-600 October - May	6,004,936	0.033330	200,143	6,024,935	0.033325	200,779	636.51	0.32
4	Distribution over 600 June - September	1,966,770	0.051622	101,528	1,921,436	0.051616	99,176	(2352.15)	(2.32)
5	Distribution over 600 October - May	1,608,581	0.033619	54,079	1,613,017	0.033620	54,229	150.18	0.28
6	SBC	13,096,522	0.009969	130,559	13,044,353	0.009966	130,003	(556.67)	(0.43)
7	NGC	13,096,522	0.000015	198	13,044,353	0.000015	197	(1.25)	(0.63)
8	DAC	13,096,522	0.000000	0	13,044,353	0.000000	0	0.00	0.00
9	STC-MTC-Tax	13,096,522	0.000000	0	13,044,353	0.000000	0	0.00	0.00
10	ZECRC	13,096,522	0.004000	52,386	13,044,353	0.004000	52,177	(208.91)	(0.40)
11	Solar Pilot Recovery Charge	13,096,522	0.000062	818	13,044,353	0.000062	814	(3.29)	(0.40)
12	Green Programs Recovery Charge	13,096,522	0.004920	64,435	13,044,353	0.004920	64,178	(256.67)	(0.40)
13	Tax Adjustment Credit	13,096,522	(0.005466)	(71,581)	13,044,353	(0.005471)	(71,359)	221.59	(0.31)
14	ECIP	13,096,522	0.000170	2,227	13,044,353	0.000165	2,151	(76.81)	(3.45)
15	Green Enabling Mechanism	13,096,522	0.000000	0	13,044,353	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(909)			(909)	0.03	0.00
19	Delivery Subtotal	13,096,522		$794,559	13,044,353		$790,838	(3721.17)	(0.47)
20	Unbilled Delivery			5,910			4,486	(1424.14)	(24.10)
21	Delivery Subtotal w unbilled			$800,469			$795,324	(5145.31)	(0.64)
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	3,361,440	0.306055	$1,028,787	3,331,905	0.308177	$1,026,818	($1,969)	(0.19)
25	BGS 0-600 October - May	5,888,311	0.000000	0	5,906,859	0.000000	0	0	0.00
26	BGS over 600 June - September	1,894,417	0.108135	204,852	1,850,958	0.109600	202,866	(1987)	(0.97)
27	BGS over 600 October - May	1,575,510	0.000000	0	1,579,452	0.000000	0	0	0.00
28	Transmission	12,719,677	0.033886	$431,017	12,669,174	0.033771	$427,846	($3,171)	(0.74)
29	BGS Reconciliation-RSCP	12,719,677	(0.000260)	(3,310)	12,669,174	(0.000213)	(2,695)	614	(18.56)
30	Miscellaneous			(0)			(0)	(0)	3.38
31	Supply subtotal	12,719,677		$1,661,346	12,669,174		$1,654,834	($6,513)	(0.39)
32	Unbilled Supply			2,573			4,063	1,490	57.91
33	Supply subtotal w unbilled			$1,663,919			$1,658,897	($5,023)	(0.30)
34									
35	Total Delivery + Supply	13,096,522		$2,464,389	13,044,353		$2,454,221	($10,168)	(0.41)
36									
37	Notes:	Rates are annual averages derived from actual, excluding SUT.							

Filing "5 and 7"

RATE SCHEDULE RS
RESIDENTIAL SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

EXHIBIT P-9E
Schedule SS-E11
Page 5 of 43

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	23,773.07	$4.64	$110,307	23,773.07	$7.55	$179,487	$69,180	62.72
2	Distribution 0-600 June - September	3,484,965	0.045704	159,277	3,484,965	0.076528	266,697	107,420	67.44
3	Distribution 0-600 October - May	6,024,935	0.033344	200,895	6,024,935	0.044823	270,056	69,161	34.43
4	Distribution over 600 June - September	1,921,436	0.049525	95,159	1,921,436	0.080349	154,385	59,226	62.24
5	Distribution over 600 October - May	1,613,017	0.033344	53,784	1,613,017	0.044823	72,300	18,516	34.43
6	SBC	13,044,353	0.007767	101,315	13,044,353	0.007767	101,315	0	0.00
7	NGC	13,044,353	0.000024	313	13,044,353	0.000024	313	0	0.00
8	DAC	13,044,353	0.000000	0	13,044,353	0.000000	0	0	0.00
9	STC-MTC-Tax	13,044,353	0.000000	0	13,044,353	0.000000	0	0	0.00
10	ZECRC	13,044,353	0.004000	52,177	13,044,353	0.004000	52,177	0	0.00
11	Solar Pilot Recovery Charge	13,044,353	0.000063	822	13,044,353	0.000063	822	0	0.00
12	Green Programs Recovery Charge	13,044,353	0.004920	64,178	13,044,353	0.004920	64,178	0	0.00
13	Tax Adjustment Credit	13,044,353	(0.001853)	(24,171)	13,044,353	(0.001853)	(24,171)	0	0.00
14	ECIP	13,044,353	0.000271	3,535	13,044,353	0.000271	3,535	0	0.00
15	Green Enabling Mechanism	13,044,353	0.000000	0	13,044,353	0.000000	0	0	0.00
16	Facilities Chg.			0			0	0	0.00
17	Minimum			0			0	0	0.00
18	Miscellaneous			(909)			(910)	(1)	0.11
19	Delivery Subtotal	13,044,353		$816,682	13,044,353		$1,140,184	$323,502	39.61
20	Unbilled Delivery			4,633			6,468	1,835	39.61
21	Delivery Subtotal w unbilled			$821,315			$1,146,652	$325,337	39.61
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	3,484,965	0.072237	$251,743	3,484,965	0.072237	$251,743	$0	0.00
25	BGS 0-600 October - May	6,024,935	0.075527	455,045	6,024,935	0.075527	455,045	0	0.00
26	BGS over 600 June - September	1,921,436	0.081381	156,368	1,921,436	0.081381	156,368	0	0.00
27	BGS over 600 October - May	1,613,017	0.075527	121,826	1,613,017	0.075527	121,826	0	0.00
28	Transmission	13,044,353	0.057428	$749,111	13,044,353	0.057428	$749,111	0	0.00
29	BGS Reconciliation-RSCP	13,044,353	0.000000	0	13,044,353	0.000000	0	0	0.00
30	Miscellaneous			(0)			(0)	0	0.00
31	Supply Subtotal	13,044,353		$1,734,093	13,044,353		$1,734,093	$0	0.00
32	Unbilled Supply			4,257			4,257	0	0.00
33	Supply Subtotal w unbilled			$1,738,350			$1,738,350	$0	0.00
34									
35	Total Delivery + Supply	13,044,353		$2,559,664	13,044,353		$2,885,001	$325,337	12.71
36									
37	Notes:	All customers assumed to be on BGS.							
38		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	76.84	4.64	$357	76.84	4.64	$357	0.00	0.00
2	Distribution 0-600 June - September	12,550	0.051059	641	12,457	0.051074	636	(4.58)	(0.71)
3	Distribution 0-600 October - May	24,818	0.035355	877	24,996	0.035368	884	6.60	0.75
4	Distribution over 600 June - September	5,998	0.060926	365	5,908	0.060925	360	(5.48)	(1.50)
5	Distribution over 600 October - May	39,623	0.017430	691	39,681	0.017431	692	1.01	0.15
6	SBC	82,990	0.010160	843	83,042	0.010155	843	0.04	0.01
7	NGC	82,990	0.000011	1	83,042	0.000011	1	0.00	0.14
8	DAC	82,990	0.000000	0	83,042	0.000000	0	0.00	0.00
9	STC-MTC-Tax	82,990	0.000000	0	83,042	0.000000	0	0.00	0.00
10	ZECRC	82,990	0.004000	332	83,042	0.004000	332	0.21	0.06
11	Solar Pilot Recovery Charge	82,990	0.000062	5	83,042	0.000062	5	0.00	0.06
12	Green Programs Recovery Charge	82,990	0.004920	408	83,042	0.004920	409	0.26	0.06
13	Tax Adjustment Credit	82,990	(0.006807)	(565)	83,042	(0.006810)	(565)	(0.61)	0.11
14	ECIP	82,990	0.000157	13	83,042	0.000155	13	(0.17)	(1.32)
15	Green Enabling Mechanism	82,990	0.000000	0	83,042	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(4)			(4)	0.03	(0.57)
19	Delivery Subtotal	82,990		$3,964	83,042		$3,961	(2.68)	(0.07)
20	Unbilled Delivery			3			12	8.61	293.30
21	Delivery Subtotal w unbilled			$3,967			$3,973	5.93	0.15
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	11,163	0.294433	$3,287	11,087	0.296903	$3,292	$5	0.15
25	BGS 0-600 October - May	24,173	0.000000	0	24,333	0.000000	0	0	0.00
26	BGS over 600 June - September	6,501	0.512181	3,329	6,414	0.518785	3,328	(2)	(0.06)
27	BGS over 600 October - May	39,080	0.000000	0	39,142	0.000000	0	0	0.00
28	Transmission	80,916	0.024938	$2,018	80,976	0.024946	$2,020	$2	0.10
29	BGS Reconciliation-RSCP	80,916	(0.000179)	(15)	80,976	(0.000172)	(14)	1	(4.18)
30	Miscellaneous			0			0	0	0.00
31	Supply subtotal	80,916		$8,620	80,976		$8,625	$6	0.07
32	Unbilled Supply			(132)			(43)	89	(67.52)
33	Supply subtotal w unbilled			$8,488			$8,583	$95	1.11
34									
35	Total Delivery + Supply	82,990		$12,455	83,042		$12,556	$101	0.81
36									
37									
38									
39									
40	Notes: Rates are annual averages derived from actual, excluding SUT.								

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	76.84	$4.64	$357	76.84	$7.55	$580	$223	62.46
2	Distribution 0-600 June - September	12,457	0.052835	658	12,457	0.085167	1,061	403	61.25
3	Distribution 0-600 October - May	24,996	0.034719	868	24,996	0.045533	1,138	270	31.11
4	Distribution over 600 June - September	5,908	0.057735	341	5,908	0.090067	532	191	56.01
5	Distribution over 600 October - May	39,681	0.017119	679	39,681	0.027933	1,108	429	63.18
6	SBC	83,042	0.007767	645	83,042	0.007767	645	0	0.00
7	NGC	83,042	0.000024	2	83,042	0.000024	2	0	0.00
8	DAC	83,042	0.000000	-	83,042	0.000000	0	0	0.00
9	STC-MTC-Tax	83,042	0.000000	-	83,042	0.000000	0	0	0.00
10	ZECRC	83,042	0.004000	332	83,042	0.004000	332	0	0.00
11	Solar Pilot Recovery Charge	83,042	0.000063	5	83,042	0.000063	5	0	0.00
12	Green Programs Recovery Charge	83,042	0.004920	409	83,042	0.004920	409	0	0.00
13	Tax Adjustment Credit	83,042	(0.002623)	(218)	83,042	(0.002623)	(218)	0	0.00
14	ECIP	83,042	0.000271	23	83,042	0.000271	23	0	0.00
15	Green Enabling Mechanism	83,042	0.000000	-	83,042	0.000000	0	0	0.00
16	Facilities Chg.			-			0	0	0.00
17	Minimum			-			0	0	0.00
18	Miscellaneous			(4)			(3)	1	(22.37)
19	Delivery Subtotal	83,042		$4,097	83,042		$5,614	$1,517	37.03
20	Unbilled Delivery			12			16	4	33.33
21	Delivery Subtotal w unbilled			$4,109			$5,630	$1,521	37.02
22									
23	**Supply-BGS**								
24	BGS 0-600 June - September	12,457	0.068808	$857	12,457	0.068808	$857	$0	0.00
25	BGS 0-600 October - May	24,996	0.076746	1,918	24,996	0.076746	1,918	0	0.00
26	BGS over 600 June - September	5,908	0.081036	479	5,908	0.081036	479	0	0.00
27	BGS over 600 October - May	39,681	0.076746	3,045	39,681	0.076746	3,045	0	0.00
28	Transmission	83,042	0.037541	3,117	83,042	0.037541	3,117	0	0.00
29	BGS Reconciliation-RSCP	83,042	0.000000	0	83,042	0.000000	0	0	0.00
30	Miscellaneous			0			0	0	0.00
31	Supply Subtotal	83,042		$9,416	83,042		$9,416	$0	0.00
32	Unbilled Supply			(47)			(47)	0	0.00
33	Supply Subtotal w unbilled			$9,369			$9,369	$0	0.00
34									
35	Total Delivery + Supply	83,042		$13,478	83,042		$14,999	$1,521	11.29
36									
37									
38	Notes:	All customers assumed to be on BGS.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	134.37	13.07	$1,756	134.37	13.07	$1,756	0.00	0.00
2	Distribution June - September On Peak	37,548	0.074178	2,785	37,120	0.074172	2,753	(32.00)	(1.15)
3	Distribution June - September Off Peak	41,034	0.016728	686	40,625	0.016725	679	(6.96)	(1.01)
4	Distribution October - May On Peak	42,718	0.016181	691	42,872	0.016186	694	2.72	0.39
5	Distribution October - May Off Peak	56,161	0.016506	927	56,348	0.016521	931	3.88	0.42
6	SBC	177,462	0.009976	1,770	176,965	0.009973	1,765	(5.39)	(0.30)
7	NGC	177,462	0.000015	3	176,965	0.000015	3	(0.01)	(0.44)
8	DAC	177,462	0.000000	0	176,965	0.000000	0	0.00	0.00
9	STC-MTC-Tax	177,462	0.000000	0	176,965	0.000000	0	0.00	0.00
10	ZECRC	177,462	0.004000	710	176,965	0.004000	708	(1.99)	(0.28)
11	Solar Pilot Recovery Charge	177,462	0.000062	11	176,965	0.000062	11	(0.03)	(0.28)
12	Green Programs Recovery Charge	177,462	0.004920	873	176,965	0.004920	871	(2.45)	(0.28)
13	Tax Adjustment Credit	177,462	(0.005007)	(889)	176,965	(0.005011)	-887	1.79	(0.20)
14	ECIP	177,462	0.000906	161	176,965	0.000902	160	(1.12)	(0.70)
15	Green Enabling Mechanism	177,462	0.000000	0	176,965	0.000000	0	0.00	0.00
16	Facilities Chg.			0			0	0.00	0.00
17	Minimum			0			0	0.00	0.00
18	Miscellaneous			(24)			-24	(0.10)	0.41
19	Delivery Subtotal	177,462		$9,462	176,965		$9,420	(41.65)	(0.44)
20	Unbilled Delivery			45			50	5.00	11.12
21	Delivery Subtotal w unbilled			$9,507			$9,470	(36.65)	(0.39)
22									
23	**Supply-BGS**								
24	BGS Sum On	35,282	0.119800	$4,227	34,909	0.119844	$4,184	($43)	(1.02)
25	BGS Sum Off	42,021	0.164374	6,907	42,136	0.163349	6,883	(24)	(0.35)
26	BGS Win On	38,709	0.035102	1,359	38,361	0.035085	1,346	(13)	(0.94)
27	BGS Win Off	55,172	0.048615	2,682	55,311	0.048335	2,673	(9)	(0.33)
28	Transmission	171,183	0.025028	$4,284	170,717	0.024828	$4,239	($46)	(1.07)
29	BGS Reconciliation-RSCP	171,183	(0.000186)	(32)	170,717	(0.000154)	(26)	6	(17.45)
30	Miscellaneous			2,730			2,791	61	2.25
31	Supply subtotal	171,183		$22,157	170,717		$22,090	($68)	(0.31)
32	Unbilled Supply			(12)			74	85	(732.38)
33	Supply subtotal w unbilled			$22,146			$22,163	$18	0.08
34									
35	Total Delivery + Supply	177,462		$31,653	176,965		$31,634	($19)	(0.06)
36									
37									
38									
39									
40	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	134.37	13.07	$1,756	134.37	13.07	$1,756	$0	0.00
2	Distribution June - September On Peak	37,120	0.076937	2,856	37,120	0.104311	3,872	1016	35.57
3	Distribution June - September Off Peak	40,625	0.016062	653	40,625	0.019028	773	120	18.38
4	Distribution October - May On Peak	42,872	0.016062	689	42,872	0.019028	816	127	18.43
5	Distribution October - May Off Peak	56,348	0.016062	905	56,348	0.019028	1,072	167	18.45
6	SBC	176,965	0.007767	1,374	176,965	0.007767	1,374	0	0.00
7	NGC	176,965	0.000024	4	176,965	0.000024	4	0	0.00
8	DAC	176,965	0.000000	0	176,965	0.000000	0	0	0.00
9	STC-MTC-Tax	176,965	0.000000	0	176,965	0.000000	0	0	0.00
10	ZECRC	176,965	0.004000	708	176,965	0.004000	708	0	0.00
11	Solar Pilot Recovery Charge	176,965	0.000063	11	176,965	0.000063	11	0	0.00
12	Green Programs Recovery Charge	176,965	0.004920	871	176,965	0.004920	871	0	0.00
13	Tax Adjustment Credit	176,965	(0.001739)	(308)	176,965	(0.001739)	(308)	0	0.00
14	ECIP	176,965	0.000965	171	176,965	0.000965	171	0	0.00
15	Green Enabling Mechanism	176,965	0.000000	0	176,965	0.000000	0	0	0.00
16	Facilities Chg.			0			0	0	0.00
17	Minimum			0			0	0	0.00
18	Miscellaneous			(24)			(24)	0	0.00
19	Delivery Subtotal	176,965		$9,666	176,965		$11,096	$1,430	14.79
20	Unbilled Delivery			51			59	8	15.69
21	Delivery Subtotal w unbilled			$9,717			$11,155	$1,438	14.80
22									
23	**Supply-BGS**								
24	BGS June - September On Peak	37,120	0.094156	$3,495	37,120	0.094156	$3,495	$0	0.00
25	BGS June - September Off Peak	40,625	0.059459	2,415	40,625	0.059459	2,415	0	0.00
26	BGS October - May On Peak	42,872	0.089221	3,825	42,872	0.089221	3,825	0	0.00
27	BGS October - May Off Peak	56,348	0.064475	3,633	56,348	0.064475	3,633	0	0.00
28	Transmission - On Peak	176,965	0.124829	22,090	176,965	0.124829	22,090	0	0.00
29	BGS Reconciliation-RSCP	176,965	0.000000	0	176,965	0.000000	0	0	0.00
30	Miscellaneous			2,791			2,791	0	0.00
31	Supply Subtotal	176,965		$38,249	176,965		$38,249	$0	0.00
32	Unbilled Supply			128			128	0	0.00
33	Supply Subtotal w unbilled			$38,377			$38,377	$0	0.00
34									
35	Total Delivery + Supply	176,965		$48,095	176,965		$49,533	$1,438	2.99
36									
37									
38	Notes:	All customers assumed to be on BGS.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Distribution Sum	156.788	0.048948	$8	156.793	0.048948	$8	0.00	0.00
2	Distribution Win	366	0.049845	18.247	366	0.049845	18.250	0.00	0.02
3	SBC	523	0.010022	5.240	523	0.010022	5.241	0.00	0.01
4	NGC	523	0.000013	0.007	523	0.000013	0.007	0.00	0.02
5	DAC	523	0.000000	0.000	523	0.000000	0.000	0.00	0.00
6	STC-MTC-Tax	523	0.000000	0.000	523	0.000000	0.000	0.00	0.00
7	ZECRC	523	0.004005	2.094	523	0.004005	2.094	0.00	0.01
8	Solar Pilot Recovery Charge	523	0.000062	0.033	523	0.000062	0.033	0.00	0.01
9	Green Programs Recovery Charge	523	0.004920	2.573	523	0.004920	2.573	0.00	0.01
10	Tax Adjustment Credit	523	(0.000034)	-0.018	523	(0.000034)	-0.018	0.00	0.00
11	Green Enabling Mechanism	523	0.000000	0	523	0.000000	0	0.00	0.00
12	Facilities Chg.			0			0	0.00	0.00
13	Minimum			0			0	0.00	0.00
14	Miscellaneous			0			0	0.00	0.00
15	Delivery Subtotal	523		$36	523		$36	0.00	0.01
16	Unbilled Delivery			(0)			0	0.23	-117.61
17	Delivery Subtotal w unbilled			$36			$36	0.23	0.65
18									
19	**Supply-BGS**								
20	BGS Summer	155	0.065477	$10	155	0.065477	$10	0.00	0.00
21	BGS Winter	360	0.064844	23	360	0.064844	23	0	0.02
22	BGS Reconciliation-RSCP	515	(0.000435)	(0)	515	(0.000436)	(0)	0	0.19
23	Miscellaneous			0			0	0	0.00
24	Supply subtotal	515		$33	515		$33	$0	0.01
25	Unbilled Supply			-0.192			0.034	0.23	-117.61
26	Supply subtotal w unbilled			$33			$33	$0	0.70
27									
28	Total Delivery + Supply	523		$69	523		$69	$0	0.67
29									
30									
31									
32	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE WH
WATER HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Distribution Sum	156.793	0.049482	$7.758	156.793	0.067026	$10.509	$2.751	35.46
2	Distribution Win	366	0.049482	$18.117	366	0.067026	$24.541	$6.424	35.46
3	SBC	523	0.007767	$4.062	523	0.007767	$4.062	$0.000	0.00
4	NGC	523	0.000024	$0.013	523	0.000024	$0.013	$0.000	0.00
5	DAC	523	0.000000	$0.000	523	0.000000	$0.000	$0.000	0.00
6	STC-MTC-Tax	523	0.000000	$0.000	523	0.000000	$0.000	$0.000	0.00
7	ZECRC	523	0.004000	$2.092	523	0.004000	$2.092	$0.000	0.00
8	Solar Pilot Recovery Charge	523	0.000063	$0.033	523	0.000063	$0.033	$0.000	0.00
9	Green Programs Recovery Charge	523	0.004920	$2.573	523	0.004920	$2.573	$0.000	0.00
10	Tax Adjustment Credit	523	0.000000	$0.000	523	0.000000	$0.000	$0.000	0.00
11	Green Enabling Mechanism	523	0.000000	$0.000	523	0.000000	$0.000	$0.000	0.00
12	Facilities Chg.			$0.000			$0.000	$0.000	0.00
13	Minimum			$0.000			$0.000	$0.000	0.00
14	Miscellaneous			$0.000			-$0.009	-$0.009	0.00
15	Delivery Subtotal	523		$34.648	523		$43.814	$9.166	26.45
16	Unbilled Delivery			$0.033			$0.042	$0.009	27.27
17	Delivery Subtotal w unbilled			$34.681			$43.856	$9.175	26.46
18									
19	**Supply-BGS**								
20	BGS Summer	157	0.066577	$10.439	157	0.066577	$10.439	$0.000	0.00
21	BGS Winter	366	0.068204	$24.972	366	0.068204	$24.972	$0.000	0.00
22	BGS Reconciliation-RSCP	523	0.000000	$0.000	523	0.000000	$0.000	$0.000	0.00
23	Miscellaneous			$0.000			$0.000	$0.000	0.00
24	Supply Subtotal	523		$35.411	523		$35.411	$0.000	0.00
25	Unbilled Supply			$0.000			$0.000	$0.000	0.00
26	Supply Subtotal w unbilled			$35.411			$35.411	$0.000	0.00
27									
28	Total Delivery + Supply	523		$70.092	523		$79.267	$9.175	13.09
29									
30									
31									
32	Notes:	All customers assumed to be on BGS.							
33		WH, WHS & BPL-POF revenues shown to 3 decimals.							
34		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							
35									
36									
37									
38									

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.129	0.62	$0.080	0.129	0.62	$0.080	0.00	0.00
2	Distribution June - September	1.895	0.001760	0.003	1.895	0.001760	0.003	0.00	0.00
3	Distribution October - May	6.318	0.002038	0.013	6.318	0.002038	0.013	0.00	0.00
4	SBC	8.213	0.010379	0.085	8.213	0.010379	0.085	0.00	0.00
5	NGC	8.213	0.000010	0.000	8.213	0.000010	0.000	0.00	0.00
6	DAC	8.213	0.000000	0.000	8.213	0.000000	0.000	0.00	0.00
7	STC-MTC-Tax	8.213	0.000000	0.000	8.213	0.000000	0.000	0.00	0.00
8	ZECRC	8.213	0.004003	0.033	8.213	0.004003	0.033	0.00	0.00
9	Solar Pilot Recovery Charge	8.213	0.000062	0.001	8.213	0.000062	0.001	0.00	0.00
10	Green Programs Recovery Charge	8.213	0.004920	0.040	8.213	0.004920	0.040	0.00	0.00
11	Tax Adjustment Credit	8.213	0.000000	0.000	8.213	0.000000	0.000	0.00	0.00
12	Green Enabling Mechanism	8.213	0.000000	0.000	8.213	0.000000	0.000	0.00	0.00
13	Facilities Chg.			0.000			0.000	0.00	0.00
14	Minimum			0.000			0.000	0.00	0.00
15	Miscellaneous			0.000			0.000	0.00	0.00
16	Delivery Subtotal	8.213		$0.255	8		$0.255	0.00	0.00
17	Unbilled Delivery			0.000			0.000	0.00	0.00
18	Delivery Subtotal w unbilled			$0.255			$0.255	0.00	0.00
19									
20	**Supply-BGS**								
21	BGS- June - September	1.895	0.065652	$0.124	1.895	0.065652	$0.124	$0.000	0.00
22	BGS- October - May	6.318	0.064594	0.408	6.318	0.064594	0.408	0.000	0.00
23	BGS Reconciliation-RSCP	8.213	(0.000352)	(0.003)	8.213	(0.000352)	(0.003)	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply subtotal	8.213		0.530	8.213		0.530	$0.000	0.00
26	Unbilled Supply			(0.003)			(0.003)	0.000	0.00
27	Supply subtotal w unbilled			$0.527			$0.527	$0.000	0.00
28									
29	Total Delivery + Supply	8.213		$0.782	8.213		$0.782	$0.000	0.00
30									
31									
32									
33	Notes:	Rates are annual averages derived from actual, excluding SUT.							
34		WHS revenues shown to 3 decimals							

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.129	0.63	$0.081	0.129	1.03	$0.133	$0.052	64.20
2	Distribution June - September	1.895	0.001925	0.004	1.895	0.001826	0.003	-0.001	-25.00
3	Distribution October - May	6.318	0.001925	0.012	6.318	0.001826	0.012	0.000	0.00
4	SBC	8.213	0.007767	0.064	8.213	0.007767	0.064	0.000	0.00
5	NGC	8.213	0.000024	0.000	8.213	0.000024	0.000	0.000	0.00
6	DAC	8.213	0.000000	0.000	8.213	0.000000	0.000	0.000	0.00
7	STC-MTC-Tax	8.213	0.000000	0.000	8.213	0.000000	0.000	0.000	0.00
8	ZECRC	8.213	0.004000	0.033	8.213	0.004000	0.033	0.000	0.00
9	Solar Pilot Recovery Charge	8.213	0.000063	0.001	8.213	0.000063	0.001	0.000	0.00
10	Green Programs Recovery Charge	8.213	0.004920	0.040	8.213	0.004920	0.040	0.000	0.00
11	Tax Adjustment Credit	8.213	0.000000	0.000	8.213	0.000000	0.000	0.000	0.00
12	Green Enabling Mechanism	8.213	0.000000	0.000	8.213	0.000000	0.000	0.000	0.00
13	Facilities Chg.			0.000			0.000	0.000	0.00
14	Minimum			0.000			0.000	0.000	0.00
15	Miscellaneous			0.000			0.000	0.000	0.00
16	Delivery Subtotal	8		$0.235	8		$0.286	$0.051	21.70
17	Unbilled Delivery			0.000			0.000	0.000	0.00
18	Delivery Subtotal w unbilled			$0.235			$0.286	$0.051	21.70
19									
20	**Supply-BGS**								
21	BGS- June - September	1.895	0.066429	$0.126	1.895	0.066429	$0.126	$0.000	0.00
22	BGS- October - May	6.318	0.066441	0.420	6.318	0.066441	0.420	0.000	0.00
23	BGS Reconciliation-RSCP	8.213	0.000000	0.000	8.213	0.000000	0.000	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply Subtotal	8.213		0.546	8.213		0.546	$0.000	0.00
26	Unbilled Supply			(0.003)			(0.003)	0.000	0.00
27	Supply Subtotal w unbilled			$0.543			$0.543	$0.000	0.00
28									
29	Total Delivery + Supply	8.213		$0.778	8.213		$0.829	$0.051	6.56
30									
31									
32									
33	Notes:	All customers assumed to be on BGS.							
34		WH, WHS & BPL-POF revenues shown to 3 decimals.							
35		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							
36									
37									
38									

RATE SCHEDULE HS
BUILDING HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	8.568	3.74	$32	8.568	3.74	$32	0.00	0.00
2	Distribution June - September	2,414	0.099458	240.053	2,391	0.099660	238.263	(1.79)	(0.75)
3	Distribution October - May	7,927	0.028887	228.987	7,960	0.028840	229.554	0.57	0.25
4	SBC	10,341	0.010190	105.371	10,350	0.010184	105.410	0.04	0.04
5	NGC	10,341	0.000011	0.113	10,350	0.000011	0.113	0.00	0.20
6	DAC	10,341	0.000000	0.000	10,350	0.000000	0.000	0.00	0.00
7	STC-MTC-Tax	10,341	0.000000	0.000	10,350	0.000000	0.000	0.00	0.00
8	ZECRC	10,341	0.004000	41.364	10,350	0.004000	41.403	0.04	0.09
9	Solar Pilot Recovery Charge	10,341	0.000062	0.643	10,350	0.000062	0.644	0.00	0.09
10	Green Programs Recovery Charge	10,341	0.004920	50.876	10,350	0.004920	50.924	0.05	0.09
11	Tax Adjustment Credit	10,341	(0.003758)	-38.860	10,350	(0.003758)	-38.898	(0.04)	0.10
12	Green Enabling Mechanism	10,341	0.000000	0	10,350	0.000000	0	0.00	0.00
13	Facilities Chg.			0			0	0.00	0.00
14	Minimum			0			0	0.00	0.00
15	Miscellaneous			0			0	0.00	(2.72)
16	Delivery Subtotal	10,341		$660	10,350		$659	(1.13)	(0.17)
17	Unbilled Delivery			2			16	13.53	653.92
18	Delivery Subtotal w unbilled			$663			$675	12.40	1.87
19									
20	**Supply-BGS**								
21	BGS- June - September	1,944	0.074996	$146	1,931	0.075001	$145	-$1	(0.68)
22	BGS- October - May	5,949	0.077613	462	5,969	0.077594	463	1	0.31
23	Transmission	7,893	0.047827	$377	7,899	0.047829	$378	$0	0.09
24	BGS Reconciliation-RSCP	7,893	(0.000053)	(0)	7,899	(0.000055)	(0)	(0)	3.18
25	BGS Miscellaneous			-0.027			-0.029	0.00	6.08
26	Supply subtotal	7,893		$985	7,899		$985	$1	0.08
27	Unbilled Supply			(8)			(1)	6	(81.55)
28	Supply subtotal w unbilled			$977			$984	$7	0.71
29									
30	Total Delivery + Supply	10,341		$1,639	10,350		$1,659	$19	1.18
31									
32									
33									
34									
35									
36									
37	Notes: Rates are annual averages derived from actual, excluding SUT.								

RATE SCHEDULE HS
BUILDING HEATING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	8.568	3.75	$32	8.568	6.10	$52	$20	62.50
2	Distribution June - September	2,391	0.098011	234	2,391	0.106660	255	21	8.97
3	Distribution October - May	7,960	0.029426	234	7,960	0.055908	445	211	90.17
4	SBC	10,350	0.007767	80	10,350	0.007767	80	0	0.00
5	NGC	10,350	0.000024	0	10,350	0.000024	0	0	0.00
6	DAC	10,350	0.000000	0	10,350	0.000000	0	0	0.00
7	STC-MTC-Tax	10,350	0.000000	0	10,350	0.000000	0	0	0.00
8	ZECRC	10,350	0.004000	41	10,350	0.004000	41	0	0.00
9	Solar Pilot Recovery Charge	10,350	0.000063	1	10,350	0.000063	1	0	0.00
10	Green Programs Recovery Charge	10,350	0.004920	51	10,350	0.004920	51	0	0.00
11	Tax Adjustment Credit	10,350	(0.001234)	-13	10,350	(0.001234)	-13	0	0.00
12	Green Enabling Mechanism	10,350	0.000000	0	10,350	0.000000	0	0	0.00
13	Facilities Chg.			0			0	0	0.00
14	Minimum			0			0	0	0.00
15	Miscellaneous			(0)			(0)	0	0.00
16	Delivery Subtotal	10,350		$660	10,350		$912	$252	38.19
17	Unbilled Delivery			16			22	6	37.50
18	Delivery Subtotal w unbilled			$676			$934	$258	38.17
19									
20	**Supply-BGS**								
21	BGS- June - September	2,391	0.075325	$180	2,391	0.075325	$180	$0	0.00
22	BGS- October - May	7,960	0.078509	625	7,960	0.078509	625	0	0.00
23	Transmission	10,350	0.047976	497	10,350	0.047976	497	0	0.00
24	BGS Reconciliation-RSCP	10,350	0.000000	0	10,350	0.000000	0	0	0.00
25	Miscellaneous			0			0	0	0.00
26	Supply Subtotal	10,350		$1,302	10,350		$1,302	$0	0.00
27	Unbilled Supply			(2)			(2)	0	0.00
28	Supply Subtotal w unbilled			$1,300			$1,300	$0	0.00
29									
30	Total Delivery + Supply	10,350		$1,976	10,350		$2,234	$258	13.06
31									
32									
33									
34	Notes:	All customers assumed to be on BGS.							
35		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							
36									
37									
38									
39									

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	3,275.054	4.81	$15,766	3,275.054	4.81	$15,766	0.00	0.00
2	Service Charge-unmetered	107.081	1.83	237	107.081	1.83	237	0.00	0.00
3	Service Charge-Night Use	0.722	347.77	251	0.722	347.77	251	0.00	0.00
4	Distrib. KW Annual	26,346	3.7507	98,819	26,280	3.7683	99,032	213.57	0.22
5	Distrib. KW June - September	9,772	9.4182	92,038	9,697	9.4182	91,327	(711.33)	(0.77)
6	Distribution kWhr, June-September	2,603,595	0.002983	7,767	2,583,201	0.002982	7,704	(62.63)	(0.81)
7	Distribution kWhr, October-May	4,476,412	0.007856	35,165	4,478,018	0.007855	35,177	12.31	0.04
8	Distribution kWhr, Night use, June-September	4,798	0.005559	27	4,755	0.005557	26	(0.25)	(0.95)
9	Distribution kWhr, Night use, October-May	18,050	0.007834	141	18,053	0.007833	141	0.02	0.02
10	SBC	7,102,855	0.009965	70,782	7,084,026	0.009965	70,595	(187.09)	(0.26)
11	NGC	7,102,855	0.000015	104	7,084,026	0.000015	103	(0.45)	(0.44)
12	DAC	7,102,855	0.000000	0	7,084,026	0.000000	0	0.00	0.00
13	STC-MTC-Tax	7,102,855	0.000000	0	7,084,026	0.000000	0	0.00	0.00
14	ZECRC	7,102,855	0.003999	28,402	7,084,026	0.003999	28,327	(75.26)	(0.26)
15	Solar Pilot Recovery Charge	7,102,855	0.000062	443	7,084,026	0.000062	442	(1.19)	(0.27)
16	Green Programs Recovery Charge	7,102,855	0.004920	34,946	7,084,026	0.004920	34,853	(92.64)	(0.27)
17	Tax Adjustment Credit	7,102,855	(0.001670)	-11,863	7,084,026	(0.001670)	-11,832	30.36	(0.26)
18	ECIP	26,346	1.183051	31,169	26,280	1.181059	31,038	(130.68)	(0.42)
19	Green Enabling Mechanism	7,102,855	0.000000	0	7,084,026	0.000000	0	0.00	0.00
20	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	1		$2.22/$3.20	2	0.00	0.03
21	Facilities Chg.		1.45%	24.81		1.45%	25	(0.12)	(0.49)
22	Minimum			13.39			13	(0)	(1.97)
23	Distrib. Miscellaneous			-1023.83			(1,019)	5	(0.48)
24	Delivery Subtotal	7,102,855		$403,210	7,084,026		$402,210	-$1,001	(0.25)
25	Unbilled Delivery			(556)			(1,163)	(607)	109.13
26	Delivery Subtotal w unbilled			$402,654			$401,047	-$1,608	(0.40)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	6,834	1.8023	$12,316	6,788	1.8071	$12,267	-$49	(0.40)
2	Generation Capacity Obl October-May	12,568	2.9804	37,458	12,573	2.9799	37,465	8	0.02
3	Transmission Capacity Obl	17,497	11.9916	209,815	17,460	11.9910	209,361	(454)	(0.22)
4	BGS kWhr June - September not night use	1,892,199	0.066990	126,759	1,877,715	0.066951	125,715	(1,044)	(0.82)
5	BGS kWhr October - May not night use	3,362,114	0.063829	214,602	3,363,254	0.063831	214,678	77	0.04
6	BGS kWhr June - September night use	3,358	0.062255	209	3,327	0.062238	207	(2)	(0.96)
7	BGS kWhr October - May night use	13,550	0.060072	814	13,552	0.060072	814	0	0.02
8	BGS Reconciliation-RSCP	5,271,221	(0.000277)	(1,460)	5,257,848	(0.000267)	(1,403)	57	(3.89)
9	BGS Miscellaneous			(81)			(81)	0	(0.54)
10	Supply subtotal	5,271,221		$600,432	5,257,848		$599,025	(1,408)	(0.23)
11	Unbilled Supply			(1,856)			-1,759	97	(5.21)
12	Supply Subtotal w Unbilled			$598,577			$597,266	(1,311)	(0.22)
13									
14	Total Delivery + Supply	7,102,855		$1,001,231	7,084,026		$998,312	($2,919)	(0.29)
15									
16									
17									
18									
19	Notes:	Rates are annual averages derived from actual, excluding SUT.							

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	3,275.054	4.78	$15,655	3,275.054	7.78	$25,480	$9,825	62.76
2	Service Charge-unmetered	107.081	2.20	236	107.081	3.58	383	147	62.29
3	Service Charge-Night Use	0.722	347.77	251	0.722	7.78	6	-245	-97.61
4	Distrib. KW Annual	26,280	3.7660	98,971	26,280	4.6357	121,827	22,856	23.09
5	Distrib. KW Summer	9,697	9.4441	91,578	9,697	15.3913	149,248	57,670	62.97
6	Distribution kWhr, June-September	2,583,201	0.003079	7,954	2,583,201	0.016508	42,643	34,689	436.12
7	Distribution kWhr, October-May	4,478,018	0.007858	35,188	4,478,018	0.003787	16,956	(18,232)	-51.81
8	Distribution kWhr, Night use, June-September	4,755	0.007858	37	4,755	0.003787	18	(19)	-51.35
9	Distribution kWhr, Night use, October-May	18,053	0.007858	142	18,053	0.003787	68	(74)	-52.11
10	SBC	7,084,026	0.007767	55,022	7,084,026	0.007767	55,022	0	0.00
11	NGC	7,084,026	0.000024	170	7,084,026	0.000024	170	0	0.00
12	DAC	7,084,026	0.000000	0	7,084,026	0.000000	0	0	0.00
13	STC-MTC-Tax	7,084,026	0.000000	0	7,084,026	0.000000	0	0	0.00
14	ZECRC	7,084,026	0.004000	28,336	7,084,026	0.004000	28,336	0	0.00
15	Solar Pilot Recovery Charge	7,084,026	0.000063	446	7,084,026	0.000063	446	0	0.00
16	Green Programs Recovery Charge	7,084,026	0.004920	34,853	7,084,026	0.004920	34,853	0	0.00
17	Tax Adjustment Credit	7,084,026	(0.000614)	-4,350	7,084,026	(0.000614)	-4,350	0	0.00
18	ECIP	26,280	1.2193	32,043	26,280	1.2193	32,043	0	0.00
19	Green Enabling Mechanism	7,084,026	0.000000	0	7,084,026	0.000000	0	0	0.00
20	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	2		$2.22/$3.20	2	0	0.00
21	Facilities Chg.		1.45%	25		1.45%	25	0	0.00
22	Minimum			13			13	0	0.00
23	Distrib. Miscellaneous			(1,019)			(1,017)	2	-0.20
24	Delivery Subtotal	7,084,026		$395,552	7,084,026		$502,171	$106,619	26.95
25	Unbilled Delivery			(1,144)			(1,452)	(308)	26.92
26	Delivery Subtotal w unbilled			$394,408			$500,719	$106,311	26.95

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	6,210	1.6327	$10,138	6,210	1.6327	$10,138	$0	0.00
2	Generation Capacity Obl October-May	12,398	1.6327	20,243	12,398	1.6327	20,243	0	0.00
3	Transmission Capacity Obl	16,660	12.4713	207,773	16,660	12.4713	207,773	0	0.00
4	BGS kWhr June - September not night use	2,583,201	0.067343	173,960	2,583,201	0.067343	173,960	0	0.00
5	BGS kWhr October - May not night use	4,478,018	0.067068	300,332	4,478,018	0.067068	300,332	0	0.00
6	BGS kWhr June - September night use	4,755	0.059237	282	4,755	0.059237	282	0	0.00
7	BGS kWhr October - May night use	18,053	0.063526	1,147	18,053	0.063526	1,147	0	0.00
8	BGS Reconciliation-RSCP	7,084,026	0.000000	0	7,084,026	0.000000	0	0	0.00
9	BGS Miscellaneous			(81)			(81)	0	0.00
10	Supply Subtotal	7,084,026		$713,794	7,084,026		$713,794	$0	0.00
11	Unbilled Supply			(2,096)			(2,096)	0	0.00
12	Supply Subtotal w unbilled			$711,698			$711,698	$0	0.00
13									
14	Total Delivery + Supply	7,084,026		$1,106,106	7,084,026		$1,212,417	$106,311	9.61
15									
16									
17									
18									
19	Notes:	All customers assumed to be on BGS.							
20		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	112.550	347.77	$39,142	112.550	347.77	$39,142	0.00	0.00
2	Distrib. KW Annual	25,488	3.7146	94,679	25,474	3.7138	94,605	(74.96)	(0.08)
3	Distrib. KW June - September	9,219	8.3212	76,713	9,172	8.3196	76,303	(410.35)	(0.53)
4	Distribution kWhr On Peak June-September	1,736,526	0.000000	0	1,726,736	0.000000	0	0.00	0.00
5	Distribution kWhr Off Peak June-September	1,872,589	0.000000	0	1,862,245	0.000000	0	0.00	0.00
6	Distribution kWhr On Peak October-May	3,306,817	0.000000	0	3,312,787	0.000000	0	0.00	0.00
7	Distribution kWhr Off Peak October-May	3,292,913	0.000000	0	3,299,199	0.000000	0	0.00	0.00
8	SBC	10,208,845	0.009976	101,844	10,200,967	0.009975	101,754	(89.98)	(0.09)
9	NGC	10,208,845	0.000014	146	10,200,967	0.000014	146	(0.19)	(0.13)
10	DAC	10,208,845	0.000000	0	10,200,967	0.000000	0	0.00	0.00
11	STC-MTC-Tax	10,208,845	0.000000	0	10,200,967	0.000000	0	0.00	0.00
12	ZECRC	10,208,845	0.004000	40,832	10,200,967	0.004000	40,800	(31.56)	(0.08)
13	Solar Pilot Recovery Charge	10,208,845	0.000062	637	10,200,967	0.000062	636	(0.50)	(0.08)
14	CIEP Standby Fee	2,956,091	0.000150	445	2,953,810	0.000150	444	(0.34)	(0.08)
15	Green Programs Recovery Charge	10,208,845	0.004920	50,228	10,200,967	0.004920	50,189	(38.76)	(0.08)
16	Tax Adjustment Credit	10,208,845	(0.000974)	(9,938)	10,200,967	(0.000974)	(9,933)	5.31	(0.05)
17	ECIP	25,488	1.007026	25,667	25,474	1.006341	25,635	(32.11)	(0.13)
18	Green Enabling Mechanism	10,208,845	0.000000	0	10,200,967	0.000000	0	0.00	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	55		$2.22/$3.20	55	(0.07)	(0.13)
20	Facilities Chg.		1.45%	118		1.45%	118	(0.10)	(0.08)
21	Minimum			0			0	0.00	0.00
22	Dist. Miscellaneous			(1,516)			(1,513)	3	(0.22)
23	Delivery Subtotal	10,208,845		$419,051	10,200,967		$418,381	(670)	(0.16)
24	Unbilled Delivery			1369			940	(429)	(31.36)
25	Delivery Subtotal w unbilled			$420,420			$419,321	-$1,100	(0.26)
26									
27									
28									
29									
30									
31									

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
	0-499								
1	Generation Capacity Obl - June-September	2,776	1.988400	$5,520	2,770	1.995100	$5,527	$7	0.12
2	Generation Capacity Obl - October-May	5,502	2.436900	13,408	5,507	2.436000	13,416	8	0.06
3	Transmission Capacity Obl	7,171	12.207100	87,534	7,170	12.205800	87,518	(16)	(0.02)
4	BGS kWhr June-September On Peak	995,323	0.039112	38,929	986,692	0.039273	38,751	(178)	(0.46)
5	BGS kWhr June-September Off Peak	570,003	0.063299	36,080	567,722	0.063276	35,923	(157)	(0.44)
6	BGS kWhr October-May On Peak	2,094,550	0.028611	59,928	2,096,520	0.028618	59,998	70	0.12
7	BGS kWhr October-May Off Peak	1,096,054	0.059090	64,766	1,097,057	0.059094	64,830	64	0.10
8	**500+**								
9	Generation Capacity Obl - June-September	561	9.797600	5,501	560	9.787800	5,483	(17)	(0.32)
10	Generation Capacity Obl - October-May	1,426	5.978200	8,522	1,427	5.981400	8,534	11	0.13
11	Transmission Capacity Obl	1,760	11.551000	20,335	1,760	11.549800	20,332	(3)	(0.01)
12	BGS kWhr June-September On Peak	258,582	0.025452	6,581	257,776	0.025411	6,550	(31)	(0.47)
13	Spare	0	0.000000	0	0	0.000000	0	0	0.00
14	BGS kWhr October-May On Peak	565,696	0.060802	34,395	566,163	0.060771	34,406	11	0.03
15	Spare	0	0.000000	0	0	0.000000	0	0	0.00
16									
17	BGS Reconciliation-RSCP	4,755,930	(0.000074)	(354)	4,747,990	(0.000068)	(323)	31	(8.74)
18	BGS Reconciliation-CIEP	824,278	0.000350	289	823,939	0.000322	265	(23)	(8.05)
19	BGS Miscellaneous	0		1,953	0		1,951	(2)	(0.11)
20	Supply subtotal	5,580,207		$383,387	5,571,930		$383,161	(226)	(0.06)
21	Unbilled Supply			(2,239)			(2,041)	198	(8.82)
22	Supply w Unbilled			$381,149			$381,120	(29)	(0.01)
23									
24	Total Delivery + Supply	10,208,845		$801,569	10,200,967		$800,441	($1,128)	(0.14)
25									
26									
27									
28	Notes: Rates are annual averages derived from actual, excluding SUT.								

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	112.550	347.77	$39,142	112.550	347.77	$39,142	$0	0.00
2	Distrib. KW Annual	25,474	3.6224	92,276	25,474	3.7808	96,311	4,035	4.37
3	Distrib. KW June - September	9,172	8.6179	79,039	9,172	12.9480	118,753	39,714	50.25
4	Distribution kWhr On Peak June-September	1,726,736	0.000000	0	1,726,736	0.000000	0	0	0.00
5	Distribution kWhr Off Peak June-September	1,862,245	0.000000	0	1,862,245	0.000000	0	0	0.00
6	Distribution kWhr On Peak October-May	3,312,787	0.000000	0	3,312,787	0.000000	0	0	0.00
7	Distribution kWhr Off Peak October-May	3,299,199	0.000000	0	3,299,199	0.000000	0	0	0.00
8	SBC	10,200,967	0.007767	79,231	10,200,967	0.007767	79,231	0	0.00
9	NGC	10,200,967	0.000024	245	10,200,967	0.000024	245	0	0.00
10	DAC	10,200,967	0.000000	0	10,200,967	0.000000	0	0	0.00
11	STC-MTC-Tax	10,200,967	0.000000	0	10,200,967	0.000000	0	0	0.00
12	ZECRC	10,200,967	0.004000	40,804	10,200,967	0.004000	40,804	0	0.00
13	Solar Pilot Recovery Charge	10,200,967	0.000063	643	10,200,967	0.000063	643	0	0.00
14	CIEP Standby Fee	2,953,810	0.000150	443	2,953,810	0.000150	443	0	0.00
15	Green Programs Recovery Charge	10,200,967	0.004920	50,189	10,200,967	0.004920	50,189	0	0.00
16	Tax Adjustment Credit	10,200,967	(0.000347)	-3,540	10,200,967	(0.000347)	-3,540	0	0.00
17	ECIP	25,474	1.029000	26,213	25,474	1.029000	26,213	0	0.00
17	Green Enabling Mechanism	10,200,967	0.000000	0	10,200,967	0.000000	0	0	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	55		$2.22/$3.20	55	0	0.00
19	Facilities Chg.		1.45%	118		1.45%	118	0	0.00
20	Minimum			0			0	0	0.00
21	Dist. Miscellaneous			(1,513)			(1,512)	1	-0.07
22	Delivery Subtotal	10,200,967		$403,346	10,200,967		$447,096	$43,750	10.85
23	Unbilled Delivery			906			1,004	98	10.82
24	Delivery Subtotal w unbilled			$404,252			$448,100	$43,848	10.85

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	0-499								
1	Generation Capacity Obl - June-September	2,772	1.6327	$4,525	2,772	1.6327	$4,525	$0	0.00
2	Generation Capacity Obl - October-May	5,514	1.6327	9,003	5,514	1.6327	9,003	0	0.00
3	Transmission Capacity Obl	7,116	12.4713	88,745	7,116	12.4713	88,745	0	0.00
4	BGS kWhr June-September On Peak	1,365,643	0.075223	102,728	1,365,643	0.075223	102,728	0	0.00
5	BGS kWhr June-September Off Peak	1,472,814	0.059237	87,245	1,472,814	0.059237	87,245	0	0.00
6	BGS kWhr October-May On Peak	2,620,021	0.070936	185,854	2,620,021	0.070936	185,854	0	0.00
7	BGS kWhr October-May Off Peak	2,609,274	0.063526	165,757	2,609,274	0.063526	165,757	0	0.00
8	**500+**								
9	Generation Capacity Obl - June-September	732	10.0663	7,365	732	10.0663	7,365	0	0.00
10	Generation Capacity Obl - October-May	1,459	10.0663	14,689	1,459	10.0663	14,689	0	0.00
11	Transmission Capacity Obl	1,918	12.4713	23,916	1,918	12.4713	23,916	0	0.00
12	BGS kWhr June-September	750,524	0.094382	70,836	750,524	0.094382	70,836	0	0.00
13	Spare	0	0.094382	0	0	0.094382	0	0	0.00
14	BGS kWhr October-May	1,382,692	0.076107	105,233	1,382,692	0.076107	105,233	0	0.00
15	Spare	0	0.076107	0	0	0.076107	0	0	0.00
16									
17	BGS Reconciliation-RSCP	8,067,752	0.000000	0	8,067,752	0.000000	0	0	0.00
18	BGS Reconciliation-CIEP	2,133,216	0.000000	0	2,133,216	0.000000	0	0	0.00
19	BGS Miscellaneous			1,951			1,951	0	0.00
20	Supply Subtotal	10,200,968		$867,847	10,200,968		$867,847	$0	0.00
21	Unbilled Supply			(4,623)			(4,623)	0	0.00
22	Supply Subtotal w unbilled			$863,224			$863,224	$0	0.00
23									
24	Total Delivery + Supply	10,200,967		$1,267,476	10,200,967		$1,311,324	$43,848	3.46
25									
26									
27									
28									
29	Notes:	All customers assumed to be on BGS.							
30		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	9.239	347.90	$3,214	9.239	347.90	$3,214	0.00	0.00
2	Service Charge-Alternate	0.127	81.56	10	0.127	81.56	10	0.00	0.00
3	Distrib. KW Annual	6,546	2.4826	16251	6,546	2.4826	16251	0.00	0.00
4	Distrib. KW June - September	2,456	7.2967	17918	2,456	7.2967	17918	0.00	0.00
5	Distribution kWhr On Peak June-September	500,122	0.000000	0	500,122	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak June-September	610,161	0.000000	0	610,161	0.000000	0	0.00	0.00
7	Distribution kWhr On Peak October-May	867,288	0.000000	0	867,288	0.000000	0	0.00	0.00
8	Distribution kWhr Off Peak October-May	967,215	0.000000	0	967,215	0.000000	0	0.00	0.00
9	SBC	2,944,785	0.009776	28787	2,944,785	0.009776	28787	0.00	0.00
10	NGC	2,944,785	0.000015	44	2,944,785	0.000015	44	0.00	0.00
11	DAC	2,944,785	0.000000	0	2,944,785	0.000000	0	0.00	0.00
12	STC-MTC-Tax	2,944,785	0.000000	0	2,944,785	0.000000	0	0.00	0.00
13	ZECRC	2,944,785	0.004000	11778	2,944,785	0.004000	11778	0.00	0.00
14	Solar Pilot Recovery Charge	2,944,785	0.000062	184	2,944,785	0.000062	184	0.00	0.00
15	CIEP Standby Fee	2,944,785	0.000000	0	2,944,785	0.000000	0	0.00	0.00
16	Green Programs Recovery Charge	2,944,785	0.004920	14488	2,944,785	0.004920	14488	0.00	0.00
17	Tax Adjustment Credit	2,944,785	(0.000621)	(1830)	2,944,785	(0.000621)	(1830)	0.00	0.00
18	Green Enabling Mechanism	2,944,785	0.000000	0	2,944,785	0.000000	0	0.00	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	245		$2.22/$3.20	245	0.00	0.00
20	Facilities Chg.		1.45%	185		1.45%	185	0.00	0.00
21	Minimum			0			0	0	0.00
22	Dist. Miscellaneous			2			2	0	0.00
23	Delivery Subtotal	2,944,785		$91,277	2,944,785		$91,277	$0	0.00
24	Unbilled Delivery			(644)			(644)	0	0.00
25	Delivery Subtotal w unbilled			$90,633			$90,633	$0	0.00
26									
27									
28									
29									
30									
31									

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	485	9.7764	$4,743	485	9.7764	$4,743	$0	0.00
2	Generation Capacity Obl October-May	1,050	8.5845	9,012	1050	8.5845	9,012	0	0.00
3	Transmission Capacity Obl	1,354	11.9801	16,215	1354	11.9801	16,215	0	0.00
4	BGS kWhr June-September On Peak	116,282	0.085698	9,965	116282	0.085698	9,965	0	0.00
5	BGS kWhr June-September Off Peak	123,903	0.000000	5,116	123903	0.000000	5,116	0	0.00
6	BGS kWhr October-May On Peak	219,498	0.062844	13,794	219498	0.062844	13,794	0	0.00
7	BGS kWhr October-May Off Peak	240,813	0.000000	11,156	240813	0.000000	11,156	0	0.00
8	BGS Reconciliation-CIEP	700,496	0.000589	413	700496	0.000589	413	0	0.00
9	BGS Miscellaneous			-9,578			-9,578	0	0.00
10	Supply subtotal	700,496		$60,837	700,496		$60,837	0	0.00
11	Unbilled Supply			24			24	(0)	0.00
12	Supply w Unbilled			$60,861			$60,861	0	0.00
13									
14	Total Delivery + Supply	2,944,785		$151,494	2,944,785		$151,494	$0	0.00

Notes: Rates are annual averages derived from actual, excluding SUT.

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	9.239	347.77	$3,213	9.239	347.77	$3,213	$0	0.00
2	Service Charge-Alternate	0.127	21.58	3	0.127	35.12	4	1	33.33
3	Distrib. KW Annual	6,546	1.6885	11,053	6,546	2.9510	19,317	8,264	74.77
4	Distrib. KW June - September	2,456	9.3731	23,017	2,456	13.2370	32,505	9,488	41.22
5	Distribution kWhr On Peak June-September	500,122	0.000000	0	500,122	0.000000	0	0	0.00
6	Distribution kWhr Off Peak June-September	610,161	0.000000	0	610,161	0.000000	0	0	0.00
7	Distribution kWhr On Peak October-May	867,288	0.000000	0	867,288	0.000000	0	0	0.00
8	Distribution kWhr Off Peak October-May	967,215	0.000000	0	967,215	0.000000	0	0	0.00
9	SBC	2,944,785	0.007615	22,425	2,944,785	0.007615	22,425	0	0.00
10	NGC	2,944,785	0.000024	71	2,944,785	0.000024	71	0	0.00
11	DAC	2,944,785	0.000000	0	2,944,785	0.000000	0	0	0.00
12	STC-MTC-Tax	2,944,785	0.000000	0	2,944,785	0.000000	0	0	0.00
13	ZECRC	2,944,785	0.004000	11,779	2,944,785	0.004000	11,779	0	0.00
14	Solar Pilot Recovery Charge	2,944,785	0.000063	186	2,944,785	0.000063	186	0	0.00
15	CIEP Standby Fee	2,944,785	0.000150	442	2,944,785	0.000150	442	0	0.00
16	Green Programs Recovery Charge	2,944,785	0.004920	14,488	2,944,785	0.004920	14,488	0	0.00
17	Tax Adjustment Credit	2,944,785	(0.000222)	-654	2,944,785	(0.000222)	-654	0	0.00
18	Green Enabling Mechanism	2,944,785	0.000000	0	2,944,785	0.000000	0	0	0.00
19	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	245		$2.22/$3.20	245	0	0.00
20	Facilities Chg.		1.45%	185		1.45%	185	0	0.00
21	Minimum			0			0	0	0.00
22	Dist. Miscellaneous			2			2	0	0.00
23	Delivery Subtotal	2,944,785		$86,455	2,944,785		$104,208	$17,753	20.53
24	Unbilled Delivery			(610)			(735)	(125)	20.49
25	Delivery Subtotal w unbilled			$85,845			$103,473	$17,628	20.53

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	538	10.0663	$5,411	538	10.0663	$5,411	$0	0.00
2	Generation Capacity Obl October-May	1,054	10.0663	10,613	1,054	10.0663	10,613	0	0.00
3	Transmission Capacity Obl	1,408	12.4713	17,557	1,408	12.4713	17,557	0	0.00
4	BGS kWhr June-September On Peak	500,122	0.089014	44,518	500,122	0.089014	44,518	0	0.00
5	BGS kWhr June-September Off Peak	610,161	0.089014	54,313	610,161	0.089014	54,313	0	0.00
6	BGS kWhr October-May On Peak	867,288	0.072390	62,783	867,288	0.072390	62,783	0	0.00
7	BGS kWhr October-May Off Peak	967,215	0.072390	70,017	967,215	0.072390	70,017	0	0.00
8	BGS Reconciliation-CIEP	2,944,785	0.000000	0	2,944,785	0.000000	0	0	0.00
9	BGS Miscellaneous			-9,578			-9,578	0	0.00
10	Supply Subtotal	2,944,785		$255,634	2,944,785		$255,634	$0	0.00
11	Unbilled Supply			100			100	0	0.00
12	Supply Subtotal w unbilled			$255,734			$255,734	$0	0.00
13									
14	Total Delivery + Supply	2,944,785		$341,578	2,944,785		$359,206	$17,628	5.16

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.273	1,911.39	$4,344	2.273	1,911.39	$4,344	0.00	0.00
2	Distrib. KW Annual	11,771	1.1431	13,455	11,771	1.1431	13,455	0.00	0.00
3	Distrib. KW June - September	3,240	4.0812	13,223	3,240	4.0812	13,223	0.00	0.00
4	Distribution kWhr On Peak	2,062,613	0.000000	0	2,062,613	0.000000	0	0.00	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak	2,478,938	0.000000	0	2,478,938	0.000000	0	0.00	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
8	SBC	4,541,551	0.009721	44,149	4,541,551	0.009721	44,149	0.00	0.00
9	NGC	4,541,551	0.000014	64	4,541,551	0.000014	64	0.00	0.00
10	DAC	4,541,551	0.000000	0	4,541,551	0.000000	0	0.00	0.00
11	STC-MTC-Tax	4,541,551	0.000000	0	4,541,551	0.000000	0	0.00	0.00
12	ZECRC	4,541,551	0.004000	18,166	4,541,551	0.004000	18,166	0.00	0.00
13	Solar Pilot Recovery Charge	4,541,551	0.000062	283	4,541,551	0.000014	64	(219.30)	-77.41
14	CIEP Standby Fee	4,541,551	0.000000	0	4,541,551	0.000000	0	0.00	0.00
15	Green Programs Recovery Charge	4,541,551	0.004920	22,344	4,541,551	0.004920	22,344	0.00	0.00
16	Tax Adjustment Credit	4,541,551	(0.000584)	-2,652	4,541,551	(0.000584)	-2,652	0.00	0.00
17	Green Enabling Mechanism	4,541,551	0.000000	0	4,541,551	0.000000	0	0.00	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$1.83/$2.20	41		$1.83/$2.20	41	0.00	0.00
19	Facilities Chg.		1.45%	119		1.45%	119	0.00	0.00
20	Minimum			0			0	0.00	0.00
21	Dist. Miscellaneous			138			138	0	0.00
22	Delivery Subtotal	4,541,551		$113,675	4,541,551		$113,456	-$219	-0.19
23	Unbilled Delivery			(1,596)			(1,376)	219	-13.74
24	Delivery Subtotal w unbilled			$112,079			$112,079	$0	0.00
25									
26									
27									
28									
29									
30									

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	493	9.7165	$4,794	493	9.7165	$4,794	$0	0.00
2	Generation Capacity Obl October-May	947	8.5989	8,146	947	8.5989	8,146	0	0.00
3	Transmission Capacity Obl	1,258	12.0044	15,104	1,258	12.0044	15,104	0	0.00
4	BGS kWhr June-September	304,415	0.023766	7,235	304,415	0.023766	7,235	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	BGS kWhr October-May	548,841	0.048049	26,371	548,841	0.048049	26,371	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	BGS Reconciliation-CIEP	853,255	0.000168	144	853,255	0.000168	144	0	0.00
9	BGS Miscellaneous			2,271			2,271	0	0.00
10	Supply subtotal	853,255		$64,065	853,255		$64,065	$0	0.00
11	Unbilled Supply			548			548	0	0.00
12	Supply w Unbilled			$64,612			$64,612	$0	0.00
13									
14	Total Delivery + Supply	4,541,551		$176,692	4,541,551		$176,692	$0	0.00
15									
16									
17									
18	Notes:	Rates are annual averages derived from actual, excluding SUT.							

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.273	1,911.39	$4,344	2.273	1,911.39	$4,344	$0	0.00
2	Distrib. KW Annual	11,771	1.1442	13,468	11,771	1.8460	21,729	8,261	61.34
3	Distrib. KW June - September	3,240	4.1361	13,401	3,240	6.6731	21,621	8,220	61.34
4	Distribution kWhr On Peak	2,062,613	0.000000	0	2,062,613	0.000000	0	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution kWhr Off Peak	2,478,938	0.000000	0	2,478,938	0.000000	0	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	SBC	4,541,551	0.007542	34,252	4,541,551	0.007542	34,252	0	0.00
9	NGC	4,541,551	0.000023	104	4,541,551	0.000023	104	0	0.00
10	DAC	4,541,551	0.000000	0	4,541,551	0.000000	0	0	0.00
11	STC-MTC-Tax	4,541,551	0.000000	0	4,541,551	0.000000	0	0	0.00
12	ZECRC	4,541,551	0.004000	18,166	4,541,551	0.004000	18,166	0	0.00
13	Solar Pilot Recovery Charge	4,541,551	0.000063	286	4,541,551	0.000063	286	0	0.00
14	CIEP Standby Fee	4,541,551	0.000150	681	4,541,551	0.000150	681	0	0.00
15	Green Programs Recovery Charge	4,541,551	0.004920	22,344	4,541,551	0.004920	22,344	0	0.00
16	Tax Adjustment Credit	4,541,551	(0.000205)	-931	4,541,551	(0.000205)	-931	0	0.00
17	Green Enabling Mechanism	4,541,551	0.000000	0	4,541,551	0.000000	0	0	0.00
18	Duplicate Svc (Same Sub/Different Sub)		$1.83/$2.20	41		$1.83/$2.20	41	0	0.00
19	Facilities Chg.		1.45%	119		1.45%	119	0	0.00
20	Minimum			0			0	0	0.00
21	Dist. Miscellaneous			138			138	0	0.00
22	Delivery Subtotal	4,541,551		$106,413	4,541,551		$122,894	$16,481	15.49
23	Unbilled Delivery			(1,291)			(1,491)	(200)	15.49
24	Delivery Subtotal w unbilled			$105,122			$121,403	$16,281	15.49

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	491	10.0663	$4,939	491	10.0663	$4,939	$0	0.00
2	Generation Capacity Obl October-May	961	10.0663	9,669	961	10.0663	9,669	0	0.00
3	Transmission Capacity Obl	1,272	12.4713	15,860	1,272	12.4713	15,860	0	0.00
4	BGS kWhr June-September On	759,223	0.086107	65,374	759,223	0.086107	65,374	0	0.00
5	BGS kWhr June-September Off	900,166	0.086107	77,511	900,166	0.086107	77,511	0	0.00
6	BGS kWhr October-May On	1,303,390	0.069347	90,386	1,303,390	0.069347	90,386	0	0.00
7	BGS kWhr October-May Off	1,578,772	0.069347	109,483	1,578,772	0.069347	109,483	0	0.00
8	BGS Reconciliation-CIEP	4,541,551	0.000000	0	4,541,551	0.000000	0	0	0.00
9	BGS Miscellaneous			2,271			2,271	0	0.00
10	Supply Subtotal	4,541,551		$375,493	4,541,551		$375,493	$0	0.00
11	Unbilled Supply			3,210			3,210	0	0.00
12	Supply Subtotal w unbilled			$378,703			$378,703	$0	0.00
13									
14	Total Delivery + Supply	4,541,551		$483,825	4,541,551		$500,106	$16,281	3.37
15									
16									
17									
18									
19	Notes:	All customers assumed to be on BGS.							
20		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.196	1,720.25	$337	0.196	1,720.25	$337	0.00	0.00
2	Distrib. KW Annual	3,165	0.6599	2,089	3,165	0.6599	2,089	0.00	0.00
3	Distrib. KW June - September	0	0.0000	0	0	0.0000	0	0.00	0.00
4	Distribution kWhr On Peak	197,731	0.000000	0	197,731	0.000000	0	0.00	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
6	Distribution kWhr Off Peak	238,260	0.000000	0	238,260	0.000000	0	0.00	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0.00	0.00
8	SBC	435,991	0.009751	4,251	435,991	0.009751	4,251	0.00	0.00
9	NGC	435,991	0.000012	5	435,991	0.000012	5	0.00	0.00
10	DAC	435,991	0.000000	0	435,991	0.000000	0	0.00	0.00
11	STC-MTC-Tax	435,991	0.000000	0	435,991	0.000000	0	0.00	0.00
12	ZECRC	435,991	0.004000	1,744	435,991	0.004000	1,744	0.00	0.00
13	Solar Pilot Recovery Charge	435,991	0.000062	27	435,991	0.000012	5	(21.73)	-80.02
14	CIEP Standby Fee	435,991	0.000000	0	435,991	0.000000	0	0.00	0.00
15	Green Programs Recovery Charge	435,991	0.004920	2,145	435,991	0.004920	2,145	0.00	0.00
16	Tax Adjustment Credit	435,991	(0.000210)	-92	435,991	(0.000210)	-92	0.00	0.00
17	Green Enabling Mechanism	435,991	0.000000	0	435,991	0.000000	0	0.00	0.00
18	Facilities Chg.			16			16	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Dist. Miscellaneous			(28)			(28)	0.00	0.00
21	Delivery Subtotal	435,991		$10,494	435,991		$10,473	-$22	-0.21
22	Unbilled Delivery			468			490	22	4.64
23	Delivery Subtotal w unbilled			$10,962			$10,962	$0	0.00

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
	Supply-BGS								
1	Generation Capacity Obl June-September	0.956	10.0352	$10	0.956	10.0352	$10	$0	0.00
2	Generation Capacity Obl October-May	5	8.4945	45	5	8.4945	45	0	0.00
3	Transmission Capacity Obl	6	11.8276	67	6	11.8276	67	0	0.00
4	BGS kWhr June-September	16,311	0.023675	386	16,311	0.023675	386	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	BGS kWhr October-May	7,839	0.038237	300	7,839	0.038237	300	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	BGS Reconciliation-CIEP	24,149	(0.000544)	(13)	24,149	(0.000544)	(13)	0	0.00
9	BGS Miscellaneous			121	0		121	0	0.00
10	Supply subtotal	24,149		$916	24,149		$916	$0	0.00
11	Unbilled Supply			(737)			(737)	0	0.00
12	Supply w Unbilled			$179			$179	$0	0.00
13									
14	Total Delivery + Supply	435,991		$11,141	435,991		$11,141	$0	0.00
15									
16									
17									
18	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.196	1,720.25	$337	0.196	1,720.25	$337	$0	0.00
2	Distrib. KW Annual	3,165	0.6322	2,001	3,165	0.7861	2,488	487	24.34
3	Distrib. KW June - September	0	0.0000	0	0	0.0000	0	0	0.00
4	Distribution kWhr On Peak	197,731	0.000000	0	197,731	0.000000	0	0	0.00
5	Spare	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution kWhr Off Peak	238,260	0.000000	0	238,260	0.000000	0	0	0.00
7	Spare	0	0.000000	0	0	0.000000	0	0	0.00
8	SBC	435,991	0.007475	3,259	435,991	0.007475	3,259	0	0.00
9	NGC	435,991	0.000023	10	435,991	0.000023	10	0	0.00
10	DAC	435,991	0.000000	0	435,991	0.000000	0	0	0.00
11	STC-MTC-Tax	435,991	0.000000	0	435,991	0.000000	0	0	0.00
12	ZECRC	435,991	0.004000	1,744	435,991	0.004000	1,744	0	0.00
13	Solar Pilot Recovery Charge	435,991	0.000063	27	435,991	0.000063	27	0	0.00
14	CIEP Standby Fee	435,991	0.000150	65	435,991	0.000150	65	0	0.00
15	Green Programs Recovery Charge	435,991	0.004920	2,145	435,991	0.004920	2,145	0	0.00
16	Tax Adjustment Credit	435,991	(0.000080)	-35	435,991	(0.000080)	-35	0	0.00
17	Green Enabling Mechanism	435,991	0.000000	0	435,991	0.000000	0	0	0.00
18	Facilities Chg.			16			16	0	0.00
19	Minimum			0			0	0	0.00
20	Dist. Miscellaneous			(28)			(28)	0	0.00
21	Delivery Subtotal	435,991		$9,541	435,991		$10,028	$487	5.10
22	Unbilled Delivery			446			469	23	5.16
23	Delivery Subtotal w unbilled			$9,987			$10,497	$510	5.11

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Generation Capacity Obl June-September	3	10.0663	$29	3	10.0663	$29	$0	0.00
2	Generation Capacity Obl October-May	6	10.0663	57	6	10.0663	57	0	0.00
3	Transmission Capacity Obl	7	12.4713	90	7	12.4713	90	0	0.00
4	BGS kWhr June-September On	57,478	0.084959	4,883	57,478	0.084959	4,883	0	0.00
5	BGS kWhr June-September Off	68,126	0.084959	5,788	68,126	0.084959	5,788	0	0.00
6	BGS kWhr October-May On	140,253	0.052881	7,417	140,253	0.052881	7,417	0	0.00
7	BGS kWhr October-May Off	170,133	0.052881	8,997	170,133	0.052881	8,997	0	0.00
8	BGS Reconciliation-CIEP	435,991	0.000000	0	435,991	0.000000	0	0	0.00
9	BGS Miscellaneous			121			121	0	0.00
10	Supply Subtotal	435,991		$27,382	435,991		$27,382	$0	0.00
11	Unbilled Supply			0			0	0	0.00
12	Supply Subtotal w unbilled			$27,382			$27,382	$0	0.00
13									
14	Total Delivery + Supply	435,991		$37,369	435,991		$37,879	$510	1.36
15									
16	Notes:	All customers assumed to be on BGS.							
17		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	2,220.312	0	$25,039	2,220.312	0	$25,039	0.00	0.00
2	Metal Halide	285.516	0	6,441	285.516	0	6,441	0.00	0.00
3	Filament/Incandescent	142.200	0	542	142.200	0	542	0.00	0.00
4	Mercury Vapor	312.204	0	2,329	312.204	0	2,329	0.00	0.00
5	Induction	1,320.456	0	11,835	1,320.456	0	11,835	0.00	0.00
6	LED	248.520	0	5,138	248.520	0	5,138	0.00	0.00
7									
8	Distribution June-September	75,127	0.007119	$570	75,127	0.007119	$570	0.00	0.00
9	Distribution October-May	210,786	0.007119	1,465	210,786	0.007119	1,465	0.00	0.00
10	SBC	285,913	0.009995	2,858	285,913	0.009995	2,858	0.00	0.00
11	NGC	285,913	0.000056	16	285,913	0.000056	16	0.00	0.00
12	ZECRC	285,913	0.004001	1,144	285,913	0.004001	1,144	0.00	0.00
13	Solar Pilot Recovery Charge	285,913	0.000062	18	285,913	0.000062	18	0.00	0.00
14	Green Programs Recovery Charge	285,913	0.004920	1,407	285,913	0.004920	1,407	0.00	0.00
15	Tax Adjustment Credit	285,913	0.000000	0	285,913	0.000000	0	0.00	0.00
16	ECIP	285,913	0.000000	0	285,913	0.000000	0	0.00	0.00
17									
18	Pole Charges	497.880		2,492	497.880		2,492	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Miscellaneous			703			703	0	0.00
21	Delivery Subtotal	285,913		$61,998	285,913		$61,998	$0	0.00
22	Unbilled Delivery			0			0	0	0.00
23	Delivery Subtotal w unbilled			$61,998			$61,998	$0	0.00
24									
25	**Supply-BGS**								
26	BGS June-September	61,732	0.060525	3,736	61,732	0.060525	3,736	0	0.00
27	BGS October-May	206,107	0.061974	12,773	206,107	0.061974	12,773	0	0.00
28	BGS Reconciliation-RSCP	267,840	0.001338	358	267,840	0.001338	358	0	0.00
29	Miscellaneous			(0)			(0)	0	0.00
30	Supply subtotal	267,840		$16,868	267,840		$16,868	$0	0.00
31	Unbilled Supply			0			0	0	0.00
32	Supply subtotal w unbilled			$16,868			$16,868	$0	0.00
33									
34	Total Delivery + Supply	285,913		$78,865	285,913		$78,865	$0	0.00
35									
36	Notes:	Rates are annual averages derived from actual, excluding SUT.							
37									

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	2,220.312	0	$ 26,640	2,220.312	0	$ 28,543	$1,903	7.14
2	Metal Halide	285.516	0	6,214	285.516	0	6,520	306	4.92
3	Filament/Incandescent	142.200	0	618	142.200	0	1,011	393	63.59
4	Mercury Vapor	312.204	0	2,607	312.204	0	3,441	834	31.99
5	Induction	1,320.456	0	12,882	1,320.456	0	14,707	1,825	14.17
6	LED	248.520	0	3,768	248.520	0	4,018	250	6.63
7									
8	Distribution June-September	75,127	0.006894	$518	75,127	0.008160	$613	95	18.34
9	Distribution October-May	210,786	0.006894	1,453	210,786	0.008160	1,720	267	18.38
10	SBC	285,913	0.007767	2,221	285,913	0.007767	2,221	0	0.00
11	NGC	285,913	0.000024	7	285,913	0.000024	7	0	0.00
12	ZECRC	285,913	0.004000	1,144	285,913	0.004000	1,144	0	0.00
13	Solar Pilot Recovery Charge	285,913	0.000063	18	285,913	0.000063	18	0	0.00
14	Green Programs Recovery Charge	285,913	0.004920	1,407	285,913	0.004920	1,407	0	0.00
15	Tax Adjustment Credit	285,913	0.000000	0	285,913	0.000000	0	0	0.00
16	ECIP	285,913	0.000000	0	285,913	0.000000	0	0	0.00
17									
18	Pole Charges	497.880		2,678	497.880		2,778	100	3.73
19	Minimum			0			0	0	0.00
20	Miscellaneous			703			703	(0)	0.00
21	Delivery Subtotal			$62,878			$68,851	$5,973	9.50
22	Unbilled Delivery			0			0	0	0.00
23	Delivery Subtotal w unbilled			$62,878			$68,851	$5,973	9.50
24									
25	**Supply-BGS**								
26	BGS June-September	75,127	0.061239	4,601	75,127	0.061239	4,601	0	0.00
27	BGS October-May	210,786	0.066509	14,019	210,786	0.066509	14,019	0	0.00
28	BGS Reconciliation-RSCP	285,913	0.000000	0	285,913	0.000000	0	0	0.00
29	Miscellaneous			(0)			(0)	0	0.00
30	Supply Subtotal			$18,620			$18,620	$0	0.00
31	Unbilled Supply			0			0	0	0.00
32	Supply Subtotal w unbilled			$18,620			$18,620	$0	0.00
33									
34	Total Delivery + Supply	285,913		$81,498	285,913		$87,471	$5,973	7.33
35									
36	Notes:	All customers assumed to be on BGS.							
37		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE-POF
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	124.548	0	$180	124.548	0	$180	0.00	0.00
2	Metal Halide	1.476	0	5	1.476	0	5	0.00	0.00
3	Filament	6.048	0	22	6.048	0	22	0.00	0.00
4	Mercury Vapor	4.140	0	4	4.140	0	4	0.00	0.00
5	Fluorescent	0.024	0	0	0.024	0	0	0.00	0.00
6	Induction	0.000	0	0	0.000	0	0	0.00	0.00
7	LED	0.000	0	0	0.000	0	0	0.00	0.00
8									
9	Distribution June-September	3,632	0.006790	$27	3,632	0.006790	$27	0.00	0.00
10	Distribution October-May	10,661	0.006790	70	10,661	0.006790	$70	0.00	0.00
11	SBC	14,294	0.009973	143	14,294	0.009973	$143	0.00	0.00
12	NGC	14,294	0.000055	1	14,294	0.000055	$1	0.00	0.00
13	ZECRC	14,294	0.004003	57	14,294	0.004003	$57	0.00	0.00
14	Solar Pilot Recovery Charge	14,294	0.000062	1	14,294	0.000062	$1	0.00	0.00
15	Green Programs Recovery Charge	14,294	0.004920	70	14,294	0.004920	$70	0.00	0.00
16	Tax Adjustment Credit	14,294	(0.001433)	-20	14,294	(0.001433)	-$20	0.00	0.00
17	ECIP	14,294	0.000000	0	14,294	0.000000	$0	0.00	0.00
18									
19	Pole Charges	0.000		0	0.000		0	0.00	0.00
20	Minimum			0			0	0.00	0.00
21	Miscellaneous			13			13	0	0.00
22	Delivery Subtotal	14,294		$573	14,294		$573	$0	0.00
23	Unbilled Delivery			0			0	0	0.00
24	Delivery Subtotal w unbilled			$573			$573	$0	0.00
25									
26	**Supply-BGS**								
27	BGS June-September	3,513	0.061231	215	3,513	0.061231	215	0	0.00
28	BGS October-May	10,612	0.060569	643	10,612	0.060569	643	0	0.00
29	BGS Reconciliation-RSCP	14,125	(0.001168)	(16)	14,125	(0.001168)	(16)	0	0.00
30	Miscellaneous			0			0	0	0.00
31	Supply subtotal	14,125		$841	14,125		$841	$0	0.00
32	Unbilled Supply			0			0	0	0.00
33	Supply subtotal w unbilled			$841			$841	$0	0.00
34									
35	Total Delivery + Supply	14,294		$1,414	14,294		$1,414	$0	0.00
36									
37	Notes:	Rates are annual averages derived from actual, excluding SUT.							

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	124.548	0	$ 233.224	124.548	0	$ 282.905	$49.681	21.30
2	Metal Halide	1.476	0	$ 6.066	1.476	0	$ 7.253	$1.187	19.57
3	Filament	6.048	0	$ 31.739	6.048	0	$ 39.239	$7.500	23.63
4	Mercury Vapor	4.140	0	$ 2.848	4.140	0	$ 3.675	$0.827	29.04
5	Fluorescent	0.024	0	$ -	0.024	0	$ -	$0.000	0.00
6	Induction	0.000	0	$ -	0.000	0	$ -	$0.000	0.00
7	LED	0.000	0	$ -	0.000	0	$ -	$0.000	0.00
8									
9	Distribution June-September	3,632	0.006931	$ 25.176	3,632	0.008381	$ 30.443	$5.267	20.92
10	Distribution October-May	10,661	0.006931	$ 73.892	10,661	0.008381	$ 89.352	$15.460	20.92
11	SBC	14,294	0.007767	$ 111.018	14,294	0.007767	$ 111.018	$0.000	0.00
12	NGC	14,294	0.000024	$ 0.343	14,294	0.000024	$ 0.343	$0.000	0.00
13	ZECRC	14,294	0.004000	$ 57.174	14,294	0.004000	$ 57.174	$0.000	0.00
14	Solar Pilot Recovery Charge	14,294	0.000063	$ 0.900	14,294	0.000063	$ 0.900	$0.000	0.00
15	Green Programs Recovery Charge	14,294	0.004920	$ 70.324	14,294	0.004920	$ 70.324	$0.000	0.00
16	Tax Adjustment Credit	14,294	(0.000459)	$ (6.561)	14,294	(0.000459)	$ (6.561)	$0.000	0.00
17	ECIP	14,294	0.000000	$ -	14,294	0.000000	$ -	$0.000	0.00
18									
19	Pole Charges			$ -			$ -	$0.000	0.00
20	Minimum			$ -			$ -	$0.000	0.00
21	Miscellaneous			$ 13.381			$ 13.381	$0.000	0.00
22	Delivery Subtotal			$ 619.524			$ 699.446	$79.922	12.90
23	Unbilled Delivery			$ -			$ -	$0.000	0.00
24	Delivery Subtotal w unbilled			$ 619.524			$ 699.446	$79.922	12.90
25									
26	**Supply-BGS**								
27	BGS June-September	3,632	0.061239	$ 222.441	3,632	0.061239	$ 222.441	$0.000	0.00
28	BGS October-May	10,661	0.066509	$ 709.063	10,661	0.066509	$ 709.063	$0.000	0.00
29	BGS Reconciliation-RSCP	14,294	0.000000	$ -	14,294	0.000000	$ -	$0.000	0.00
30	Miscellaneous			$ -			$ -	$0.000	0.00
31	Supply Subtotal			$ 931.504			$ 931.504	$0.000	0.00
32	Unbilled Supply			$ -			$ -	$0.000	0.00
33	Supply Subtotal w unbilled			$ 931.504			$ 931.504	$0.000	0.00
34									
35	Total Delivery + Supply	14,294		$ 1,551.028	14,294		$ 1,630.950	$79.922	5.15
36									
37	Notes:	All customers assumed to be on BGS.							
38		WH, WHS & BPL-POF revenues shown to 3 decimals.							
39		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	720.168	0	$13,189	720.168	0	$13,189	0.00	0.00
2	Metal Halide	175.692	0	4,763	175.692	0	4,763	0.00	0.00
3	Filament/Incandescent	0.792	0	4	0.792	0	4	0.00	0.00
4	Mercury Vapor	65.940	0	728	65.940	0	728	0.00	0.00
5	Induction	8.004	0	117	8.004	0	117	0.00	0.00
6	LED	168.036	0	4,570	168.036	0	4,570	0.00	0.00
7									
8	Distribution June-September	36,506	0.007784	$299	36,506	0.007784	$299	0.00	0.00
9	Distribution October-May	100,676	0.007784	769	100,676	0.007784	769	0.00	0.00
10	SBC	137,182	0.010012	1,373	137,182	0.010012	1,373	0.00	0.00
11	NGC	137,182	0.000057	8	137,182	0.000057	8	0.00	0.00
12	ZECRC	137,182	0.004001	549	137,182	0.004001	549	0.00	0.00
13	Solar Pilot Recovery Charge	137,182	0.000062	9	137,182	0.000062	9	0.00	0.00
14	Green Programs Recovery Charge	137,182	0.004920	675	137,182	0.004920	675	0.00	0.00
15	Tax Adjustment Credit	137,182	0.000000	0	137,182	0.000000	0	0.00	0.00
16	ECIP	137,182	0.000000	0	137,182	0.000000	0	0.00	0.00
17									
18	Pole Charges	361.188		3,591	361.188		3,591	0.00	0.00
19	Minimum			0			0	0.00	0.00
20	Miscellaneous			-319			-319	0	0.00
21	Delivery Subtotal	137,182		$30,323	137,182		$30,323	$0	0.00
22	Unbilled Delivery			322			322	0	0.00
23	Delivery Subtotal w unbilled			$30,645			$30,645	$0	0.00
24									
25	**Supply-BGS**								
26	BGS June-September	32,074	0.062855	2,016	32,074	0.062855	2,016	0	0.00
27	BGS October-May	99,317	0.062612	6,218	99,317	0.062612	6,218	0	0.00
28	BGS Reconciliation-RSCP	131,391	(0.000383)	(50)	131,391	(0.000383)	(50)	0	0.00
29	Miscellaneous			-1			-1	0	0.00
30	Supply subtotal			$8,183	131,391		$8,183	$0	0.00
31	Unbilled Supply			401			401	0	0.00
32	Supply subtotal w unbilled			$8,584			$8,584	$0	0.00
33									
34	Total Delivery + Supply	137,182		$39,229	137,182		$39,229	$0	0.00
35									
36	Notes:	Rates are annual averages derived from actual, excluding SUT.							

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
Rate Case 2023
(Units & Revenue in Thousands)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	High Pressure Sodium	720.168	0	$ 13,779	720.168	0	$ 15,070	$1,291	9.37
2	Metal Halide	175.692	0	4,901	175.692	0	5,096	195	3.98
3	Filament/Incandescent	0.792	0	7	0.792	0	7	0	0.00
4	Mercury Vapor	65.940	0	795	65.940	0	1,311	516	64.91
5	Induction	8.004	0	117	8.004	0	126	9	7.69
6	LED	168.036	0	3,421	168.036	0	3,597	176	5.14
7									
8	Distribution June-September	36,506	0.007355	$268	36,506	0.008719	$318	50	18.66
9	Distribution October-May	100,676	0.007355	740	100,676	0.008719	878	138	18.65
10	SBC	137,182	0.007767	1,065	137,182	0.007767	1,065	0	0.00
11	NGC	137,182	0.000024	3	137,182	0.000024	3	0	0.00
12	ZECRC	137,182	0.004000	549	137,182	0.004000	549	0	0.00
13	Solar Pilot Recovery Charge	137,182	0.000063	9	137,182	0.000063	9	0	0.00
14	Green Programs Recovery Charge	137,182	0.004920	675	137,182	0.004920	675	0	0.00
15	Tax Adjustment Credit	137,182	0.000000	0	137,182	0.000000	0	0	0.00
16	ECIP	137,182	0.000000	0	137,182	0.000000	0	0	0.00
17									
18	Pole Charges	361.188		4,026	361.188		4,511	485	12.05
19	Minimum			0			0	0	0.00
20	Miscellaneous			(319)			(319)	(0)	0.00
21	Delivery Subtotal			$30,036			$32,896	$2,860	9.52
22	Unbilled Delivery			319			349	30	9.40
23	Delivery Subtotal w unbilled			$30,355			$33,245	$2,890	9.52
24									
25	**Supply-BGS**								
26	BGS June-September	36,506	0.061239	2,236	36,506	0.061239	2,236	0	0.00
27	BGS October-May	100,676	0.066509	6,696	100,676	0.066509	6,696	0	0.00
28	BGS Reconciliation-RSCP	137,182	0.000000	0	137,182	0.000000	0	0	0.00
29	Miscellaneous			-1			-1	0	0.00
30	Supply Subtotal			$8,931			$8,931	$0	0.00
31	Unbilled Supply			437			437	0	0.00
32	Supply Subtotal w unbilled			$9,368			$9,368	$0	0.00
33									
34	Total Delivery + Supply	137,182		$39,724	137,182		$42,614	$2,890	7.28
35									
36	Notes:	All customers assumed to be on BGS.							
37		Annualized Weather Normalized Revenue reflects Delivery rates in effect 11/1/2023							

Electric Tariff Rates

Proposed Revenue Requirement Increase $ 522,084,186

Rate Schedules		Current Total Distribution Charges		Proposed Total Distribution Charges		Difference	
		Charge w/out SUT	Charge w/ SUT	Charge w/out SUT	Charge w/ SUT	w/out SUT	% w/out SUT
RS	Service Charge	$4.64	$4.95	$7.55	$8.05	$2.91	62.72%
	Distribution 0-600 Sum	$0.045704	$0.048732	$0.076528	$0.081598	$0.030824	67.44%
	Distribution 0-600 Win	$0.033344	$0.035553	$0.044823	$0.047793	$0.011479	34.43%
	Distribution over 600 Sum	$0.049525	$0.052806	$0.080349	$0.085672	$0.030824	62.24%
	Distribution over 600 Win	$0.033344	$0.035553	$0.044823	$0.047793	$0.011479	34.43%
RHS	Service Charge	$4.64	$4.95	$7.55	$8.05	$2.91	62.72%
	Distribution 0-600 Sum	$0.052835	$0.056335	$0.085167	$0.090809	$0.032332	61.19%
	Distribution 0-600 Win	$0.034719	$0.037019	$0.045533	$0.048550	$0.010814	31.15%
	Distribution over 600 Sum	$0.057735	$0.061560	$0.090067	$0.096034	$0.032332	56.00%
	Distribution over 600 Win	$0.017119	$0.018253	$0.027933	$0.029784	$0.010814	63.17%
	Common Use	$0.057735	$0.061560	$0.090067	$0.096034	$0.032332	56.00%
RLM	Service Charge	$13.07	$13.94	$13.07	$13.94	$0.00	0.00%
	Distrib. kWhr Summer On	$0.076937	$0.082034	$0.104311	$0.111222	$0.027374	35.58%
	Distrib. kWhr Summer Off	$0.016062	$0.017126	$0.019028	$0.020289	$0.002966	18.47%
	Distrib. kWhr Winter On	$0.016062	$0.017126	$0.019028	$0.020289	$0.002966	18.47%
	Distrib. kWhr Winter Off	$0.016062	$0.017126	$0.019028	$0.020289	$0.002966	18.47%
WH	Distribution	$0.049482	$0.052760	$0.067026	$0.071466	$0.017544	35.46%
WHS	Service Charge	$0.63	$0.67	$1.03	$1.10	$0.40	63.49%
	Distribution	$0.001925	$0.002053	$0.001826	$0.001947	($0.000099)	-5.14%
HS	Service Charge	$3.75	$4.00	$6.10	$6.50	$2.35	62.67%
	Distribution June-September	$0.098011	$0.104504	$0.106660	$0.113726	$0.008649	8.82%
	Distribution October-May	$0.029426	$0.031375	$0.055908	$0.059612	$0.026482	90.00%
GLP	Service Charge	$4.78	$5.10	$7.78	$8.30	$3.00	62.76%
	Service Charge-unmetered	$2.20	$2.35	$3.58	$3.82	$1.38	62.73%
	Service Charge-Night Use	$347.77	$370.81	$7.78	$8.30	($339.99)	-97.76%
	Distrib. KW Annual	$3.7660	$4.0155	$4.6357	$4.9428	$0.8697	23.09%
	Distrib. KW Summer	$9.4441	$10.0698	$15.3913	$16.4110	$5.9472	62.97%
	Distribution kWhr, June-September	$0.003079	$0.003283	$0.016508	$0.017602	$0.013429	436.15%
	Distribution kWhr, October-May	$0.007858	$0.008379	$0.003787	$0.004037	($0.004071)	-51.81%
	Distribution kWhr, Night use, June-September	$0.007858	$0.008379	$0.003787	$0.004037	($0.004071)	-51.81%
	Distribution kWhr, Night use, October-May	$0.007858	$0.008379	$0.003787	$0.004037	($0.004071)	-51.81%

Electric Tariff Rates

Proposed Revenue Requirement Increase $ 522,084,186

Rate Schedules		Current Total Distribution Charges		Proposed Total Distribution Charges		Difference	
		Charge w/out SUT	Charge w/ SUT	Charge w/out SUT	Charge w/ SUT	w/out SUT	% w/out SUT
LPL-Secondary	Service Charge	$347.77	$370.81	$347.77	$370.81	$0.00	0.00%
	Distrib. KW Annual	$3.6224	$3.8624	$3.7808	$4.0313	$0.1584	4.37%
	Distrib. KW Summer	$8.6179	$9.1888	$12.9480	$13.8058	$4.3301	50.25%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
LPL-Primary	Service Charge	$347.77	$370.81	$347.77	$370.81	$0.00	0.00%
	Service Charge-Alternate	$21.58	$23.01	$35.12	$37.45	$13.54	62.74%
	Distrib. KW Annual	$1.6885	$1.8004	$2.9510	$3.1465	$1.2625	74.77%
	Distrib. KW Summer	$9.3731	$9.9941	$13.2370	$14.1140	$3.8639	41.22%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
HTS-Subtransmission	Service Charge	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$0.00	0.00%
	Distrib. KW Annual	$1.1442	$1.2200	$1.8460	$1.9683	$0.7018	61.34%
	Distrib. KW Summer	$4.1361	$4.4101	$6.6731	$7.1152	$2.5370	61.34%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
HTS-HV	Service Charge	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$0.00	0.00%
	Distrib. KW Annual	$0.6322	$0.6741	$0.7861	$0.8382	$0.1539	24.34%
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	0.00%
BPL	Distribution Sum	$0.006894	$0.007351	$0.008160	$0.008701	$0.001266	18.36%
	Distribution Winter	$0.006894	$0.007351	$0.008160	$0.008701	$0.001266	18.36%
BPL-POF	Distribution Sum	$0.006931	$0.007390	$0.008381	$0.008936	$0.001450	20.92%
	Distribution Winter	$0.006931	$0.007390	$0.008381	$0.008936	$0.001450	20.92%
PSAL	Distribution Sum	$0.007355	$0.007842	$0.008719	$0.009297	$0.001364	18.55%
	Distribution Winter	$0.007355	$0.007842	$0.008719	$0.009297	$0.001364	18.55%

TYPICAL RESIDENTIAL ELECTRIC BILL IMPACTS

The effect of the proposed changes in the Rate Case 2023 (RC 2023) on typical residential Electric bills, if approved by the Board, is illustrated below:

Residential Electric Service - Average Monthly Bill				
If Your Average Monthly kWhr Use Is:	Then Your Present Monthly Bill (1) Would Be:	And Your Proposed Monthly Bill (2) Would Be:	Your Monthly Bill Change Would Be:	And Your Percent Change Would Be:
137	$32.00	$37.31	$5.31	16.59 %
275	59.21	66.72	7.51	12.68
548	113.64	125.55	11.91	10.48
650	134.25	147.74	13.49	10.05
1,000	205.89	225.43	19.54	9.49

(1) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect November 1, 2023, and assumes that the customer receives BGS-RSCP service from Public Service.

(2) Same as (1) except includes increase in the RC 2023.

Residential Electric Service - Monthly Summer Bill				
If Your Monthly Summer kWhr Use Is:	Then Your Present Monthly Summer Bill (3) Would Be:	And Your Proposed Monthly Summer Bill (4) Would Be:	Your Monthly Summer Bill Change Would Be:	And Your Percent Change Would Be:
171	$39.69	$47.60	$7.91	19.93 %
342	74.43	87.15	12.72	17.09
683	144.87	167.18	22.31	15.40
803	170.89	196.57	25.68	15.03
1,300	278.76	318.42	39.66	14.23

(3) Based upon current Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) and Delivery Rates in effect November 1, 2023, and assumes that the customer receives BGS-RSCP service from Public Service.

(4) Same as (3) except includes increase in the RC 2023.

COMPARISON OF TYPICAL BILLS
Rate Schedule RS
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution 0-600 June - September	1,762	748	1,343	1,768	2,088	2,251	2,329	2,349	2,370	2,380	2,390
3	Distribution 0-600 October - May	3,039	944	1,620	2,112	2,590	3,095	3,603	4,163	4,590	4,769	4,796
4	Distribution over 600 June - September	971	3	26	108	273	530	890	1,313	1,887	2,737	5,240
5	Distribution over 600 October - May	813	2	7	20	38	89	163	387	839	1,840	5,457
6	Total	6,585	1,697	2,996	4,008	4,988	5,965	6,985	8,212	9,686	11,727	17,882
7												
8	Avg Summer Use	683	188	342	469	590	695	805	916	1,064	1,279	1,907
9	Avg Winter Use	482	118	203	266	328	398	471	569	679	826	1,282
10												
11	**Present Bill**											
12	Total Delivery	$440.17	$157.14	$232.61	$291.97	$349.79	$406.92	$466.95	$537.98	$624.49	$744.89	$1,106.74
13	Total Supply	933.44	237.98	420.19	562.64	701.56	841.05	987.62	1,164.11	1,376.65	1,671.18	2,559.39
14		$1,373.61	$395.12	$652.80	$854.61	$1,051.35	$1,247.97	$1,454.57	$1,702.09	$2,001.14	$2,416.07	$3,666.13
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$614.36	$230.61	$334.71	$416.93	$496.74	$574.49	$656.05	$751.24	$868.06	$1,031.18	$1,520.19
20	Total Supply	933.44	237.98	420.19	562.64	701.56	841.05	987.62	1,164.11	1,376.65	1,671.18	2,559.39
21	Totals	$1,547.80	$468.59	$754.90	$979.57	$1,198.30	$1,415.54	$1,643.67	$1,915.35	$2,244.71	$2,702.36	$4,079.58
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$174.19	$73.47	$102.10	$124.96	$146.95	$167.57	$189.10	$213.26	$243.57	$286.29	$413.45
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$174.19	$73.47	$102.10	$124.96	$146.95	$167.57	$189.10	$213.26	$243.57	$286.29	$413.45
29												
30												
31												
32	**Increase Percent**											
33	Delivery	39.6	46.8	43.9	42.8	42.0	41.2	40.5	39.6	39.0	38.4	37.4
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	12.7	18.6	15.6	14.6	14.0	13.4	13.0	12.5	12.2	11.8	11.3
36												
37												
38												
39	Notes:	Bills include SUT										
40		Each band represents a decile of customers segmented by annual kWhr usage.										
41												

COMPARISON OF TYPICAL BILLS
Rate Schedule RS
Including Tax Adjustment Credit and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution 0-600 June - September	1,762	748	1,343	1,768	2,088	2,251	2,329	2,349	2,370	2,380	2,390
3	Distribution 0-600 October - May	3,039	944	1,620	2,112	2,590	3,095	3,603	4,163	4,590	4,769	4,796
4	Distribution over 600 June - September	971	3	26	108	273	530	890	1,313	1,887	2,737	5,240
5	Distribution over 600 October - May	813	2	7	20	38	89	163	387	839	1,840	5,457
6	Total	6,585	1,697	2,996	4,008	4,988	5,965	6,985	8,212	9,686	11,727	17,882
7												
8	Avg Summer Use	683	188	342	469	590	695	805	916	1,064	1,279	1,907
9	Avg Winter Use	482	118	203	266	328	398	471	569	679	826	1,282
10												
11	**Present Bill**											
12	Total Delivery	$440.17	$157.14	$232.61	$291.97	$349.79	$406.92	$466.95	$537.98	$624.49	$744.89	$1,106.74
13	Total Supply	933.44	237.98	420.19	562.64	701.56	841.05	987.62	1,164.11	1,376.65	1,671.18	2,559.39
14		$1,373.61	$395.12	$652.80	$854.61	$1,051.35	$1,247.97	$1,454.57	$1,702.09	$2,001.14	$2,416.07	$3,666.13
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$583.11	$222.56	$320.49	$397.91	$473.07	$546.19	$622.91	$712.28	$822.10	$975.54	$1,435.34
20	Total Supply	933.44	237.98	420.19	562.64	701.56	841.05	987.62	1,164.11	1,376.65	1,671.18	2,559.39
21	Totals	$1,516.55	$460.54	$740.68	$960.55	$1,174.63	$1,387.24	$1,610.53	$1,876.39	$2,198.75	$2,646.72	$3,994.73
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$142.94	$65.42	$87.88	$105.94	$123.28	$139.27	$155.96	$174.30	$197.61	$230.65	$328.60
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$142.94	$65.42	$87.88	$105.94	$123.28	$139.27	$155.96	$174.30	$197.61	$230.65	$328.60
29												
30												
31												
32	**Increase Percent**											
33	Delivery	32.5	41.6	37.8	36.3	35.2	34.2	33.4	32.4	31.6	31.0	29.7
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	10.4	16.6	13.5	12.4	11.7	11.2	10.7	10.2	9.9	9.5	9.0
36												
37												
38												
39	Notes:	Bills include SUT										
40		Each band represents a decile of customers segmented by annual kWhr usage.										
41		Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

COMPARISON OF TYPICAL BILLS
Rate Schedule RHS
Distribution Only

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution 0-600 June - September	1,912	211	1,365	1,776	2,000	2,121	2,225	2,293	2,329	2,368	2,385
3	Distribution 0-600 October - May	3,937	375	3,320	4,460	4,730	4,791	4,799	4,800	4,800	4,800	4,800
4	Distribution over 600 June - September	907	152	53	195	369	587	920	1,307	1,858	2,569	4,637
5	Distribution over 600 October - May	6,256	292	222	900	1,709	2,763	3,895	5,549	7,547	10,365	18,596
6	Total	13,011	1,029	4,960	7,332	8,808	10,262	11,840	13,949	16,534	20,102	30,417
7												
8	Avg Summer Use	705	91	354	493	592	677	786	900	1,047	1,234	1,755
9	Avg Winter Use	1,274	83	443	670	805	944	1,087	1,294	1,543	1,896	2,924
10												
11	**Present Bill**											
12	Total Delivery	$682.91	$115.67	$342.77	$465.74	$536.51	$600.64	$672.23	$762.49	$874.69	$1,026.97	$1,464.06
13	Total Supply	1,573.48	124.36	593.08	879.28	1,058.04	1,235.24	1,428.12	1,686.31	2,003.58	2,441.31	3,707.64
14	Totals	$2,256.39	$240.03	$935.85	$1,345.02	$1,594.55	$1,835.88	$2,100.35	$2,448.80	$2,878.27	$3,468.28	$5,171.70
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$934.81	$173.07	$469.69	$632.69	$729.63	$818.30	$918.11	$1,043.13	$1,198.61	$1,409.23	$2,013.11
20	Total Supply	1,573.48	124.36	593.08	879.28	1,058.04	1,235.24	1,428.12	1,686.31	2,003.58	2,441.31	3,707.64
21	Totals	$2,508.29	$297.43	$1,062.77	$1,511.97	$1,787.67	$2,053.54	$2,346.23	$2,729.44	$3,202.19	$3,850.54	$5,720.75
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$251.90	$57.40	$126.92	$166.95	$193.12	$217.66	$245.88	$280.64	$323.92	$382.26	$549.05
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$251.90	$57.40	$126.92	$166.95	$193.12	$217.66	$245.88	$280.64	$323.92	$382.26	$549.05
29												
30												
31												
32	**Increase Percent**											
33	Delivery	36.9	49.6	37.0	35.8	36.0	36.2	36.6	36.8	37.0	37.2	37.5
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	11.2	23.9	13.6	12.4	12.1	11.9	11.7	11.5	11.3	11.0	10.6
36												
37												
38												
39	Notes:	Bills include SUT										
40		Each band represents a decile of customers segmented by annual kWhr usage.										

COMPARISON OF TYPICAL BILLS
Rate Schedule RHS
Including Tax Adjustment Credit and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution 0-600 June - September	1,912	211	1,365	1,776	2,000	2,121	2,225	2,293	2,329	2,368	2,385
3	Distribution 0-600 October - May	3,937	375	3,320	4,460	4,730	4,791	4,799	4,800	4,800	4,800	4,800
4	Distribution over 600 June - September	907	152	53	195	369	587	920	1,307	1,858	2,569	4,637
5	Distribution over 600 October - May	6,256	292	222	900	1,709	2,763	3,895	5,549	7,547	10,365	18,596
6	Total	13,011	1,029	4,960	7,332	8,808	10,262	11,840	13,949	16,534	20,102	30,417
7												
8	Avg Summer Use	705	91	354	493	592	677	786	900	1,047	1,234	1,755
9	Avg Winter Use	1,274	83	443	670	805	944	1,087	1,294	1,543	1,896	2,924
10												
11	**Present Bill**											
12	Total Delivery	$682.91	$115.67	$342.77	$465.74	$536.51	$600.64	$672.23	$762.49	$874.69	$1,026.97	$1,464.06
13	Total Supply	1,573.48	124.36	593.08	879.28	1,058.04	1,235.24	1,428.12	1,686.31	2,003.58	2,441.31	3,707.64
14	Totals	$2,256.39	$240.03	$935.85	$1,345.02	$1,594.55	$1,835.88	$2,100.35	$2,448.80	$2,878.27	$3,468.28	$5,171.70
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$843.91	$165.88	$435.03	$581.47	$668.10	$746.61	$835.40	$945.68	$1,083.11	$1,268.80	$1,800.62
20	Total Supply	1,573.48	124.36	593.08	879.28	1,058.04	1,235.24	1,428.12	1,686.31	2,003.58	2,441.31	3,707.64
21	Totals	$2,417.39	$290.24	$1,028.11	$1,460.75	$1,726.14	$1,981.85	$2,263.52	$2,631.99	$3,086.69	$3,710.11	$5,508.26
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$161.00	$50.21	$92.26	$115.73	$131.59	$145.97	$163.17	$183.19	$208.42	$241.83	$336.56
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$161.00	$50.21	$92.26	$115.73	$131.59	$145.97	$163.17	$183.19	$208.42	$241.83	$336.56
29												
30												
31												
32	**Increase Percent**											
33	Delivery	23.6	43.4	26.9	24.8	24.5	24.3	24.3	24.0	23.8	23.5	23.0
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	7.1	20.9	9.9	8.6	8.3	8.0	7.8	7.5	7.2	7.0	6.5
36												
37												
38												
39	Notes:	Bills include SUT										
40		Each band represents a decile of customers segmented by annual kWhr usage.										
41		Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

COMPARISON OF TYPICAL BILLS
Rate Schedule RLM
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution June - September On Peak	3,223	1,204	1,922	2,302	2,670	3,043	3,452	3,829	4,380	5,280	7,999
3	Distribution June - September Off Peak	3,531	1,344	2,045	2,425	2,781	3,186	3,553	3,970	4,629	5,518	8,678
4	Distribution October - May On Peak	3,877	1,315	1,931	2,323	2,717	3,070	3,565	4,081	4,708	5,759	9,680
5	Distribution October - May Off Peak	5,091	1,816	2,571	3,169	3,602	4,093	4,619	5,331	6,186	7,647	12,837
6	Total	15,722	5,679	8,469	10,218	11,770	13,392	15,189	17,210	19,903	24,203	39,194
7												
8	Avg Summer Use	1,689	637	992	1,182	1,363	1,557	1,751	1,950	2,252	2,699	4,169
9	Avg Winter Use	1,121	391	563	686	790	895	1,023	1,176	1,362	1,676	2,815
10												
11	**Present Bill**											
12	Total Delivery	$914.00	$439.59	$581.53	$665.98	$742.95	$822.62	$910.65	$1,004.19	$1,132.01	$1,337.43	$2,026.36
13	Total Supply	3,358.89	1,211.97	1,810.24	2,183.55	2,516.98	2,863.42	3,250.26	3,681.48	4,255.45	5,174.81	8,373.21
14	Totals	$4,272.89	$1,651.56	$2,391.77	$2,849.53	$3,259.93	$3,686.04	$4,160.91	$4,685.67	$5,387.46	$6,512.24	$10,399.57
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$1,047.60	$488.87	$658.34	$758.19	$849.65	$944.16	$1,048.54	$1,158.28	$1,308.96	$1,551.39	$2,358.50
20	Total Supply	3,358.89	1,211.97	1,810.24	2,183.55	2,516.98	2,863.42	3,250.26	3,681.48	4,255.45	5,174.81	8,373.21
21	Totals	$4,406.49	$1,700.84	$2,468.58	$2,941.74	$3,366.63	$3,807.58	$4,298.80	$4,839.76	$5,564.41	$6,726.20	$10,731.71
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$133.60	$49.28	$76.81	$92.21	$106.70	$121.54	$137.89	$154.09	$176.95	$213.96	$332.14
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$133.60	$49.28	$76.81	$92.21	$106.70	$121.54	$137.89	$154.09	$176.95	$213.96	$332.14
29												
30												
31												
32	**Increase Percent**											
33	Delivery	14.6	11.2	13.2	13.8	14.4	14.8	15.1	15.3	15.6	16.0	16.4
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	3.1	3.0	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.2
36												
37												
38												
39	Notes:	Bills include SUT.										
40		Each band represents a decile of customers segmented by annual kWhr usage.										

COMPARISON OF TYPICAL BILLS
Rate Schedule RLM
Including Tax Adjustment Credit and Distribution Adjustment Charge

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distribution June - September On Peak	3,223	1,204	1,922	2,302	2,670	3,043	3,452	3,829	4,380	5,280	7,999
3	Distribution June - September Off Peak	3,531	1,344	2,045	2,425	2,781	3,186	3,553	3,970	4,629	5,518	8,678
4	Distribution October - May On Peak	3,877	1,315	1,931	2,323	2,717	3,070	3,565	4,081	4,708	5,759	9,680
5	Distribution October - May Off Peak	5,091	1,816	2,571	3,169	3,602	4,093	4,619	5,331	6,186	7,647	12,837
6	Total	15,722	5,679	8,469	10,218	11,770	13,392	15,189	17,210	19,903	24,203	39,194
7												
8	Avg Summer Use	1,689	637	992	1,182	1,363	1,557	1,751	1,950	2,252	2,699	4,169
9	Avg Winter Use	1,121	391	563	686	790	895	1,023	1,176	1,362	1,676	2,815
10												
11	**Present Bill**											
12	Total Delivery	$914.00	$439.59	$581.53	$665.98	$742.95	$822.62	$910.65	$1,004.19	$1,132.01	$1,337.43	$2,026.36
13	Total Supply	3,358.89	1,211.97	1,810.24	2,183.55	2,516.98	2,863.42	3,250.26	3,681.48	4,255.45	5,174.81	8,373.21
14	Totals	$4,272.89	$1,651.56	$2,391.77	$2,849.53	$3,259.93	$3,686.04	$4,160.91	$4,685.67	$5,387.46	$6,512.24	$10,399.57
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$978.81	$464.02	$621.28	$713.48	$798.16	$885.57	$982.09	$1,082.99	$1,221.88	$1,445.50	$2,187.04
20	Total Supply	3,358.89	1,211.97	1,810.24	2,183.55	2,516.98	2,863.42	3,250.26	3,681.48	4,255.45	5,174.81	8,373.21
21	Totals	$4,337.70	$1,675.99	$2,431.52	$2,897.03	$3,315.14	$3,748.99	$4,232.35	$4,764.47	$5,477.33	$6,620.31	$10,560.25
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$64.81	$24.43	$39.75	$47.50	$55.21	$62.95	$71.44	$78.80	$89.87	$108.07	$160.68
27	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Totals	$64.81	$24.43	$39.75	$47.50	$55.21	$62.95	$71.44	$78.80	$89.87	$108.07	$160.68
29												
30												
31												
32	**Increase Percent**											
33	Delivery	7.1	5.6	6.8	7.1	7.4	7.7	7.8	7.8	7.9	8.1	7.9
34	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Totals	1.5	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.5
36												
37												
38												
39	Notes:	Bills include SUT.										
40		Each band represents a decile of customers segmented by annual kWhr usage.										
		Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Estimated Demand
Distribution Only

			Annual Usages									
	Units	**GLP Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	96	8	17	26	38	54	74	103	145	213	512
3	Distrib. KW June-September	96	3	6	9	14	19	27	37	53	79	188
4	Distribution kWhr, June-September	9,444	266	895	1,584	2,398	3,431	5,153	8,006	12,998	23,784	66,911
5	Distribution kWhr, October-May	16,431	563	1,802	3,070	4,502	6,407	9,281	14,101	22,702	39,147	113,456
6												
7												
8	Total	25,875	829	2,697	4,654	6,900	9,838	14,434	22,107	35,700	62,932	180,367
9												
10	Gen Cap Obl June-September	25	2	5	8	12	17	24	34	48	72	173
11	Gen Cap Obl October-May	46	5	10	16	24	34	48	68	96	145	347
12	Trans Cap Obl	64	7	15	25	36	51	72	102	144	217	520
13												
14												
15	**Present Bill**											
16	Total Delivery	$2,157.33	$150.05	$272.03	$400.13	$564.88	$772.21	$1,068.17	$1,511.97	$2,215.22	$3,480.97	$8,953.98
17	Total Supply	2,827.24	167.26	423.98	704.45	1,037.94	1,473.90	2,111.09	3,116.42	4,715.12	7,772.19	20,744.95
18	Totals	$4,984.57	$317.31	$696.01	$1,104.58	$1,602.82	$2,246.11	$3,179.26	$4,628.39	$6,930.34	$11,253.16	$29,698.93
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$2,959.57	$214.12	$367.37	$529.63	$739.38	$1,002.31	$1,378.00	$1,937.13	$2,812.21	$4,388.73	$11,124.86
24	Total Supply	2,827.24	167.26	423.98	704.45	1,037.94	1,473.90	2,111.09	3,116.42	4,715.12	7,772.19	20,744.95
25	Totals	$5,786.81	$381.38	$791.35	$1,234.08	$1,777.32	$2,476.21	$3,489.09	$5,053.55	$7,527.33	$12,160.92	$31,869.81
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$802.24	$64.07	$95.34	$129.50	$174.50	$230.10	$309.83	$425.16	$596.99	$907.76	$2,170.88
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$802.24	$64.07	$95.34	$129.50	$174.50	$230.10	$309.83	$425.16	$596.99	$907.76	$2,170.88
33												
34												
35												
36	**Increase Percent**											
37	Delivery	37.2	42.7	35.0	32.4	30.9	29.8	29.0	28.1	26.9	26.1	24.2
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	16.1	20.2	13.7	11.7	10.9	10.2	9.7	9.2	8.6	8.1	7.3
40												
41												
42												
43	Notes:	Bills include SUT										
44		Each band represents a decile of customers segmented by annual kWhr usage.										

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Estimated Demand
Including Tax Adjustment Credit and Distribution Adjustment Charge
Annual Usages

	Units	GLP Class Avg	Band 1	Band 2	Band 3	Band 4	Band 5	Band 6	Band 7	Band 8	Band 9	Band 10
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	96	8	17	26	38	54	74	103	145	213	512
3	Distrib. KW June-September	96	3	6	9	14	19	27	37	53	79	188
4	Distribution kWhr, June-September	9,444	266	895	1,584	2,398	3,431	5,153	8,006	12,998	23,784	66,911
5	Distribution kWhr, October-May	16,431	563	1,802	3,070	4,502	6,407	9,281	14,101	22,702	39,147	113,456
6												
7												
8	Total	25,875	829	2,697	4,654	6,900	9,838	14,434	22,107	35,700	62,932	180,367
9												
10	Gen Cap Obl June-September	25	2	5	8	12	17	24	34	48	72	173
11	Gen Cap Obl October-May	46	5	10	16	24	34	48	68	96	145	347
12	Trans Cap Obl	64	7	15	25	36	51	72	102	144	217	520
13												
14												
15	**Present Bill**											
16	Total Delivery	$2,157.33	$150.05	$272.03	$400.13	$564.88	$772.21	$1,068.17	$1,511.97	$2,215.22	$3,480.97	$8,953.98
17	Total Supply	2,827.24	167.26	423.98	704.45	1,037.94	1,473.90	2,111.09	3,116.42	4,715.12	7,772.19	20,744.95
18	Totals	$4,984.57	$317.31	$696.01	$1,104.58	$1,602.82	$2,246.11	$3,179.26	$4,628.39	$6,930.34	$11,253.16	$29,698.93
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$2,940.50	$213.51	$365.39	$526.20	$734.30	$995.05	$1,367.36	$1,920.84	$2,785.89	$4,342.35	$10,991.93
24	Total Supply	2,827.24	167.26	423.98	704.45	1,037.94	1,473.90	2,111.09	3,116.42	4,715.12	7,772.19	20,744.95
25	Totals	$5,767.74	$380.77	$789.37	$1,230.65	$1,772.24	$2,468.95	$3,478.45	$5,037.26	$7,501.01	$12,114.54	$31,736.88
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$783.17	$63.46	$93.36	$126.07	$169.42	$222.84	$299.19	$408.87	$570.67	$861.38	$2,037.95
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$783.17	$63.46	$93.36	$126.07	$169.42	$222.84	$299.19	$408.87	$570.67	$861.38	$2,037.95
33												
34												
35												
36	**Increase Percent**											
37	Delivery	36.3	42.3	34.3	31.5	30.0	28.9	28.0	27.0	25.8	24.7	22.8
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	15.7	20.0	13.4	11.4	10.6	9.9	9.4	8.8	8.2	7.7	6.9
40												
41												
42												
43	Notes:	Bills include SUT										
44		Each band represents a decile of customers segmented by annual kWhr usage.										
		Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Measured Demand
Distribution Only

	Units		Annual Usages										
			Class Avg	Band 1	Band 2	Band 3	Band 4	Band 5	Band 6	Band 7	Band 8	Band 9	Band 10
1	Serv Chg		12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual		96	2	4	7	10	13	18	25	34	48	95
3	Distrib. KW June-September		96	1	1	2	3	4	6	9	12	16	30
4	Distribution kWhr, June-September		9,444	50	126	207	308	437	612	849	1,162	1,611	3,003
5	Distribution kWhr, October-May		16,431	110	274	448	654	901	1,231	1,659	2,256	3,195	6,487
6													
7													
8		Total	25,875	160	400	655	962	1,339	1,843	2,508	3,417	4,805	9,490
9													
10	Gen Cap Obl June-September		25	0	1	2	3	4	5	7	10	14	24
11	Gen Cap Obl October-May		46	1	2	4	5	8	11	15	20	28	49
12	Trans Cap Obl		64	1	3	6	8	11	16	22	30	41	73
13													
14													
15	**Present Bill**												
16	Total Delivery		$2,157.33	$78.84	$105.24	$133.08	$166.81	$208.94	$265.37	$340.47	$441.82	$593.99	$1,096.07
17	Total Supply		2,827.24	33.63	79.33	130.33	190.69	268.08	374.07	514.90	698.48	966.33	1,776.95
18	Totals		$4,984.57	$112.47	$184.57	$263.41	$357.50	$477.02	$639.44	$855.37	$1,140.30	$1,560.32	$2,873.02
19													
20													
21													
22	**Proposed Bill**												
23	Total Delivery		$2,959.57	$122.24	$156.14	$191.89	$235.38	$289.99	$363.25	$461.11	$592.54	$788.39	$1,427.80
24	Total Supply		2,827.24	33.63	79.33	130.33	190.69	268.08	374.07	514.90	698.48	966.33	1,776.95
25	Totals		$5,786.81	$155.87	$235.47	$322.22	$426.07	$558.07	$737.32	$976.01	$1,291.02	$1,754.72	$3,204.75
26													
27													
28													
29	**Increase Amount**												
30	Delivery		$802.24	$43.40	$50.90	$58.81	$68.57	$81.05	$97.88	$120.64	$150.72	$194.40	$331.73
31	Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals		$802.24	$43.40	$50.90	$58.81	$68.57	$81.05	$97.88	$120.64	$150.72	$194.40	$331.73
33													
34													
35													
36	**Increase Percent**												
37	Delivery		37.2	55.0	48.4	44.2	41.1	38.8	36.9	35.4	34.1	32.7	30.3
38	Supply		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals		16.1	38.6	27.6	22.3	19.2	17.0	15.3	14.1	13.2	12.5	11.5
40													
41													
42													
43		Notes:	Bills include SUT										
44			Each band represents a decile of customers segmented by annual load factor.										

COMPARISON OF TYPICAL BILLS
Rate Schedule GLP
Measured Demand
Including Tax Adjustment Credit and Distribution Adjustment Charge

	Units		Annual Usages Class Avg	Band 1	Band 2	Band 3	Band 4	Band 5	Band 6	Band 7	Band 8	Band 9	Band 10
1	Serv Chg		12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual		96	2	4	7	10	13	18	25	34	48	95
3	Distrib. KW June-September		96	1	1	2	3	4	6	9	12	16	30
4	Distribution kWhr, June-September		9,444	50	126	207	308	437	612	849	1,162	1,611	3,003
5	Distribution kWhr, October-May		16,431	110	274	448	654	901	1,231	1,659	2,256	3,195	6,487
6													
7													
8		Total	25,875	160	400	655	962	1,339	1,843	2,508	3,417	4,805	9,490
9													
10	Gen Cap Obl June-September		25	0	1	2	3	4	5	7	10	14	24
11	Gen Cap Obl October-May		46	1	2	4	5	8	11	15	20	28	49
12	Trans Cap Obl		64	1	3	6	8	11	16	22	30	41	73
13													
14													
15	**Present Bill**												
16	Total Delivery		$2,157.33	$78.84	$105.24	$133.08	$166.81	$208.94	$265.37	$340.47	$441.82	$593.99	$1,096.07
17	Total Supply		2,827.24	33.63	79.33	130.33	190.69	268.08	374.07	514.90	698.48	966.33	1,776.95
18	Totals		$4,984.57	$112.47	$184.57	$263.41	$357.50	$477.02	$639.44	$855.37	$1,140.30	$1,560.32	$2,873.02
19													
20													
21													
22	**Proposed Bill**												
23	Total Delivery		$2,940.50	$122.11	$155.84	$191.41	$234.67	$289.01	$361.90	$459.26	$590.03	$784.86	$1,420.81
24	Total Supply		2,827.24	33.63	79.33	130.33	190.69	268.08	374.07	514.90	698.48	966.33	1,776.95
25	Totals		$5,767.74	$155.74	$235.17	$321.74	$425.36	$557.09	$735.97	$974.16	$1,288.51	$1,751.19	$3,197.76
26													
27													
28													
29	**Increase Amount**												
30	Delivery		$783.17	$43.27	$50.60	$58.33	$67.86	$80.07	$96.53	$118.79	$148.21	$190.87	$324.74
31	Supply		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals		$783.17	$43.27	$50.60	$58.33	$67.86	$80.07	$96.53	$118.79	$148.21	$190.87	$324.74
33													
34													
35													
36	**Increase Percent**												
37	Delivery		36.3	54.9	48.1	43.8	40.7	38.3	36.4	34.9	33.5	32.1	29.6
38	Supply		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals		15.7	38.5	27.4	22.1	19.0	16.8	15.1	13.9	13.0	12.2	11.3
40													
41													
42													
43		Notes:	Bills include SUT										
44			Each band represents a decile of customers segmented by annual load factor.										
			Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Secondary
Distribution Only

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	2,714	1,400	2,275	2,529	2,950	3,530	4,212	5,262	6,769	9,438	18,652
3	Distrib. KW June - September	963	279	433	497	577	686	808	992	1,272	1,754	3,390
4	Distribution kWhr On Peak June-September	181,334	25,399	53,843	74,938	96,866	120,012	151,553	192,571	262,442	383,894	843,794
5	Distribution kWhr Off Peak June-September	195,549	25,268	54,364	74,625	95,933	118,964	149,828	191,282	256,008	373,056	813,112
6	Distribution kWhr On Peak October-May	356,006	47,089	97,005	131,980	161,477	201,435	244,692	316,210	421,554	621,580	1,359,169
7	Distribution kWhr Off Peak October-May	354,467	44,613	90,036	122,749	163,984	209,972	270,059	351,617	480,408	714,766	1,634,643
8	Total	1,087,356	142,369	295,247	404,292	518,261	650,383	816,132	1,051,680	1,420,413	2,093,296	4,650,718
9												
10	Gen Cap Obl June-September	292	117	271	377	457	554	684	853	1,132	1,641	3,366
11	Gen Cap Obl October-May	591	234	541	753	915	1,109	1,367	1,706	2,265	3,282	6,733
12	Trans Cap Obl	764	351	812	1,130	1,372	1,663	2,051	2,558	3,397	4,924	10,099
13												
14												
15	**Present Bill**											
16	Total Delivery	$45,980.51	$16,475.16	$24,929.15	$28,706.94	$33,542.22	$39,753.42	$47,188.51	$58,249.63	$74,816.59	$104,377.16	$210,308.80
17	Total Supply	93,186.15	16,427.56	35,502.74	48,934.62	61,371.14	75,994.94	94,683.50	120,540.58	161,824.85	237,050.34	512,123.63
18	Totals	$139,166.66	$32,902.72	$60,431.89	$77,641.56	$94,913.36	$115,748.36	$141,872.01	$178,790.21	$236,641.44	$341,427.50	$722,432.43
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$50,886.26	$17,999.84	$27,312.55	$31,430.07	$36,704.93	$43,515.53	$51,630.66	$63,717.19	$81,833.69	$114,069.14	$229,108.92
24	Total Supply	93,186.15	16,427.56	35,502.74	48,934.62	61,371.14	75,994.94	94,683.50	120,540.58	161,824.85	237,050.34	512,123.63
25	Totals	$144,072.41	$34,427.40	$62,815.29	$80,364.69	$98,076.07	$119,510.47	$146,314.16	$184,257.77	$243,658.54	$351,119.48	$741,232.55
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$4,905.75	$1,524.68	$2,383.40	$2,723.13	$3,162.71	$3,762.11	$4,442.15	$5,467.56	$7,017.10	$9,691.98	$18,800.12
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$4,905.75	$1,524.68	$2,383.40	$2,723.13	$3,162.71	$3,762.11	$4,442.15	$5,467.56	$7,017.10	$9,691.98	$18,800.12
33												
34												
35												
36	**Increase Percent**											
37	Delivery	10.7	9.3	9.6	9.5	9.4	9.5	9.4	9.4	9.4	9.3	8.9
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	3.5	4.6	3.9	3.5	3.3	3.3	3.1	3.1	3.0	2.8	2.6
40												
41												
42												

43 Notes: Bills include SUT
44 Each band represents a decile of customers segmented by annual load factor.
45 For presentation purposes, all bands billed at LPL-S BGS weighted average of the three subsets.

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Secondary
Including Tax Adjustment Credit and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	2,714	1,400	2,275	2,529	2,950	3,530	4,212	5,262	6,769	9,438	18,652
3	Distrib. KW June - September	963	279	433	497	577	686	808	992	1,272	1,754	3,390
4	Distribution kWhr On Peak June-September	181,334	25,399	53,843	74,938	96,866	120,012	151,553	192,571	262,442	383,894	843,794
5	Distribution kWhr Off Peak June-September	195,549	25,268	54,364	74,625	95,933	118,964	149,828	191,282	256,008	373,056	813,112
6	Distribution kWhr On Peak October-May	356,006	47,089	97,005	131,980	161,477	201,435	244,692	316,210	421,554	621,580	1,359,169
7	Distribution kWhr Off Peak October-May	354,467	44,613	90,036	122,749	163,984	209,972	270,059	351,617	480,408	714,766	1,634,643
8	Total	1,087,356	142,369	295,247	404,292	518,261	650,383	816,132	1,051,680	1,420,413	2,093,296	4,650,718
9												
10	Gen Cap Obl June-September	292	117	271	377	457	554	684	853	1,132	1,641	3,366
11	Gen Cap Obl October-May	591	234	541	753	915	1,109	1,367	1,706	2,265	3,282	6,733
12	Trans Cap Obl	764	351	812	1,130	1,372	1,663	2,051	2,558	3,397	4,924	10,099
13												
14												
15	**Present Bill**											
16	Total Delivery	$45,980.51	$16,475.16	$24,929.15	$28,706.94	$33,542.22	$39,753.42	$47,188.51	$58,249.63	$74,816.59	$104,377.16	$210,308.80
17	Total Supply	93,186.15	16,427.56	35,502.74	48,934.62	61,371.14	75,994.94	94,683.50	120,540.58	161,824.85	237,050.34	512,123.63
18	Totals	$139,166.66	$32,902.72	$60,431.89	$77,641.56	$94,913.36	$115,748.36	$141,872.01	$178,790.21	$236,641.44	$341,427.50	$722,432.43
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$50,850.38	$17,995.14	$27,302.81	$31,416.73	$36,687.83	$43,494.06	$51,603.73	$63,682.48	$81,786.81	$114,000.06	$228,955.45
24	Total Supply	93,186.15	16,427.56	35,502.74	48,934.62	61,371.14	75,994.94	94,683.50	120,540.58	161,824.85	237,050.34	512,123.63
25	Totals	$144,036.53	$34,422.70	$62,805.55	$80,351.35	$98,058.97	$119,489.00	$146,287.23	$184,223.06	$243,611.66	$351,050.40	$741,079.08
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$4,869.87	$1,519.98	$2,373.66	$2,709.79	$3,145.61	$3,740.64	$4,415.22	$5,432.85	$6,970.22	$9,622.90	$18,646.65
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$4,869.87	$1,519.98	$2,373.66	$2,709.79	$3,145.61	$3,740.64	$4,415.22	$5,432.85	$6,970.22	$9,622.90	$18,646.65
33												
34												
35												
36	**Increase Percent**											
37	Delivery	10.6	9.2	9.5	9.4	9.4	9.4	9.4	9.3	9.3	9.2	8.9
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	3.5	4.6	3.9	3.5	3.3	3.2	3.1	3.0	2.9	2.8	2.6
40												
41												
42												

43 Notes: Bills include SUT
44 Each band represents a decile of customers segmented by annual load factor.
45 For presentation purposes, all bands billed at LPL-S BGS weighted average of the three subsets.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Primary
Distribution Only

						Annual Usages						
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	2,714	1,100	2,811	4,768	7,573	10,236	14,038	19,799	25,940	35,106	57,845
3	Distrib. KW Summer	963	165	494	859	1,346	1,883	2,523	3,796	4,772	6,480	10,839
4	Distribution kWhr On Peak June-September	181,334	20,156	67,741	130,817	204,213	335,781	498,004	752,300	1,045,259	1,559,226	2,988,621
5	Distribution kWhr Off Peak June-September	195,549	20,326	66,030	127,966	200,581	333,081	482,184	754,173	1,018,973	1,544,192	2,895,629
6	Distribution kWhr On Peak October-May	356,006	46,689	130,894	238,866	368,645	575,666	826,909	1,189,320	1,649,063	2,332,737	4,409,388
7	Distribution kWhr Off Peak October-May	354,467	57,709	144,733	263,185	425,957	673,746	1,023,554	1,382,934	1,999,682	3,007,330	5,579,838
8	Total	1,087,356	144,880	409,398	760,834	1,199,396	1,918,274	2,830,651	4,078,727	5,712,977	8,443,485	15,873,475
9												
10	Gen Cap Obl June-September	292	69	271	433	822	1,223	1,779	3,203	3,906	5,459	10,838
11	Gen Cap Obl October-May	591	137	541	866	1,644	2,445	3,559	6,407	7,812	10,917	21,675
12	Trans Cap Obl	764	206	812	1,298	2,465	3,668	5,338	9,610	11,718	16,376	32,513
13												
14												
15	**Present Bill**											
16	Total Delivery	$38,150.11	$10,632.94	$21,669.17	$35,048.10	$52,701.67	$75,548.62	$104,888.19	$150,003.75	$199,659.66	$281,405.50	$497,023.39
17	Total Supply	110,250.04	16,841.52	53,475.31	94,514.54	158,993.33	248,068.93	364,138.83	572,459.44	759,148.06	1,100,241.99	2,110,817.32
18	Totals	$148,400.15	$27,474.46	$75,144.48	$129,562.64	$211,695.00	$323,617.55	$469,027.02	$722,463.19	$958,807.72	$1,381,647.49	$2,607,840.71
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$45,771.74	$12,792.28	$27,487.11	$45,006.47	$68,441.29	$97,085.34	$134,178.90	$192,293.09	$254,239.65	$355,356.53	$619,544.41
24	Total Supply	110,250.04	16,841.52	53,475.31	94,514.54	158,993.33	248,068.93	364,138.83	572,459.44	759,148.06	1,100,241.99	2,110,817.32
25	Totals	$156,021.78	$29,633.80	$80,962.42	$139,521.01	$227,434.62	$345,154.27	$498,317.73	$764,752.53	$1,013,387.71	$1,455,598.52	$2,730,361.73
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$7,621.63	$2,159.34	$5,817.94	$9,958.37	$15,739.62	$21,536.72	$29,290.71	$42,289.34	$54,579.99	$73,951.03	$122,521.02
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$7,621.63	$2,159.34	$5,817.94	$9,958.37	$15,739.62	$21,536.72	$29,290.71	$42,289.34	$54,579.99	$73,951.03	$122,521.02
33												
34												
35												
36	**Increase Percent**											
37	Delivery	20.0	20.3	26.8	28.4	29.9	28.5	27.9	28.2	27.3	26.3	24.7
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	5.1	7.9	7.7	7.7	7.4	6.7	6.2	5.9	5.7	5.4	4.7
40												
41												
42												

43 Notes: Bills include SUT
44 Each band represents a decile of customers segmented by annual load factor.

COMPARISON OF TYPICAL BILLS
Rate Schedule LPL-Primary
Including Tax Adjustment Credit and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	2,714	1,100	2,811	4,768	7,573	10,236	14,038	19,799	25,940	35,106	57,845
3	Distrib. KW Summer	963	165	494	859	1,346	1,883	2,523	3,796	4,772	6,480	10,839
4	Distribution kWhr On Peak June-September	181,334	20,156	67,741	130,817	204,213	335,781	498,004	752,300	1,045,259	1,559,226	2,988,621
5	Distribution kWhr Off Peak June-September	195,549	20,326	66,030	127,966	200,581	333,081	482,184	754,173	1,018,973	1,544,192	2,895,629
6	Distribution kWhr On Peak October-May	356,006	46,689	130,894	238,866	368,645	575,666	826,909	1,189,320	1,649,063	2,332,737	4,409,388
7	Distribution kWhr Off Peak October-May	354,467	57,709	144,733	263,185	425,957	673,746	1,023,554	1,382,934	1,999,682	3,007,330	5,579,838
8	Total	1,087,356	144,880	409,398	760,834	1,199,396	1,918,274	2,830,651	4,078,727	5,712,977	8,443,485	15,873,475
9												
10	Gen Cap Obl June-September	292	69	271	433	822	1,223	1,779	3,203	3,906	5,459	10,838
11	Gen Cap Obl October-May	591	137	541	866	1,644	2,445	3,559	6,407	7,812	10,917	21,675
12	Trans Cap Obl	764	206	812	1,298	2,465	3,668	5,338	9,610	11,718	16,376	32,513
13												
14												
15	**Present Bill**											
16	Total Delivery	$38,150.11	$10,632.94	$21,669.17	$35,048.10	$52,701.67	$75,548.62	$104,888.19	$150,003.75	$199,659.66	$281,405.50	$497,023.39
17	Total Supply	110,250.04	16,841.52	53,475.31	94,514.54	158,993.33	248,068.93	364,138.83	572,459.44	759,148.06	1,100,241.99	2,110,817.32
18	Totals	$148,400.15	$27,474.46	$75,144.48	$129,562.64	$211,695.00	$323,617.55	$469,027.02	$722,463.19	$958,807.72	$1,381,647.49	$2,607,840.71
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$46,218.64	$12,851.83	$27,655.37	$45,319.17	$68,934.24	$97,873.75	$135,342.30	$193,969.45	$256,587.69	$358,826.81	$626,068.41
24	Total Supply	110,250.04	16,841.52	53,475.31	94,514.54	158,993.33	248,068.93	364,138.83	572,459.44	759,148.06	1,100,241.99	2,110,817.32
25	Totals	$156,468.68	$29,693.35	$81,130.68	$139,833.71	$227,927.57	$345,942.68	$499,481.13	$766,428.89	$1,015,735.75	$1,459,068.80	$2,736,885.73
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$8,068.53	$2,218.89	$5,986.20	$10,271.07	$16,232.57	$22,325.13	$30,454.11	$43,965.70	$56,928.03	$77,421.31	$129,045.02
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$8,068.53	$2,218.89	$5,986.20	$10,271.07	$16,232.57	$22,325.13	$30,454.11	$43,965.70	$56,928.03	$77,421.31	$129,045.02
33												
34												
35												
36	**Increase Percent**											
37	Delivery	21.1	20.9	27.6	29.3	30.8	29.6	29.0	29.3	28.5	27.5	26.0
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	5.4	8.1	8.0	7.9	7.7	6.9	6.5	6.1	5.9	5.6	4.9
40												
41												
42												

43 Notes: Bills include SUT
44 Each band represents a decile of customers segmented by annual load factor.
Assumes approval of 2023 TAC filing, plus proposed TAC and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule HTS-Subtransmission
Distribution Only

		Annual Usages										
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	8,510	16,016	33,517	43,054	53,114	64,352	92,050	118,125	126,668	205,192	304,897
3	Distrib. KW Summer	3,229	2,835	5,634	7,592	8,661	11,865	18,147	20,700	22,409	37,283	54,058
4	Distribution kWhr June-September/ On Peak	657,674	261,688	745,560	1,347,361	1,702,401	2,668,654	3,764,815	4,407,798	6,032,750	10,071,192	15,427,406
5	Spare/Distribution kWhr June-September Off Peak	802,348	245,371	716,258	1,294,689	1,697,360	2,581,557	3,537,903	4,076,519	5,732,295	9,604,244	14,878,490
6	Distribution kWhr October-May/ On Peak	1,119,467	460,351	1,284,320	2,422,003	3,059,030	4,074,529	4,889,331	6,818,869	9,162,160	15,671,095	24,184,459
7	Spare/Distribution kWhr October-May Off Peak	1,248,432	485,083	1,728,891	2,634,840	4,175,256	5,130,556	6,538,649	9,239,434	12,604,177	21,281,831	32,307,388
8	Total	3,827,922	1,452,493	4,475,029	7,698,893	10,634,047	14,455,295	18,730,698	24,542,620	33,531,382	56,628,362	86,797,743
9												
10	Gen Cap Obl June-September	640	777	1,993	4,850	5,444	9,776	12,896	12,947	19,450	31,425	43,055
11	Gen Cap Obl October-May	1,354	1,553	3,986	9,701	10,887	19,552	25,792	25,893	38,900	62,849	86,109
12	Trans Cap Obl	1,758	2,330	5,980	14,551	16,331	29,328	38,688	38,840	58,350	94,274	129,164
13												
14												
15	**Present Bill**											
16	Total Delivery	$116,395.40	$82,040.09	$168,892.49	$245,856.58	$314,459.91	$409,503.42	$546,185.87	$691,464.58	$867,499.60	$1,435,076.20	$2,161,257.69
17	Total Supply	353,899.62	172,454.63	500,704.46	966,148.04	1,239,488.66	1,867,441.66	2,445,176.37	2,899,684.75	4,091,793.58	6,804,248.93	10,063,410.29
18	Totals	$470,295.02	$254,494.72	$669,596.95	$1,212,004.62	$1,553,948.57	$2,276,945.08	$2,991,362.24	$3,591,149.33	$4,959,293.18	$8,239,325.13	$12,224,667.98
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$131,497.53	$101,692.69	$209,214.49	$298,611.17	$377,632.99	$489,754.70	$664,156.63	$835,853.23	$1,022,903.59	$1,689,474.14	$2,535,644.93
24	Total Supply	353,899.62	172,454.63	500,704.46	966,148.04	1,239,488.66	1,867,441.66	2,445,176.37	2,899,684.75	4,091,793.58	6,804,248.93	10,063,410.29
25	Totals	$485,397.15	$274,147.32	$709,918.95	$1,264,759.21	$1,617,121.65	$2,357,196.36	$3,109,333.00	$3,735,537.98	$5,114,697.17	$8,493,723.07	$12,599,055.22
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$15,102.13	$19,652.60	$40,322.00	$52,754.59	$63,173.08	$80,251.28	$117,970.76	$144,388.65	$155,403.99	$254,397.94	$374,387.24
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$15,102.13	$19,652.60	$40,322.00	$52,754.59	$63,173.08	$80,251.28	$117,970.76	$144,388.65	$155,403.99	$254,397.94	$374,387.24
33												
34												
35												
36	**Increase Percent**											
37	Delivery	13.0	24.0	23.9	21.5	20.1	19.6	21.6	20.9	17.9	17.7	17.3
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	3.2	7.7	6.0	4.4	4.1	3.5	3.9	4.0	3.1	3.1	3.1
40												
41												
42												
43	Notes:	Bills include SUT										
44		Each band represents a decile of customers segmented by annual load factor.										

COMPARISON OF TYPICAL BILLS
Rate Schedule HTS-Subtransmission
Including Tax Adjustment Credit and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Serv Chg	12	12	12	12	12	12	12	12	12	12	12
2	Distrib. KW Annual	8,510	16,016	33,517	43,054	53,114	64,352	92,050	118,125	126,668	205,192	304,897
3	Distrib. KW Summer	3,229	2,835	5,634	7,592	8,661	11,865	18,147	20,700	22,409	37,283	54,058
4	Distribution kWhr June-September/ On Peak	657,674	261,688	745,560	1,347,361	1,702,401	2,668,654	3,764,815	4,407,798	6,032,750	10,071,192	15,427,406
5	Spare/Distribution kWhr June-September Off Peak	802,348	245,371	716,258	1,294,689	1,697,360	2,581,557	3,537,903	4,076,519	5,732,295	9,604,244	14,878,490
6	Distribution kWhr October-May/ On Peak	1,119,467	460,351	1,284,320	2,422,003	3,059,030	4,074,529	4,889,331	6,818,869	9,162,160	15,671,095	24,184,459
7	Spare/Distribution kWhr October-May Off Peak	1,248,432	485,083	1,728,891	2,634,840	4,175,256	5,130,556	6,538,649	9,239,434	12,604,177	21,281,831	32,307,388
8	Total	3,827,922	1,452,493	4,475,029	7,698,893	10,634,047	14,455,295	18,730,698	24,542,620	33,531,382	56,628,362	86,797,743
9												
10	Gen Cap Obl June-September	640	777	1,993	4,850	5,444	9,776	12,896	12,947	19,450	31,425	43,055
11	Gen Cap Obl October-May	1,354	1,553	3,986	9,701	10,887	19,552	25,792	25,893	38,900	62,849	86,109
12	Trans Cap Obl	1,758	2,330	5,980	14,551	16,331	29,328	38,688	38,840	58,350	94,274	129,164
13												
14												
15	**Present Bill**											
16	Total Delivery	$116,395.40	$82,040.09	$168,892.49	$245,856.58	$314,459.91	$409,503.42	$546,185.87	$691,464.58	$867,499.60	$1,435,076.20	$2,161,257.69
17	Total Supply	353,899.62	172,454.63	500,704.46	966,148.04	1,239,488.66	1,867,441.66	2,445,176.37	2,899,684.75	4,091,793.58	6,804,248.93	10,063,410.29
18	Totals	$470,295.02	$254,494.72	$669,596.95	$1,212,004.62	$1,553,948.57	$2,276,945.08	$2,991,362.24	$3,591,149.33	$4,959,293.18	$8,239,325.13	$12,224,667.98
19												
20												
21												
22	**Proposed Bill**											
23	Total Delivery	$133,170.32	$102,327.43	$211,170.07	$301,975.59	$382,280.07	$496,071.67	$672,341.94	$846,578.35	$1,037,556.80	$1,714,220.73	$2,573,575.55
24	Total Supply	353,899.62	172,454.63	500,704.46	966,148.04	1,239,488.66	1,867,441.66	2,445,176.37	2,899,684.75	4,091,793.58	6,804,248.93	10,063,410.29
25	Totals	$487,069.94	$274,782.06	$711,874.53	$1,268,123.63	$1,621,768.73	$2,363,513.33	$3,117,518.31	$3,746,263.10	$5,129,350.38	$8,518,469.66	$12,636,985.84
26												
27												
28												
29	**Increase Amount**											
30	Delivery	$16,774.92	$20,287.34	$42,277.58	$56,119.01	$67,820.16	$86,568.25	$126,156.07	$155,113.77	$170,057.20	$279,144.53	$412,317.86
31	Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Totals	$16,774.92	$20,287.34	$42,277.58	$56,119.01	$67,820.16	$86,568.25	$126,156.07	$155,113.77	$170,057.20	$279,144.53	$412,317.86
33												
34												
35												
36	**Increase Percent**											
37	Delivery	14.4	24.7	25.0	22.8	21.6	21.1	23.1	22.4	19.6	19.5	19.1
38	Supply	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Totals	3.6	8.0	6.3	4.6	4.4	3.8	4.2	4.3	3.4	3.4	3.4
40												
41												
42												
43	Notes:	Bills include SUT										
44		Each band represents a decile of customers segmented by annual load factor.										
		Assumes approval of 2023 TAC filing, plus proposed TAC and DAC										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	S	**SUMMARY OF RESULTS**									
2	S	**DEVELOPMENT OF RETURN**									
3	S										
4	S	**RATE BASE**									
5	S	Plant in Service									
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0
8	S	Distribution Plant									
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	115,892,513	580,978	1,461,893	2,460	30	91,721	1,191,740
10	S	Station Equipment E362	CALCULATED	1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
13	S	UG Conductors E366	CALCULATED	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
15	S	Line Transformers E368	CALCULATED	1,591,690,631	731,076,335	3,630,886	9,191,170	15,115	185	577,148	7,322,506
16	S	Services E369	CALCULATED	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
17	S	Meters E370	CALCULATED	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
18	S	Street Lighting E373	CALCULATED	499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	40,728,315	202,697	512,421	847	10	32,171	1,172,548
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
22	S	General Plant E389-E399	CALCULATED	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
23	S	Common Plant C389-C399	CALCULATED	126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	66,821,708	343,194	1,154,805	1,256,176	5,431	115,567	1,791,287
25	S	Total Plant in Service	CALCULATED	11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553
26	S										
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
28	S	Plus: Rate Base Additions									
29	S	Working Capital	CALCULATED	1,153,424,258	490,302,202	2,523,636	10,845,013	12,360,766	53,195	428,875	49,523,457
30	S	Plant Held for Future Use	CALCULATED	495,177	194,903	1,192	8,878	15,035	64	156	17,969
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		2,015,996,645	1,116,247,266	5,089,440	26,349,177	39,164,724	172,199	625,417	49,587,070
33	S	Plus: Rate Base Deductions									
34	S	Customer Advances	CALCULATED	-63,735,780	-27,981,120	-149,569	-811,609	-1,169,221	-5,015	-24,017	-2,261,042
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,800,404,102	-711,001,005	-4,340,554	-32,143,955	-54,346,050	-231,054	-579,039	-64,933,224
37	S	Other Rate Base Deductions		-27,893,945	-11,652,051	-57,404	-146,069	-235	-3	-9,179	-135,780
38	S										
39	S	TOTAL RATE BASE		9,635,540,505	4,158,694,615	22,302,297	127,655,917	188,021,228	805,896	3,044,800	344,429,795
40	S										
41	S										
42	S										
43	S										
44	S										
45	S										
46	S										
47	S										
48	S										
49	S										
50	S	**SUMMARY OF RESULTS**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	S	**SUMMARY OF RESULTS**								
2	S	**DEVELOPMENT OF RETURN**								
3	S									
4	S	**RATE BASE**								
5	S	Plant in Service								
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0
8	S	Distribution Plant								
9	S	Land & Structures E360-E361	CALCULATED	64,418	578,502	62,421,674	70,570,214	19,334,206	21,380,266	0
10	S	Station Equipment E362	CALCULATED	343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
12	S	OH Conductors and Devices E365	CALCULATED	631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
13	S	UG Conductors E366	CALCULATED	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
14	S	UG Conduits and Devices E367	CALCULATED	330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
15	S	Line Transformers E368	CALCULATED	395,810	3,554,541	393,843,633	442,083,302	0	0	0
16	S	Services E369	CALCULATED	0	0	53,039,066	1,013,079	243,028	415	0
17	S	Meters E370	CALCULATED	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
18	S	Street Lighting E373	CALCULATED	7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
19	S	Asset Retirement Obligations E374	CALCULATED	22,181	369,481	21,940,150	24,666,626	3,655,063	3,210,016	0
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
22	S	General Plant E389-E399	CALCULATED	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
23	S	Common Plant C389-C399	CALCULATED	20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	20,849	1,121,837	25,501,178	19,025,068	3,822,878	4,367,181	1,576,735
25	S	Total Plant in Service	CALCULATED	2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514
26	S									
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
28	S	Plus: Rate Base Additions								
29	S	Working Capital	CALCULATED	630,826	20,235,366	252,329,018	234,457,248	48,180,493	29,765,847	1,788,317
30	S	Plant Held for Future Use	CALCULATED	99	6,923	106,278	110,882	20,190	12,456	154
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0
32	S	Other Rate Base Additions		277,762	19,045,598	366,626,788	303,175,825	55,400,795	34,088,269	146,315
33	S	Plus: Rate Base Deductions								
34	S	Customer Advances	CALCULATED	-25,009	-916,766	-13,168,864	-12,983,015	-2,491,582	-1,648,875	-100,077
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-358,016	-25,091,851	-385,876,081	-401,953,643	-73,211,295	-45,517,164	-821,173
37	S	Other Rate Base Deductions		-6,164	-118,215	-6,278,171	-7,003,715	-1,822,785	-664,174	0
38	S									
39	S	TOTAL RATE BASE		2,214,624	133,309,963	2,012,626,362	2,022,581,857	377,880,185	239,503,489	2,469,479
40	S									
41	S									
42	S									
43	S									
44	S									
45	S									
46	S									
47	S									
48	S									
49	S									
50	S	**SUMMARY OF RESULTS**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED								
52	S										
53	S	**RATE BASE**	CALCULATED	9,635,540,505	4,158,694,615	22,302,297	127,655,917	188,021,228	805,896	3,044,800	344,429,795
54	S										
55	S	**OPERATING REVENUES**									
56	S	Rate Revenues from Customers	CALCULATED	1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
57	S	Other Operating Revenues	CALCULATED	25,104,439	9,399,091	50,241	272,626	392,751	1,685	10,900	759,503
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		1,887,985,784	827,236,523	4,421,864	23,994,492	34,566,954	148,276	712,878	66,845,666
61	S										
62	S	**OPERATING EXPENSES**									
63	S	Operation and Maintenance Expense									
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
67	S	Customer Accounts Expense	CALCULATED	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
68	S	Customer Service & Information Expense	CALCULATED	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
69	S	Sales Expense	CALCULATED	40,922	29,919	96	204	2	0	14	205
70	S	Administrative and General Expense	CALCULATED	33,695,393	9,187,244	94,796	1,392,549	2,753,608	11,635	-8,937	1,171,937
71	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	141,278,389	724,630	2,750,111	2,821,629	12,168	164,024	10,934,014
72	S	Depreciation Expense	CALCULATED	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
73	S	Amortization Expense	CALCULATED	21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
74	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
75	S	Proforma Expense Adjustments	CALCULATED	83,562,007	46,921,390	207,023	787,649	948,159	4,341	36,705	2,285,828
76	S	State Income Taxes	CALCULATED	116,400,498	49,105,403	269,701	1,621,455	2,453,615	10,492	36,040	4,221,229
77	S	Federal Income Taxes	CALCULATED	224,324,936	95,250,662	517,630	3,035,496	4,521,220	19,350	69,183	8,139,465
78	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		1,176,882,895	520,324,860	2,775,955	14,573,485	20,690,988	88,801	488,171	41,426,747
82	S										
83	S	**OPERATING INCOME (RETURN)**		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919
86	S										
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S										
90	S	**EQUALIZED RETURN AT PROPOSED ROR**									
91	S										
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**									
93	S										
94	S	**RATE BASE**	CALCULATED	9,635,540,505	4,158,694,615	22,302,297	127,655,917	188,021,228	805,896	3,044,800	344,429,795
95	S										
96	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
97	S										
98	S	**RETURN (RATE BASE * 7.40% ROR)**		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919
99	S	**PLUS:**	CALCULATED								
100	S	**OPERATING EXPENSES**									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	S	**DEVELOPMENT OF RETURN**	CALCULATED							
52	S									
53	S	**RATE BASE**	CALCULATED	2,214,624	133,309,963	2,012,626,362	2,022,581,857	377,880,185	239,503,489	2,469,479
54	S									
55	S	**OPERATING REVENUES**								
56	S	Rate Revenues from Customers	CALCULATED	730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
57	S	Other Operating Revenues	CALCULATED	8,401	416,062	5,976,509	5,892,164	1,130,770	748,319	45,419
58	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
59	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0
60	S	TOTAL OPERATING REVENUES		739,355	27,211,460	390,878,529	385,362,162	73,955,188	48,941,952	2,970,485
61	S									
62	S	**OPERATING EXPENSES**								
63	S	Operation and Maintenance Expense								
64	S	Production Expense	CALCULATED	0	0	0	0	0	0	0
65	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0
66	S	Distribution Expense	CALCULATED	377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
67	S	Customer Accounts Expense	CALCULATED	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
68	S	Customer Service & Information Expense	CALCULATED	214	34,498	876,964	140,606	11,945	3,040	367
69	S	Sales Expense	CALCULATED	4	555	9,167	677	61	17	1
70	S	Administrative and General Expense	CALCULATED	14,444	368,183	10,016,153	6,470,623	1,906,111	749,804	-432,758
71	S	Total Operation and Maintenance Expense	CALCULATED	406,726	5,323,015	65,767,731	56,873,087	13,274,358	9,692,791	1,434,962
72	S	Depreciation Expense	CALCULATED	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
73	S	Amortization Expense	CALCULATED	3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
74	S	Taxes Other Than Income Taxes	CALCULATED	-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
75	S	Proforma Expense Adjustments	CALCULATED	10,712	936,640	14,603,278	12,676,955	2,272,343	1,620,651	250,332
76	S	State Income Taxes	CALCULATED	26,005	1,627,834	24,487,235	24,966,650	4,640,740	2,918,281	15,819
77	S	Federal Income Taxes	CALCULATED	50,676	3,138,183	47,100,886	47,914,556	8,925,258	5,619,149	23,222
78	S	Provision for Deferred Income Taxes	CALCULATED	23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
79	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
80	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
81	S	TOTAL OPERATING EXPENSES		575,916	17,373,185	242,346,704	236,095,621	46,067,630	31,266,595	2,788,238
82	S									
83	S	**OPERATING INCOME (RETURN)**		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248
84	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0
85	S	TOTAL NET OPERATING INCOME		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248
86	S									
87	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
88	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00
89	S									
90	S	**EQUALIZED RETURN AT PROPOSED ROR**								
91	S									
92	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**								
93	S									
94	S	**RATE BASE**	CALCULATED	2,214,624	133,309,963	2,012,626,362	2,022,581,857	377,880,185	239,503,489	2,469,479
95	S									
96	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
97	S									
98	S	**RETURN (RATE BASE * 7.40% ROR)**		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248
99	S	**PLUS:**	CALCULATED							
100	S	**OPERATING EXPENSES**								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	141,278,389	724,630	2,750,111	2,821,629	12,168	164,024	10,934,014
102	S	Depreciation Expense	CALCULATED	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
103	S	Amortization Expense	CALCULATED	21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
104	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
105	S	Proforma Expense Adjustments	CALCULATED	83,562,007	46,921,390	207,023	787,649	948,159	4,341	36,705	2,285,828
106	S	Income Taxes	CALCULATED	340,725,434	144,356,065	787,332	4,656,951	6,974,835	29,842	105,222	12,360,694
107	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		1,176,882,895	520,324,860	2,775,955	14,573,485	20,690,988	88,801	488,171	41,426,747
111	S										
112	S	**EQUALS TOTAL COST OF SERVICE**		1,887,985,784	827,236,523	4,421,864	23,994,492	34,566,954	148,276	712,878	66,845,666
113	S										
114	S	**LESS:**									
115	S	Other Operating Revenues	CALCULATED	25,104,439	9,399,091	50,241	272,626	392,751	1,685	10,900	759,503
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0
118	S	**EQUALS:**									
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
120	S										
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	S	Total Operation and Maintenance Expense	CALCULATED	406,726	5,323,015	65,767,731	56,873,087	13,274,358	9,692,791	1,434,962
102	S	Depreciation Expense	CALCULATED	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
103	S	Amortization Expense	CALCULATED	3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
104	S	Taxes Other Than Income Taxes	CALCULATED	-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
105	S	Proforma Expense Adjustments	CALCULATED	10,712	936,640	14,603,278	12,676,955	2,272,343	1,620,651	250,332
106	S	Income Taxes	CALCULATED	76,681	4,766,016	71,588,121	72,881,206	13,565,998	8,537,430	39,041
107	S	Provision for Deferred Income Taxes	CALCULATED	23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
108	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0
109	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0
110	S	**TOTAL OPERATING EXPENSES**		575,916	17,373,185	242,346,704	236,095,621	46,067,630	31,266,595	2,788,238
111	S									
112	S	**EQUALS TOTAL COST OF SERVICE**		739,355	27,211,460	390,878,529	385,362,162	73,955,188	48,941,952	2,970,485
113	S									
114	S	**LESS:**								
115	S	Other Operating Revenues	CALCULATED	8,401	416,062	5,976,509	5,892,164	1,130,770	748,319	45,419
116	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0
117	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0
118	S	**EQUALS:**								
119	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
120	S									
121	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0
122	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBP	**DEVELOPMENT OF RATE BASE**									
2	RBP										
3	RBP	**ELECTRIC PLANT IN SERVICE**									
4	RBP										
5	RBP	PRODUCTION PLANT									
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0
9	RBP										
10	RBP	TRANSMISSION PLANT									
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
17	RBP										
18	RBP	DISTRIBUTION PLANT									
19	RBP	E360-E361 Land & Structures									
20	RBP	E360 - Land and Land Rights									
21	RBP	- Headquarters related	E362PLT	14,080,608	5,558,584	27,866	70,117	118	1	4,399	57,160
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	14,698,647	73,685	185,412	312	4	11,633	151,148
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0	0
26	RBP	- Headquarters related	E362PLT	124,204,880	49,032,209	245,802	618,503	1,041	13	38,805	504,205
27	RBP	- Substation related	E362PLT	118,051,566	46,603,073	233,625	587,861	989	12	36,883	479,226
28	RBP	Total Accounts E360-E361		293,570,614	115,892,513	580,978	1,461,893	2,460	30	91,721	1,191,740
29	RBP	E362 - Station Equipment									
30	RBP	Switching Stations - Energy Related - System		269,637,863	64,688,814	441,813	922,235	2,764	34	56,190	1,339,094
31	RBP	Switching Stations - Demand Related - System		68,805,545	27,072,878	87,168	297,615	0	0	19,363	0
32	RBP	H Class Substations - Energy Related - System		626,002,523	242,296,289	1,654,839	3,454,295	10,354	127	210,463	5,015,667
33	RBP	H Class Substations - Demand Related - System		600,972,238	283,920,236	914,150	3,121,164	0	0	203,070	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0	0
36	RBP	Total Account E362		1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
37	RBP	E364 - Poles Towers & Fixtures									
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	0	0	0	0	0	0	8,114,160
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	0	0	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		80,822,343	19,390,087	132,431	276,435	829	10	16,843	401,386
42	RBP	Subtransmission lines - Demand Related - System		20,624,052	8,114,934	26,128	89,208	0	0	5,804	0
43	RBP	Primary Lines - Energy Related - Local		123,061,406	47,631,313	325,313	679,055	2,035	25	41,373	985,995
44	RBP	Primary Lines - Energy Related - System		123,061,406	47,631,313	325,313	679,055	2,035	25	41,373	985,995
45	RBP	Primary Lines - Demand Related - Local		118,140,880	55,813,870	179,706	613,567	0	0	39,920	0
46	RBP	Primary Lines - Demand Related - System		118,140,880	55,813,870	179,706	613,567	0	0	39,920	0
47	RBP	Secondary Lines - Energy Related - Local		227,674,404	96,377,143	658,238	1,374,000	4,118	50	83,715	1,995,060
48	RBP	Secondary Lines - Demand Related - Local		205,991,127	102,808,931	331,018	1,130,189	0	0	73,532	0
49	RBP	Total Account E364		1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
50	RBP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBP	**DEVELOPMENT OF RATE BASE**								
2	RBP									
3	RBP	**ELECTRIC PLANT IN SERVICE**								
4	RBP									
5	RBP	PRODUCTION PLANT								
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0
9	RBP									
10	RBP	TRANSMISSION PLANT								
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
17	RBP									
18	RBP	DISTRIBUTION PLANT								
19	RBP	E360-E361 Land & Structures								
20	RBP	E360 - Land and Land Rights								
21	RBP	- Headquarters related	E362PLT	3,090	27,747	2,993,948	3,384,778	927,332	1,025,468	0
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	8,170	73,371	7,916,941	8,950,420	2,452,157	2,711,659	0
25	RBP	E361 - Structures and improvements		0	0	0	0	0	0	0
26	RBP	- Headquarters related	E362PLT	27,254	244,755	26,409,580	29,857,093	8,179,983	9,045,637	0
27	RBP	- Substation related	E362PLT	25,904	232,629	25,101,206	28,377,923	7,774,733	8,597,502	0
28	RBP	Total Accounts E360-E361		64,418	578,502	62,421,674	70,570,214	19,334,206	21,380,266	0
29	RBP	E362 - Station Equipment								
30	RBP	Switching Stations - Energy Related - System		72,383	650,032	34,588,792	50,054,033	14,315,393	102,506,285	0
31	RBP	Switching Stations - Demand Related - System		0	0	14,686,720	12,080,305	3,060,947	11,500,549	0
32	RBP	H Class Substations - Energy Related - System		271,117	2,434,739	129,554,637	187,480,734	53,619,263	0	0
33	RBP	H Class Substations - Demand Related - System		0	0	154,023,408	126,689,266	32,100,944	0	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0
36	RBP	Total Account E362		343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
37	RBP	E364 - Poles Towers & Fixtures								
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	0	0	0	0	0	0	0
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	0	1,812,825	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		21,696	194,843	10,367,784	15,003,398	4,290,954	30,725,648	0
42	RBP	Subtransmission lines - Demand Related - System		0	0	4,402,257	3,620,999	917,501	3,447,221	0
43	RBP	Primary Lines - Energy Related - Local		53,297	478,628	25,468,229	36,855,511	10,540,632	0	0
44	RBP	Primary Lines - Energy Related - System		53,297	478,628	25,468,229	36,855,511	10,540,632	0	0
45	RBP	Primary Lines - Demand Related - Local		0	0	30,278,372	24,904,946	6,310,497	0	0
46	RBP	Primary Lines - Demand Related - System		0	0	30,278,372	24,904,946	6,310,497	0	0
47	RBP	Secondary Lines - Energy Related - Local		107,841	968,456	51,532,386	74,573,398	0	0	0
48	RBP	Secondary Lines - Demand Related - Local		0	0	55,772,643	45,874,814	0	0	0
49	RBP	Total Account E364		236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
50	RBP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBP										
52	RBP										
53	RBP										
54	RBP										
55	RBP										
56	RBP										
57	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
58	RBP										
59	RBP	DISTRIBUTION PLANT CONTINUED									
60	RBP	E365 - OH Conductors and Devices									
61	RBP	Direct - BPL	DIR_BPL_02	2,226,625	0	0	0	0	0	0	2,226,625
62	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	0	0	0	0	0	0	0
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
64	RBP	Subtransmission lines - Energy Related - System		160,845,181	38,588,364	263,551	550,135	1,649	20	33,519	798,801
65	RBP	Subtransmission lines - Demand Related - System		41,044,089	16,149,594	51,998	177,534	0	0	11,551	0
66	RBP	Primary lines - Energy Related - Local		643,665,448	249,132,781	1,701,531	3,551,759	10,646	130	216,401	5,157,186
67	RBP	Primary lines - Energy Related - System		643,665,448	249,132,781	1,701,531	3,551,759	10,646	130	216,401	5,157,186
68	RBP	Primary lines - Demand Related - Local		617,928,923	291,931,165	939,943	3,209,229	0	0	208,799	0
69	RBP	Primary lines - Demand Related - System		617,928,923	291,931,165	939,943	3,209,229	0	0	208,799	0
70	RBP	Secondary lines -Energy Related - Local		64,282,796	27,211,633	185,850	387,942	1,163	14	23,636	563,296
71	RBP	Secondary lines -Demand Related - Local		58,160,625	29,027,618	93,461	319,104	0	0	20,762	0
72	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0
73	RBP	Total Account E365		2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
74	RBP										
75	RBP	E366 - Underground Conduit									
76	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
77	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
78	RBP	Underground Conduits	E367PLT	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
79	RBP	Not Used	not_used								
80	RBP	Total Account E366		512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
81	RBP										
82	RBP	E367 - Underground Conductors & Devices									
83	RBP	Direct - BPL	DIR_BPL_02	2,325,498	0	0	0	0	0	0	2,325,498
84	RBP	Direct - PSAL	DIR_PSAL_02	868,520	0	0	0	0	0	0	0
85	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	1,525,824	9,591	74,133	126,809	538	1,204	151,403
86	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
87	RBP	367.1 - Conventional UG									
88	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	40,943,727	9,822,809	67,088	140,039	420	5	8,532	203,338
89	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	10,447,922	4,110,938	13,236	45,192	0	0	2,940	0
90	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	90,324,112	34,960,238	238,772	498,410	1,494	18	30,367	723,696
91	RBP	Primary lines - Energy Related - System	KWH_PRI_09	90,324,112	34,960,238	238,772	498,410	1,494	18	30,367	723,696
92	RBP	Primary lines - Demand Related - Local	CP_PRI_04	86,712,563	40,966,038	131,900	450,344	0	0	29,300	0
93	RBP	Primary lines - Demand Related - System	CP_PRI_05	86,712,563	40,966,038	131,900	450,344	0	0	29,300	0
94	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	283,098,081	119,838,610	818,476	1,708,478	5,121	63	104,094	2,480,726
95	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	256,136,359	127,836,114	411,599	1,405,315	0	0	91,433	0
96	RBP	367.2 - BUD									
97	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	381,867	91,614	626	1,306	4	0	80	1,896
98	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	97,444	38,341	123	421	0	0	27	0
99	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	114,385,571	44,273,303	302,379	631,182	1,892	23	38,457	916,482
100	RBP	Primary lines - Energy Related - System	KWH_PRI_09	114,385,571	44,273,303	302,379	631,182	1,892	23	38,457	916,482

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBP									
52	RBP									
53	RBP									
54	RBP									
55	RBP									
56	RBP									
57	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
58	RBP									
59	RBP	DISTRIBUTION PLANT CONTINUED								
60	RBP	E365 - OH Conductors and Devices								
61	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
62	RBP	Direct - PSAL	DIR_PSAL_02	0	6,436,532	0	0	0	0	0
63	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
64	RBP	Subtransmission lines - Energy Related - System		43,178	387,759	20,633,009	29,858,381	8,539,461	61,147,355	0
65	RBP	Subtransmission lines - Demand Related - System		0	0	8,760,966	7,206,179	1,825,926	6,860,342	0
66	RBP	Primary lines - Energy Related - Local		278,766	2,503,436	133,210,076	192,770,582	55,132,153	0	0
67	RBP	Primary lines - Energy Related - System		278,766	2,503,436	133,210,076	192,770,582	55,132,153	0	0
68	RBP	Primary lines - Demand Related - Local		0	0	158,369,244	130,263,857	33,006,686	0	0
69	RBP	Primary lines - Demand Related - System		0	0	158,369,244	130,263,857	33,006,686	0	0
70	RBP	Secondary lines -Energy Related - Local		30,448	273,439	14,549,926	21,055,448	0	0	0
71	RBP	Secondary lines -Demand Related - Local		0	0	15,747,143	12,952,538	0	0	0
72	RBP	Other	DISTPLT	0	0	0	0	0	0	0
73	RBP	Total Account E365		631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
74	RBP									
75	RBP	E366 - Underground Conduit								
76	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
77	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
78	RBP	Underground Conduits	E367PLT	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
79	RBP	Not Used	not_used							
80	RBP	Total Account E366		118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
81	RBP									
82	RBP	E367 - Underground Conductors & Devices								
83	RBP	Direct - BPL	DIR_BPL_02	0	0	0	0	0	0	0
84	RBP	Direct - PSAL	DIR_PSAL_02	0	868,520	0	0	0	0	0
85	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	822	57,999	842,202	921,717	165,685	101,534	0
86	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
87	RBP	367.1 - Conventional UG								
88	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	10,991	98,706	5,252,208	7,600,560	2,173,751	15,565,282	0
89	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	0	0	2,230,136	1,834,359	464,796	1,746,325	0
90	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	39,119	351,302	18,693,068	27,051,058	7,736,570	0	0
91	RBP	Primary lines - Energy Related - System	KWH_PRI_09	39,119	351,302	18,693,068	27,051,058	7,736,570	0	0
92	RBP	Primary lines - Demand Related - Local	CP_PRI_04	0	0	22,223,597	18,279,631	4,631,753	0	0
93	RBP	Primary lines - Demand Related - System	CP_PRI_05	0	0	22,223,597	18,279,631	4,631,753	0	0
94	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	134,093	1,204,211	64,077,117	92,727,094	0	0	0
95	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	0	0	69,349,597	57,042,301	0	0	0
96	RBP	367.2 - BUD								
97	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	103	921	48,985	70,888	20,274	145,172	0
98	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	0	0	20,800	17,108	4,335	16,287	0
99	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	49,539	444,885	23,672,718	34,257,196	9,797,516	0	0
100	RBP	Primary lines - Energy Related - System	KWH_PRI_09	49,539	444,885	23,672,718	34,257,196	9,797,516	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	RBP	Primary lines - Demand Related - Local	CP_PRI_04	109,811,942	51,878,990	167,037	570,311	0	0	37,106	0
102	RBP	Primary lines - Demand Related - System	CP_PRI_05	109,811,942	51,878,990	167,037	570,311	0	0	37,106	0
103	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	15,979,016	6,764,098	46,198	96,432	289	4	5,875	140,021
104	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	14,457,205	7,215,504	23,232	79,321	0	0	5,161	0
105	RBP	Other	E367PLT	0	0	0	0	0	0	0	0
106	RBP	Total Account E367		1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
107	RBP										
108	RBP	E368 - Line Transformers									
109	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	835,637,581	353,734,812	2,415,944	5,043,017	15,115	185	307,260	7,322,506
110	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	756,053,050	377,341,523	1,214,942	4,148,153	0	0	269,888	0
111	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
112	RBP	Total Account E368		1,591,690,631	731,076,335	3,630,886	9,191,170	15,115	185	577,148	7,322,506
113	RBP	E369 - Services									
114	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
115	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0
116	RBP	Total Account E369		535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
117	RBP										
118	RBP										
119	RBP										
120	RBP										
121	RBP										
122	RBP										
123	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0	0
124	RBP										
125	RBP	E370 - Meters		0	0	0	0	0	0	0	0
126	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0
127	RBP	Customer Component	METERSMIN_07	76,316,914	44,092,057	153,180	255,919	171,335	2,673	17,398	0
128	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	122,177,671	74,077,186	257,350	429,959	0	0	29,229	0
129	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	166,926,857	101,208,934	351,608	587,437	0	0	39,935	0
130	RBP	Total Account E370		365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
131	RBP										
132	RBP	E373 - Street Lighting & Signal Systems									
133	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	0	0	0	0	0	0	340,539,607
134	RBP	PSAL luminaires & poles	DIR_PSAL_02	122,261,652	0	0	0	0	0	0	0
135	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	36,225,893	13,889,907	87,308	674,847	1,154,367	4,901	10,958	1,378,255
136	RBP	Total Account E373		499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
137	RBP										
138	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	40,728,315	202,697	512,421	847	10	32,171	1,172,548
139	RBP										
140	RBP	Other Distribution and Unallocated Plant									
141	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
142	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0
143	RBP										
144	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
145	RBP										
146	RBP	GENERAL AND COMMON PLANT									
147	RBP	E390-E398 GENERAL PLANT									
148	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0
149	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
150	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	RBP	Primary lines - Demand Related - Local	CP_PRI_04	0	0	28,143,745	23,149,146	5,865,607	0	0
102	RBP	Primary lines - Demand Related - System	CP_PRI_05	0	0	28,143,745	23,149,146	5,865,607	0	0
103	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	7,569	67,970	3,616,730	5,233,832	0	0	0
104	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	0	0	3,914,326	3,219,661	0	0	0
105	RBP	Other	E367PLT	0	0	0	0	0	0	0
106	RBP	Total Account E367		330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
107	RBP									
108	RBP	E368 - Line Transformers								
109	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	395,810	3,554,541	189,140,269	273,708,123	0	0	0
110	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	0	0	204,703,364	168,375,179	0	0	0
111	RBP	Not Used	not_used	0	0	0	0	0	0	0
112	RBP	Total Account E368		395,810	3,554,541	393,843,633	442,083,302	0	0	0
113	RBP	E369 - Services								
114	RBP	Basic portion (minimum size)	SERVICESMIN_03	0	0	53,039,066	1,013,079	243,028	415	0
115	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0
116	RBP	Total Account E369		0	0	53,039,066	1,013,079	243,028	415	0
117	RBP									
118	RBP									
119	RBP									
120	RBP									
121	RBP									
122	RBP									
123	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**		0	0	0	0	0	0	0
124	RBP									
125	RBP	E370 - Meters		0	0	0	0	0	0	0
126	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0
127	RBP	Customer Component	METERSMIN_07	0	0	26,382,336	2,862,678	747,318	1,330,366	301,654
128	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	0	0	37,265,374	6,277,875	3,206,344	634,354	0
129	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	0	0	50,914,309	8,577,230	4,380,709	866,694	0
130	RBP	Total Account E370		0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
131	RBP									
132	RBP	E373 - Street Lighting & Signal Systems								
133	RBP	BPL luminaires & poles	DIR_BPL_02	0	0	0	0	0	0	0
134	RBP	PSAL luminaires & poles	DIR_PSAL_02	0	122,261,652	0	0	0	0	0
135	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	7,483	527,976	7,666,746	8,390,589	1,508,270	924,286	0
136	RBP	Total Account E373		7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
137	RBP									
138	RBP	E374 - Asset Retirement Obligations	E364PLT	22,181	369,481	21,940,150	24,666,626	3,655,063	3,210,016	0
139	RBP									
140	RBP	Other Distribution and Unallocated Plant								
141	RBP	Not Used	not_used	0	0	0	0	0	0	0
142	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0
143	RBP									
144	RBP	TOTAL DISTRIBUTION PLANT		2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
145	RBP									
146	RBP	GENERAL AND COMMON PLANT								
147	RBP	E390-E398 GENERAL PLANT								
148	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0
149	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
150	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
152	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
153	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0
154	RBP	Total Accounts E390-E398		429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
155	RBP										
156	RBP	C389-C399 COMMON PLANT									
157	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
158	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
159	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0	0
160	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0
161	RBP	Customer Service Related	CUSTSVSX	92,605,476	54,634,469	263,469	450,786	8,905	135	110,692	324,063
162	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	12,936,216	81,313	628,511	1,075,107	4,564	10,206	1,283,623
163	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
164	RBP	Unassigned	COMPLT	309,972	165,778	846	2,648	2,660	12	297	3,944
165	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
166	RBP	Total Accounts C389-C399		126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
167	RBP										
168	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	232,449,865	1,380,965	9,084,615	14,775,729	62,826	251,142	17,955,662
169	RBP										
170	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**									
171	RBP										
172	RBP	INTANGIBLE PLANT - E301-E303									
173	RBP	Customer Service Related	TOTPLT	40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
174	RBP	Not Used	not_used	0	0	0	0	0	0	0	0
175	RBP	TOTAL INTANGIBLE PLANT		40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
176	RBP										
177	RBP	C303 - INTANGIBLE PLANT									
178	RBP	- Customer Related - Measurement	MRCOST_07	606,400	477,370	1,658	2,771	32	0	38	0
179	RBP	- Demand Related - Measurement	NCP_MTR_07	606,400	249,462	1,890	3,270	70	1	1,457	3,721
180	RBP	Customer Service Related	CUSTSVSX	84,635,615	49,932,488	240,794	411,990	8,138	124	101,166	296,174
181	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
182	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
183	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
184	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	188,090	1,182	9,138	15,632	66	148	18,664
185	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	50,847,410	245,525	427,169	23,872	192	102,808	318,558
186	RBP										
187	RBP	TOTAL INTANGIBLE PLANT		126,923,895	66,821,708	343,194	1,154,805	1,256,176	5,431	115,567	1,791,287
188	RBP										
189	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	RBP	Distribution Delivery	DISTPLTXMTR	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
152	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
153	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0
154	RBP	Total Accounts E390-E398		88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
155	RBP									
156	RBP	C389-C399 COMMON PLANT								
157	RBP	Not Used	not_used	0	0	0	0	0	0	0
158	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
159	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0
160	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0
161	RBP	Customer Service Related	CUSTSVSX	13,643	596,860	17,987,297	10,617,734	2,317,408	3,594,027	1,685,988
162	RBP	Distribution Delivery Related	DISTPLTXMTR	6,969	491,725	7,140,342	7,814,485	1,404,711	860,824	
163	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
164	RBP	Unassigned	COMPLT	51	2,671	61,648	45,222	9,132	10,930	4,136
165	RBP	Not Used	not_used	0	0	0	0	0	0	0
166	RBP	Total Accounts C389-C399		20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
167	RBP									
168	RBP	TOTAL GENERAL AND COMMON PLANT		109,399	7,352,255	116,105,365	117,977,206	21,617,058	15,426,426	1,690,125
169	RBP									
170	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**								
171	RBP									
172	RBP	INTANGIBLE PLANT - E301-E303								
173	RBP	Customer Service Related	TOTPLT	8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
174	RBP	Not Used	not_used	0	0	0	0	0	0	0
175	RBP	TOTAL INTANGIBLE PLANT		8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
176	RBP									
177	RBP	C303 - INTANGIBLE PLANT								
178	RBP	- Customer Related - Measurement	MRCOST_07	0	0	116,981	6,824	568	140	19
179	RBP	- Demand Related - Measurement	NCP_MTR_07	201	1,806	130,510	112,721	29,173	48,931	23,188
180	RBP	Customer Service Related	CUSTSVSX	12,469	545,493	16,439,265	9,703,945	2,117,966	3,284,716	1,540,888
181	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
182	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
183	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
184	RBP	E399.1 Asset Retirement Obligations	GENPLT	101	7,150	103,819	113,621	20,424	12,516	
185	RBP	TOTAL ACCOUNTS C303-C390.4,E399		12,772	554,449	16,790,575	9,937,110	2,168,131	3,346,303	1,564,094
186	RBP									
187	RBP	TOTAL INTANGIBLE PLANT		20,849	1,121,837	25,501,178	19,025,068	3,822,878	4,367,181	1,576,735
188	RBP									
189	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**									
2	RBD										
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE									
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	9,296,738	44,833	76,707	1,515	23	18,836	55,143
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	9,296,738	44,833	76,707	1,515	23	18,836	55,143
8	RBD										
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0
11	RBD										
12	RBD	DISTRIBUTION PLANT RESERVE									
13	RBD	E360-E361 Land & Structures - Reserve									
14	RBD	E360 - Land and Land Rights									
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	263,663	1,322	3,326	6	0	209	2,711
19	RBD	E361 - Structures and improvements									
20	RBD	- Headquarters Related	DISTPLT	40,449,681	15,807,014	97,042	732,754	1,245,886	5,296	12,146	1,486,756
21	RBD	- Substation Related	E362PLT	36,319,499	14,337,804	71,876	180,860	304	4	11,347	147,438
22	RBD	Total Accounts E360-E361		77,437,073	30,408,481	170,240	916,940	1,246,196	5,300	23,702	1,636,905
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	110,256,197	552,722	1,390,795	2,340	29	87,260	1,133,781
24	RBD	E364 Poles Towers and Fixtures Rsrv									
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	84,426,066	420,173	1,062,201	1,756	21	66,687	2,430,585
27	RBD	E365 OH Conductors and Devices - Rsrv									
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	254,812,498	1,255,329	3,194,313	5,148	63	200,728	2,969,296
30	RBD	E366 UG Conduit - Rsrv									
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	112,150,237	554,135	1,416,969	25,161	125	88,400	1,549,100
33	RBD	E367 UG Conductors and Devices - Rsrv									
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	222,651,325	1,100,121	2,813,103	49,953	248	175,500	3,075,420
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	198,944,531	84,215,463	575,176	1,200,617	3,599	44	73,151	1,743,307
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	179,997,433	89,835,634	289,247	987,572	0	0	64,254	0
38	RBD	E369 Services - Rsrv									
39	RBD	Services	E369PLT	240,814,772	377,380	2,375,766	64,419,906	148,583,936	630,494	0	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		240,814,772	377,380	2,375,766	64,419,906	148,583,936	630,494	0	0
42	RBD	E370 Meters - Rsrv									
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	136,921,647	82,199,942	285,570	477,105	64,199	1,001	32,435	0
45	RBD	Total Account E370 Rsrv		136,921,647	82,199,942	285,570	477,105	64,199	1,001	32,435	0
46	RBD	E373 Street Lighting - Rsrv									
47	RBD	Streetlight fixtures	E373PLT	118,939,285	3,310,553	20,809	160,845	275,135	1,168	2,612	81,493,494
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	3,310,553	20,809	160,845	275,135	1,168	2,612	81,493,494
50	RBD										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**								
2	RBD									
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE								
4	RBD	Customer Service Related - Reserve	CUSTSVSX	2,322	101,563	3,060,763	1,806,740	394,336	611,569	286,892
5	RBD	Not Used	not_used	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		2,322	101,563	3,060,763	1,806,740	394,336	611,569	286,892
8	RBD									
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0
11	RBD									
12	RBD	DISTRIBUTION PLANT RESERVE								
13	RBD	E360-E361 Land & Structures - Reserve								
14	RBD	E360 - Land and Land Rights								
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	147	1,316	142,014	160,552	43,987	48,642	0
19	RBD	E361 - Structures and improvements								
20	RBD	- Headquarters Related	DISTPLT	8,072	569,540	8,700,417	9,117,648	1,658,297	1,007,680	1,133
21	RBD	- Substation Related	E362PLT	7,970	71,570	7,722,585	8,730,693	2,391,958	2,645,089	0
22	RBD	Total Accounts E360-E361		16,188	642,426	16,565,015	18,008,892	4,094,242	3,701,411	1,133
23	RBD	E362 Station Equipment - Rsrv	E362PLT	61,285	550,368	59,385,859	67,138,103	18,393,906	20,340,458	0
24	RBD	E364 Poles Towers and Fixtures Rsrv								
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	45,979	765,899	45,479,921	51,131,656	7,576,612	6,654,069	0
27	RBD	E365 OH Conductors and Devices - Rsrv								
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	134,797	2,585,191	137,293,968	153,160,520	39,861,522	14,524,463	0
30	RBD	E366 UG Conduit - Rsrv								
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	59,720	702,192	60,427,902	67,524,944	10,628,760	3,171,858	0
33	RBD	E367 UG Conductors and Devices - Rsrv								
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	118,561	1,394,058	119,967,222	134,056,947	21,101,226	6,297,074	0
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	94,233	846,248	45,029,595	65,163,099	0	0	0
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	0	0	48,734,781	40,085,944	0	0	0
38	RBD	E369 Services - Rsrv								
39	RBD	Services	E369PLT	0	0	23,861,988	455,779	109,337	187	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		0	0	23,861,988	455,779	109,337	187	0
42	RBD	E370 Meters - Rsrv								
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	0	0	42,925,835	6,638,767	3,122,849	1,060,917	113,028
45	RBD	Total Account E370 Rsrv		0	0	42,925,835	6,638,767	3,122,849	1,060,917	113,028
46	RBD	E373 Street Lighting - Rsrv								
47	RBD	Streetlight fixtures	E373PLT	1,783	29,265,964	1,827,310	1,999,832	359,484	220,297	0
48	RBD	Not used	not_used	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		1,783	29,265,964	1,827,310	1,999,832	359,484	220,297	0
50	RBD									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**									
52	RBD	Other Plant Unallocated - Reserve									
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0
56	RBD										
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
60	RBD										
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	1,074,643,776	7,599,288	78,040,366	150,257,422	638,494	814,728	96,031,887
62	RBD										
63	RBD	GENERAL AND COMMON PLANT RESERVE									
64	RBD	E390-E398 GENERAL PLANT - RESERVE									
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	59,977,131	376,998	2,914,014	4,984,600	21,161	47,318	5,951,356
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	59,977,131	376,998	2,914,014	4,984,600	21,161	47,318	5,951,356
72	RBD										
73	RBD	C389-C399 COMMON PLANT RESERVE									
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measurement	MRCOST_07	0	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	27,600,166	133,099	227,727	4,498	68	55,919	163,710
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	7,352,507	46,216	357,225	611,055	2,594	5,801	729,568
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	34,952,673	179,314	584,952	615,553	2,663	61,720	893,278
84	RBD										
85	RBD	C303 - INTANGIBLE PLANT									
86	RBD	- Customer Related - Measurement	MRCOST_07	311,743	245,410	853	1,424	16	0	19	0
87	RBD	- Demand Related - Measurement	NCP_MTR_07	311,743	128,246	972	1,681	36	1	749	1,913
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	27,475,024	132,495	226,695	4,478	68	55,666	162,968
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	188,090	1,182	9,138	15,632	66	148	18,664
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	28,036,770	135,502	238,938	20,162	135	56,582	183,544
94	RBD										
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
96	RBD										
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	3,302,584,420	19,235,556	123,554,483	191,996,209	816,510	2,602,586	312,631,345

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**								
52	RBD	Other Plant Unallocated - Reserve								
53	RBD	Not Used	not_used	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0
56	RBD									
57	RBD	Not Used	not_used	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0
60	RBD									
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		532,546	36,752,346	601,499,397	605,364,485	105,247,938	55,970,733	114,161
62	RBD									
63	RBD	GENERAL AND COMMON PLANT RESERVE								
64	RBD	E390-E398 GENERAL PLANT - RESERVE								
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	32,311	2,279,819	33,105,293	36,230,874	6,512,763	3,991,103	0
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		32,311	2,279,819	33,105,293	36,230,874	6,512,763	3,991,103	0
72	RBD									
73	RBD	C389-C399 COMMON PLANT RESERVE								
74	RBD	Not Used	not_used	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measurement	MRCOST_07	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	6,892	301,521	9,086,798	5,363,852	1,170,705	1,815,626	851,725
79	RBD	Distribution Delivery Related	DISTPLTXMTR	3,961	279,480	4,058,328	4,441,488	798,390	489,263	0
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		10,853	581,001	13,145,126	9,805,341	1,969,095	2,304,889	851,725
84	RBD									
85	RBD	C303 - INTANGIBLE PLANT								
86	RBD	- Customer Related - Measurement	MRCOST_07	0	0	60,139	3,508	292	72	10
87	RBD	- Demand Related - Measurement	NCP_MTR_07	103	929	67,094	57,949	14,997	25,155	11,920
88	RBD	Customer Service Related	CUSTSVSX	6,861	300,154	9,045,598	5,339,532	1,165,397	1,807,393	847,863
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	101	7,150	103,819	113,621	20,424	12,516	0
93	RBD	Total Accounts C303-C390.4,E399		7,066	308,232	9,276,649	5,514,609	1,201,111	1,845,136	859,793
94	RBD									
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
96	RBD									
97	RBD	**NET ELECTRIC PLANT IN SERVICE**		1,695,126	120,148,908	1,798,887,394	1,906,778,275	351,804,368	223,467,130	1,455,942

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
2	RBO										
3	RBO	**PLUS: ADDITIONS TO RATE BASE**									
4	RBO										
5	RBO	Working Capital									
6	RBO	Cash (lead/lag)	EXPENDITURES	925,712,100	393,505,406	2,025,413	8,703,961	9,920,470	42,693	344,205	39,746,401
7	RBO	Materials and Supplies	EXPENDITURES	227,211,892	96,584,141	497,128	2,136,348	2,434,935	10,479	84,484	9,755,576
8	RBO	Prepayments	EXPENDITURES	500,266	212,655	1,095	4,704	5,361	23	186	21,479
9	RBO	Working Funds	EXPENDITURES								
10	RBO	Total Working Capital		1,153,424,258	490,302,202	2,523,636	10,845,013	12,360,766	53,195	428,875	49,523,457
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,016,196,832	397,111,592	2,437,943	18,408,607	31,299,772	133,061	305,134	37,351,026
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	495,177	194,903	1,192	8,878	15,035	64	156	17,969
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	286,198,206	113,093,130	658,699	4,230,978	6,574,685	27,960	89,123	10,705,694
15	RBO	CEF-EC Adjustment	ECPRO_07	670,378,464	587,103,967	1,891,565	3,160,266	498,899	7,783	214,841	
16	RBO	CEF-EV Adjustment	TOTREV	43,223,143	18,938,576	101,233	549,325	791,368	3,395	16,320	1,530,350
17	RBO	TOTAL ADDITIONS TO RATE BASE		3,169,916,080	1,606,744,371	7,614,267	37,203,068	51,540,525	225,458	1,054,448	99,128,496
18	RBO										
19	RBO										
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**									
21	RBO										
22	RBO	Customer Advances for Construction	REVREQ	(63,735,780)	(27,981,120)	(149,569)	(811,609)	(1,169,221)	(5,015)	(24,017)	(2,261,042)
23	RBO	Unbilled Revenue	TOTREV								
24	RBO	IAP Adjustment	E365PLT	(27,893,945)	(11,652,051)	(57,404)	(146,069)	(235)	(3)	(9,179)	(135,780)
25	RBO	Deferred Income Taxes and Credits									
26	RBO	ADIT Test/Post year	TOTPLT								
27	RBO	Liberalized Depreciation	TOTPLT	(2,247,763)	(884,723)	(5,409)	(40,300)	(68,250)	(290)	(707)	(81,566)
28	RBO	Cost of Removal	TOTPLT	15,629,066	6,151,627	37,612	280,210	474,555	2,018	4,913	567,141
29	RBO	3% Investment Tax Credit	DISTPLT								
30	RBO	Computer Software	INTANGPLT								
31	RBO	Capitalized Interest	TOTPLTNET	312,066	123,315	718	4,613	7,169	30	97	11,673
32	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	2,520,600	14,681	94,299	146,535	623	1,986	238,607
33	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(1,820,476,207)	(718,911,824)	(4,388,156)	(32,482,778)	(54,906,059)	(233,435)	(585,329)	(65,669,079)
34	RBO	Total Deferred Income Taxes and Credits		(1,800,404,102)	(711,001,005)	(4,340,554)	(32,143,955)	(54,346,050)	(231,054)	(579,039)	(64,933,224)
35	RBO										
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,892,033,827)	(750,634,176)	(4,547,526)	(33,101,634)	(55,515,506)	(236,072)	(612,235)	(67,330,046)
37	RBO										
38	RBO										
39	RBO	**TOTAL RATE BASE**		9,635,540,505	4,158,694,615	22,302,297	127,655,917	188,021,228	805,896	3,044,800	344,429,795

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
2	RBO									
3	RBO	**PLUS: ADDITIONS TO RATE BASE**								
4	RBO									
5	RBO	Working Capital								
6	RBO	Cash (lead/lag)	EXPENDITURES	506,286	16,240,445	202,513,536	188,170,059	38,668,569	23,889,393	1,435,262
7	RBO	Materials and Supplies	EXPENDITURES	124,266	3,986,145	49,706,041	46,185,499	9,491,027	5,863,544	352,279
8	RBO	Prepayments	EXPENDITURES	274	8,777	109,441	101,689	20,897	12,910	776
9	RBO	Working Funds	EXPENDITURES							
10	RBO	Total Working Capital		630,826	20,235,366	252,329,018	234,457,248	48,180,493	29,765,847	1,788,317
11	RBO	Net Plant Adds - Distribution	DISTPLT	202,788	14,308,266	218,576,165	229,058,040	41,660,553	25,315,433	28,452
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	99	6,923	106,278	110,882	20,190	12,456	154
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	58,048	4,114,358	61,600,789	65,295,386	12,047,128	7,652,370	49,857
15	RBO	CEF-EC Adjustment	ECPRO_07			77,501,143				
16	RBO	CEF-EV Adjustment	TOTREV	16,927	622,973	8,948,690	8,822,399	1,693,114	1,120,467	68,006
17	RBO	TOTAL ADDITIONS TO RATE BASE		908,686	39,287,886	619,062,083	537,743,955	103,601,478	63,866,572	1,934,786
18	RBO									
19	RBO									
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**								
21	RBO									
22	RBO	Customer Advances for Construction	REVREQ	(25,009)	(916,766)	(13,168,864)	(12,983,015)	(2,491,582)	(1,648,875)	(100,077)
23	RBO	Unbilled Revenue	TOTREV							
24	RBO	IAP Adjustment	E365PLT	(6,164)	(118,215)	(6,278,171)	(7,003,715)	(1,822,785)	(664,174)	
25	RBO	Deferred Income Taxes and Credits								
26	RBO	ADIT Test/Post year	TOTPLT							
27	RBO	Liberalized Depreciation	TOTPLT	(447)	(31,424)	(482,430)	(503,329)	(91,647)	(56,541)	(700)
28	RBO	Cost of Removal	TOTPLT	3,111	218,499	3,354,413	3,499,730	637,235	393,135	4,868
29	RBO	3% Investment Tax Credit	DISTPLT							
30	RBO	Computer Software	INTANGPLT							
31	RBO	Capitalized Interest	TOTPLTNET	63	4,486	67,168	71,197	13,136	8,344	54
32	RBO	NJ Corporate Business Tax	TOTPLTNET	1,294	91,700	1,372,948	1,455,292	268,504	170,555	1,111
33	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(362,036)	(25,375,111)	(390,188,181)	(406,476,533)	(74,038,523)	(46,032,658)	(826,506)
34	RBO	Total Deferred Income Taxes and Credits		(358,016)	(25,091,851)	(385,876,081)	(401,953,643)	(73,211,295)	(45,517,164)	(821,173)
35	RBO									
36	RBO	TOTAL DEDUCTIONS TO RATE BASE		(389,188)	(26,126,832)	(405,323,116)	(421,940,373)	(77,525,662)	(47,830,213)	(921,250)
37	RBO									
38	RBO									
39	RBO	**TOTAL RATE BASE**		2,214,624	133,309,963	2,012,626,362	2,022,581,857	377,880,185	239,503,489	2,469,479

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	REV	**OPERATING REVENUES**									
2	REV										
3	REV	**SALES REVENUES**									
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
8	REV										
9	REV	**OTHER OPERATING REVENUES**									
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	0	0	0	0	0	2,800	0
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	9,399,091	50,241	272,626	392,751	1,685	8,100	759,503
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		25,104,439	9,399,091	50,241	272,626	392,751	1,685	10,900	759,503
15	REV										
16	REV	**OTHER REVENUE SOURCES**									
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0
20	REV										
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0
22	REV										
23	REV	**TOTAL OPERATING REVENUES**		1,887,985,784	827,236,523	4,421,864	23,994,492	34,566,954	148,276	712,878	66,845,666

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	REV	**OPERATING REVENUES**								
2	REV									
3	REV	**SALES REVENUES**								
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
5	REV	Not Used	not_used	0	0	0	0	0	0	0
6	REV	Not Used	not_used	0	0	0	0	0	0	0
7	REV	TOTAL SALES OF ELECTRICITY		730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
8	REV									
9	REV	**OTHER OPERATING REVENUES**								
10	REV	450-Forfeited Discounts	REVLATEP	0	106,884	1,535,333	1,513,665	290,489	192,239	11,668
11	REV	456-Other Electric Revenues	TOTREV	8,401	309,178	4,441,176	4,378,499	840,281	556,080	33,751
12	REV	Not Used	not_used	0	0	0	0	0	0	0
13	REV	Not Used	not_used	0	0	0	0	0	0	0
14	REV	TOTAL OTHER OPERATING REV		8,401	416,062	5,976,509	5,892,164	1,130,770	748,319	45,419
15	REV									
16	REV	**OTHER REVENUE SOURCES**								
17	REV	Not Used	not_used	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0
20	REV									
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0
22	REV									
23	REV	**TOTAL OPERATING REVENUES**		739,355	27,211,460	390,878,529	385,362,162	73,955,188	48,941,952	2,970,485

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	E	**OPERATION & MAINTENANCE EXPENSE**									
2	E	PRODUCTION EXPENSE									
3	E	E500-E557 Production Expenses									
4	E	Not Used	not_used	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0
7	E										
8	E	TRANSMISSION EXPENSES									
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0
11	E										
12	E	DISTRIBUTION EXPENSES									
13	E	Operation									
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	1,002,546	5,026	12,646	21	0	793	10,309
17	E	E583 OH Line Expenses	E365PLT	4,195,894	1,752,738	8,635	21,972	35	0	1,381	20,424
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	2,691,919	13,301	34,011	604	3	2,122	37,183
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	4,818	30	234	400	2	4	118,607
20	E	E586 Meter Expenses									
21	E	- Basic portion (minimum size)	METERPLT_07	5,865,310	4,892,223	15,762	26,334	4,157	65	1,790	0
22	E	- Excess portion	not_used	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07								
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	-1,119,615	-3,890	-6,498	-371	-6	-442	-2,764
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	17,799,821	76,809	180,525	9,832	129	11,434	397,495
27	E	E589 Rents	DISTPLT	1,330,133	519,792	3,191	24,096	40,969	174	399	48,890
28	E	Total Distribution Operation		53,572,940	26,424,628	114,975	286,822	55,278	362	17,040	627,381
29	E	Maintenance									
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	4,865,739	24,392	61,377	103	1	3,851	50,035
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	6,796,115	34,069	85,728	144	2	5,379	69,885
33	E	E593 Maint of Overhead Lines									
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	0	0	0	0	0	0	40,988
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	23,520,203	115,872	294,848	475	6	18,528	274,078
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	8,716,997	43,071	110,135	1,956	10	6,871	120,405
38	E	Not used	not_used	0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	2,207,903	934,630	6,383	13,325	40	0	812	19,347
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	1,997,626	997,003	3,210	10,960	0	0	713	0
41	E	E596 Maint of Street Lighting & Signal Systems									
42	E	- BPL luminaires	DIR_BPL_02	8,123,869	0	0	0	0	0	0	8,123,869
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	0	0	0	0	0	0	0
45	E	E597 Maint of Meters									
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	858,670	515,496	1,791	2,992	403	6	203	0
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	463,272	2,287	5,791	31	0	363	86,950
50	E	Total Distribution Maintenance		124,436,319	46,809,455	231,075	585,156	3,152	26	36,720	8,785,559

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	E	**OPERATION & MAINTENANCE EXPENSE**								
2	E	PRODUCTION EXPENSE								
3	E	E500-E557 Production Expenses								
4	E	Not Used	not_used	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0
7	E									
8	E	TRANSMISSION EXPENSES								
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0
11	E									
12	E	DISTRIBUTION EXPENSES								
13	E	Operation								
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	557	5,004	539,988	610,479	167,254	184,953	0
17	E	E583 OH Line Expenses	E365PLT	927	17,782	944,382	1,053,521	274,189	99,907	0
18	E	E584 Underground Line Expenses	E367PLT	1,433	16,855	1,450,438	1,620,787	255,120	76,133	0
19	E	E585 Street Lighting and System Expenses	E373PLT	3	42,594	2,659	2,911	523	321	
20	E	E586 Meter Expenses								
21	E	- Basic portion (minimum size)	METERPLT_07	0	0	788,936	69,459	18,133	32,280	16,172
22	E	- Excess portion	not_used	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07							
24	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
25	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-50	-13,196	-161,392	-5,335	-444	-109	-15
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	6,193	122,641	7,474,858	7,349,384	1,568,775	863,912	35,452
27	E	E589 Rents	DISTPLT	265	18,729	286,101	299,821	54,531	33,136	37
28	E	Total Distribution Operation		9,278	197,213	11,164,580	10,995,693	2,337,635	1,290,423	51,631
29	E	Maintenance								
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	2,705	24,288	2,620,770	2,962,886	811,745	897,649	0
32	E	E592 Maint of Station Equipment	E362PLT	3,778	33,924	3,660,503	4,138,346	1,133,787	1,253,772	0
33	E	E593 Maint of Overhead Lines								
34	E	- Direct assigned - BPL poles	DIR_BPL_02	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	0	118,210	0	0	0	0	0
36	E	- all other O&M	E365PLT	12,442	238,623	12,672,777	14,137,323	3,679,376	1,340,665	0
37	E	E594.0 Maint of Underground Lines	E367PLT	4,642	54,579	4,696,823	5,248,449	826,132	246,536	0
38	E	Not used	not_used	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	1,046	9,392	499,742	723,185	0	0	0
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	0	0	540,863	444,877	0	0	0
41	E	E596 Maint of Street Lighting & Signal Systems								
42	E	- BPL luminaires	DIR_BPL_02	0	0	0	0	0	0	0
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	0	3,594,664	0	0	0	0	0
45	E	E597 Maint of Meters								
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	0	0	269,199	41,633	19,584	6,653	709
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	3,645	40,720	249,504	276,853	64,680	37,437	7
50	E	Total Distribution Maintenance		368,309	4,114,401	25,210,180	27,973,551	6,535,305	3,782,713	716

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	E										
52	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
53	E										
54	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
55	E										
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	73,234,083	346,050	871,978	58,430	387	53,760	9,412,940
57	E										
58	E										
59	E	CUSTOMER ACCOUNTS EXPENSES									
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0
61	E	E902 Meter Reading									
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	9,323,486	7,339,625	25,498	42,601	486	8	579	0
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	9,323,486	3,872,092	29,343	50,748	1,084	16	22,608	0
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	-283,695	-223,330	-776	-1,296	-15	0	-18	0
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	-283,695	-117,820	-893	-1,544	-33	0	-688	0
70	E	E903 Customer Records and Collection									
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	275,332	234,579	815	1,362	78	1	93	579
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	275,332	113,267	858	1,484	32	0	661	1,689
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	266,527	209,815	729	1,218	14	0	17	0
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	266,527	110,690	839	1,451	31	0	646	0
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	40,496	29,269	102	170	2	0	2	123
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	40,496	16,660	126	218	5	0	97	248
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	3,872,512	3,225,657	11,206	18,722	1,019	16	1,215	920
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	3,872,512	1,593,082	12,072	20,879	446	7	9,302	23,761
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	531,469	388,574	1,242	2,651	32	0	179	2,656
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	531,469	218,637	1,657	2,865	61	1	1,277	3,261
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	33,170,904	23,974,248	83,289	139,151	1,588	25	1,892	100,598
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	33,170,904	13,645,918	103,410	178,846	3,822	58	79,675	203,532
85	E	Not used	not_used	0	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0	0
88	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
89	E										
90	E										
91	E	CUSTOMER SERVICE & INFO EXPENSES									
92	E	E907 & 908 - Cust Svs & Info									
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	2,356,739	1,963,075	6,820	11,394	620	10	739	560
95	E	- Utility work related	UTILWORK_04	847,228	619,436	1,980	4,226	51	0	286	4,234
96	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	41,297	29,847	104	173	2	0	2	125
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	E									
52	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
53	E									
54	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
55	E									
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		377,588	4,311,614	36,374,761	38,969,244	8,872,940	5,073,136	52,347
57	E									
58	E									
59	E	CUSTOMER ACCOUNTS EXPENSES								
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0
61	E	E902 Meter Reading								
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	0	0	1,798,602	104,913	8,739	2,147	289
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	0	0	2,025,741	1,749,632	452,811	759,497	359,912
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	0	0	-54,728	-3,192	-266	-65	-9
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	0	0	-61,639	-53,238	-13,778	-23,110	-10,951
70	E	E903 Customer Records and Collection								
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	11	2,765	33,814	1,118	93	23	3
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	91	820	59,257	51,180	13,246	22,217	10,528
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	0	0	51,416	2,999	250	61	8
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	0	0	57,909	50,016	12,944	21,711	10,289
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	2	586	7,172	2,773	231	57	8
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	13	121	8,716	7,528	1,948	3,268	1,549
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	17	4,393	483,506	113,727	9,473	2,327	313
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	1,284	11,534	833,444	719,846	186,299	312,477	148,078
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	49	7,206	119,052	8,790	794	223	19
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	176	1,583	114,383	98,793	25,568	42,885	20,322
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	1,830	480,357	5,874,979	2,271,049	189,166	46,478	6,254
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	11,002	98,800	7,139,061	6,166,005	1,595,784	2,676,598	1,268,393
85	E	Not used	not_used	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0	0
88	E	TOTAL CUSTOMER ACCTS EXPENSE		14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
89	E									
90	E									
91	E	CUSTOMER SERVICE & INFO EXPENSES								
92	E	E907 & 908 - Cust Svs & Info								
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	10	2,673	294,253	69,212	5,765	1,416	191
95	E	- Utility work related	UTILWORK_04	79	11,488	189,785	14,013	1,266	355	30
96	E	- Sales	SALES_06	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	2	598	7,314	2,827	236	58	8
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	E	- Utility work related	UTILWORK_04	1,163,089	850,371	2,718	5,801	71	1	392	5,813
102	E	- Acct Maint related	ACCTMAINT_06	689,620	574,428	1,996	3,334	182	3	216	164
103	E	- Not used	not_used	0	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	220,028	159,025	552	923	11	0	13	667
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
109	E										
110	E										
111	E										
112	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
113	E										
114	E	SALES EXPENSES									
115	E	E911-E916 Sales Expenses									
116	E	- Sales	SALES_06	0	0	0	0	0	0	0	0
117	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0
118	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0
119	E	- Utility work related	UTILWORK_04	40,922	29,919	96	204	2	0	14	205
120	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0	0
121	E	- Clause	not_used	0	0	0	0	0	0	0	0
122	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	29,919	96	204	2	0	14	205
123	E										
124	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	132,091,145	629,833	1,357,561	68,021	533	172,961	9,762,077
125	E										
126	E	ADMINISTRATIVE & GENERAL EXPENSE									
127	E	E920 A&G Salaries	REVREQ	5,694,688	2,500,067	13,364	72,516	104,468	448	2,146	202,020
128	E	E921 Office Supplies & Exp	REVREQ	622,444	273,264	1,461	7,926	11,419	49	235	22,081
129	E	E923 Outside Services Employed	DISTPLT	68,020,983	26,581,387	163,188	1,232,214	2,095,107	8,907	20,425	2,500,159
130	E	E924 Property Insurance	TOTPLT	1,802,573	709,496	4,338	32,318	54,733	233	567	65,411
131	E	E925 Injuries & Damages	LABOR	14,161,029	7,171,933	32,705	64,222	3,722	37	9,092	538,939
132	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-39,486,679	-180,064	-353,590	-20,494	-202	-50,058	-2,967,248
133	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	6,603,864	35,300	191,549	275,949	1,184	5,668	533,632
134	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	0	0	0	0	0	0
135	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	1,940,410	6,741	11,263	642	10	766	4,789
136	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	1,145,995	7,035	53,124	90,326	384	881	107,789
137	E	E931 Rents	DISTPLT	4,471,819	1,747,507	10,728	81,008	137,736	586	1,343	164,365
138	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0
139	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0
140	E	Not Used	not_used	0	0	0	0	0	0	0	0
141	E	TOTAL A&G EXPENSE		33,695,393	9,187,244	94,796	1,392,549	2,753,608	11,635	-8,937	1,171,937
142	E										
143	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	141,278,389	724,630	2,750,111	2,821,629	12,168	164,024	10,934,014

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	E	- Utility work related	UTILWORK_04	108	15,771	260,539	19,237	1,737	487	41
102	E	- Acct Maint related	ACCTMAINT_06	3	782	86,103	20,253	1,687	414	56
103	E	- Not used	not_used	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	12	3,186	38,970	15,064	1,255	308	41
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		214	34,498	876,964	140,606	11,945	3,040	367
109	E									
110	E									
111	E									
112	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
113	E									
114	E	SALES EXPENSES								
115	E	E911-E916 Sales Expenses								
116	E	- Sales	SALES_06	0	0	0	0	0	0	0
117	E	- Billing related	BILLING_06	0	0	0	0	0	0	0
118	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0
119	E	- Utility work related	UTILWORK_04	4	555	9,167	677	61	17	1
120	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0
121	E	- Clause	not_used	0	0	0	0	0	0	0
122	E	SALES EXPENSES TOTAL (ACCT 916)		4	555	9,167	677	61	17	1
123	E									
124	E	TOTAL OPER & MAINT EXCL A&G		392,282	4,954,833	55,751,578	50,402,464	11,368,248	8,942,987	1,867,720
125	E									
126	E	ADMINISTRATIVE & GENERAL EXPENSE								
127	E	E920 A&G Salaries	REVREQ	2,234	81,912	1,176,616	1,160,011	222,619	147,324	8,942
128	E	E921 Office Supplies & Exp	REVREQ	244	8,953	128,607	126,792	24,333	16,103	977
129	E	E923 Outside Services Employed	DISTPLT	13,574	957,750	14,630,793	15,332,416	2,788,625	1,694,535	1,905
130	E	E924 Property Insurance	TOTPLT	359	25,200	386,880	403,640	73,495	45,342	561
131	E	E925 Injuries & Damages	LABOR	2,094	232,843	2,505,054	2,647,907	465,037	383,357	104,089
132	E	E926 Employee Pension & Benefits	LABOR	-11,528	-1,281,967	-13,792,136	-14,578,643	-2,560,364	-2,110,657	-573,084
133	E	E928 Regulatory Comm Exp	REVREQ	5,902	216,367	3,108,002	3,064,140	588,042	389,153	23,619
134	E	E929 Duplicate Charges - credit	REVLPLS	0	0	0	-3,363,888	0	0	0
135	E	E930.1 General Advertising Expenses	CUSTAVG_04	87	22,870	279,709	9,245	770	189	25
136	E	E930.2 Misc General Expenses	DISTPLT	585	41,291	630,773	661,022	120,225	73,056	82
137	E	E931 Rents	DISTPLT	892	62,964	961,854	1,007,980	183,329	111,402	125
138	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0
139	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0
140	E	Not Used	not_used	0	0	0	0	0	0	0
141	E	TOTAL A&G EXPENSE		14,444	368,183	10,016,153	6,470,623	1,906,111	749,804	-432,758
142	E									
143	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		406,726	5,323,015	65,767,731	56,873,087	13,274,358	9,692,791	1,434,962

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**									
2	DE										
3	DE	E403 DEPRECIATION EXPENSE									
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	100,731,583	618,410	4,669,539	7,939,520	33,752	77,400	9,474,485
7	DE	General Plant	GENPLT	19,786,964	7,586,813	47,688	368,609	630,527	2,677	5,985	752,817
8	DE	Common Plant	COMPLT	9,215,747	4,928,718	25,149	78,726	79,070	343	8,818	117,267
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
11	DE										
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT									
13	DE	not used	not_used	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	2,328,490	14,636	113,131	193,517	822	1,837	231,049
15	DE	Meter Reading	MRCOST_07	492,670	387,839	1,347	2,251	26	0	31	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	8,746,911	42,181	72,170	1,426	22	17,722	51,882
17	DE	not used	not_used	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
20	DE										
21	DE	E407 AMORT OF PROPERTY LOSSES									
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0
26	DE										
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	11,463,240	58,165	187,552	194,968	844	19,589	282,931
28	DE										
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	124,710,354	749,412	5,304,425	8,844,086	37,616	111,794	10,627,501

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**								
2	DE									
3	DE	E403 DEPRECIATION EXPENSE								
4	DE	Production Plant	not_used	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	51,439	3,629,444	55,444,171	58,103,010	10,567,643	6,421,529	7,217
7	DE	General Plant	GENPLT	4,087	288,386	4,187,658	4,583,028	823,833	504,855	0
8	DE	Common Plant	COMPLT	1,504	79,403	1,832,852	1,344,477	271,498	324,944	122,979
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
11	DE									
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT								
13	DE	not used	not_used	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	1,254	88,509	1,285,245	1,406,590	252,845	154,946	0
15	DE	Meter Reading	MRCOST_07	0	0	95,041	5,544	462	113	15
16	DE	Customer Service related	CUSTSVSX	2,184	95,557	2,879,744	1,699,886	371,014	575,399	269,925
17	DE	not used	not_used	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
20	DE									
21	DE	E407 AMORT OF PROPERTY LOSSES								
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0
26	DE									
27	DE	TOTAL AMORTIZATION EXPENSE		3,439	184,066	4,260,031	3,112,020	624,321	730,459	269,940
28	DE									
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		60,469	4,181,299	65,724,711	67,142,535	12,287,294	7,981,787	400,136

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	EO	**OTHER OPERATING EXPENSES**									
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**									
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-108,431	-663	-4,939	-8,365	-36	-87	-9,997
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-5,710,658	-26,041	-51,137	-2,964	-29	-7,239	-429,130
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-5,819,089	-26,704	-56,076	-11,329	-65	-7,326	-439,127
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**									
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	21,861,618	19,145,965	61,686	103,059	16,270	254	7,006	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	4,303,381	1,700,510	9,904	63,619	98,859	420	1,340	160,975
14	EO	BGS Administrative Expense Adjustment	A_GEXP	-220,495	-96,115	-543	-3,448	-5,478	-23	-81	-8,174
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-1,199,974	-607,733	-2,771	-5,442	-315	-3	-770	-45,668
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	7,361,661	3,728,355	17,002	33,386	1,935	19	4,726	280,169
22	EO	Payroll Taxes (Rate Year)	LABOR	506,132	256,333	1,169	2,295	133	1	325	19,262
23	EO	Interest Syncronization	TOTPLTNET	-1,029,929	-406,983	-2,370	-15,226	-23,660	-101	-321	-38,526
24	EO	- add'l tax effects on rev req	TOTPLTNET	-402,717	-159,136	-927	-5,954	-9,251	-39	-125	-15,064
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	20,935,341	10,602,821	48,350	94,945	5,503	54	13,441	796,755
26	EO	COLI Interest Expense Recovery	LABOR	2,119,856	1,073,613	4,896	9,614	557	5	1,361	80,677
27	EO	- add'l tax effects on rev req	LABOR	828,893	419,798	1,914	3,759	218	2	532	31,546
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-41,607	-16,376	-100	-746	-1,263	-5	-13	-1,510
32	EO	- add'l tax effects on rev req	TOTPLT	-16,269	-6,403	-39	-292	-494	-2	-5	-590
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	616,778	242,765	1,484	11,058	18,728	80	194	22,381
36	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-6,799,891	-41,575	-309,738	-524,564	-2,230	-5,431	-626,907
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	482,666	189,978	1,162	8,654	14,655	62	152	17,515
38	EO	Rate Case Expenses	TOTPLT	188,766	74,298	454	3,384	5,732	24	59	6,850
39	EO	Depreciation Rate Change	DEPREXP	44,543,977	17,590,557	107,371	794,799	1,343,458	5,712	14,322	1,606,811
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT								
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		83,562,007	46,921,390	207,023	787,649	948,159	4,341	36,705	2,285,828
47	EO										
48	EO	**TOTAL OTHER OPERATING EXPENSES**		72,010,790	41,102,301	180,319	731,573	936,830	4,276	29,379	1,846,701
49	EO	TOTAL OPERATING REVENUES	CALCULATED	1,887,985,784	827,236,523	4,421,864	23,994,492	34,566,954	148,276	712,878	66,845,666
50	EO	LESS:									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	EO	**OTHER OPERATING EXPENSES**								
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**								
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-55	-3,851	-59,126	-61,688	-11,232	-6,930	-86
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-1,667	-185,401	-1,994,652	-2,108,398	-370,286	-305,248	-82,881
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-1,722	-189,253	-2,053,778	-2,170,086	-381,518	-312,178	-82,967
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**								
12	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	0	0	2,527,379	0	0	0	0
13	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	873	61,865	926,252	981,805	181,145	115,064	750
14	EO	BGS Administrative Expense Adjustment	A_GEXP	-51	-3,258	-47,013	-41,565	-8,820	-5,648	-277
15	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
16	EO	Deferred Compensation & Severance Expense	LABOR	-177	-19,731	-212,273	-224,378	-39,406	-32,485	-8,820
17	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0
18	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0
19	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0
20	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0
21	EO	Wage Increases (Rate Year)	LABOR	1,088	121,044	1,302,261	1,376,524	241,751	199,289	54,111
22	EO	Payroll Taxes (Rate Year)	LABOR	75	8,322	89,534	94,639	16,621	13,702	3,720
23	EO	Interest Syncronization	TOTPLTNET	-209	-14,806	-221,680	-234,976	-43,353	-27,538	-179
24	EO	- add'l tax effects on rev req	TOTPLTNET	-82	-5,789	-86,680	-91,879	-16,952	-10,768	-70
25	EO	Pension & Fringe Benefit (Rate Year)	LABOR	3,096	344,229	3,703,415	3,914,605	687,500	566,746	153,882
26	EO	COLI Interest Expense Recovery	LABOR	313	34,856	374,998	396,382	69,614	57,387	15,582
27	EO	- add'l tax effects on rev req	LABOR	123	13,629	146,629	154,991	27,220	22,439	6,093
28	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0
29	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0
30	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0
31	EO	Gains / Losses Normalization	TOTPLT	-8	-582	-8,930	-9,317	-1,696	-1,047	-13
32	EO	- add'l tax effects on rev req	TOTPLT	-3	-227	-3,492	-3,643	-663	-409	-5
33	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0
34	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0
35	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	123	8,623	132,377	138,112	25,148	15,514	192
36	EO	Test Year Amortization Adjustments	TOTPLT	-3,438	-241,524	-3,707,904	-3,868,534	-704,388	-434,564	-5,381
37	EO	Insurance Premium Increases (Rate Year)	TOTPLT	96	6,748	103,593	108,081	19,679	12,141	150
38	EO	Rate Case Expenses	TOTPLT	38	2,639	40,514	42,269	7,696	4,748	59
39	EO	Depreciation Rate Change	DEPREXP	8,858	620,886	9,547,245	9,945,794	1,811,598	1,126,341	20,223
40	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0
41	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0
42	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0
43	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0
44	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0
45	EO	Test Year Corrections	TOTPLT							
46	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		10,712	936,640	14,603,278	12,676,955	2,272,343	1,620,651	250,332
47	EO									
48	EO	**TOTAL OTHER OPERATING EXPENSES**		8,990	747,388	12,549,500	10,506,869	1,890,825	1,308,473	167,365
49	EO	TOTAL OPERATING REVENUES	CALCULATED	739,355	27,211,460	390,878,529	385,362,162	73,955,188	48,941,952	2,970,485
50	EO	LESS:								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	311,457,637	141,278,389	724,630	2,750,111	2,821,629	12,168	164,024	10,934,014
52	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	308,163,419	124,710,354	749,412	5,304,425	8,844,086	37,616	111,794	10,627,501
53	EO	OTHER OPERATING EXPENSES	CALCULATED	72,010,790	41,102,301	180,319	731,573	936,830	4,276	29,379	1,846,701
54	EO	NET OPERATING INCOME BEFORE TAXES		1,196,353,939	520,145,478	2,767,503	15,208,382	21,964,410	94,216	407,681	43,437,450
55	EO	LESS:									
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(54,367,739)	(316,659)	(2,033,976)	(3,160,676)	(13,442)	(42,844)	(5,146,593)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,333,939,214	574,513,217	3,084,162	17,242,359	25,125,086	107,658	450,525	48,584,043
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	406,726	5,323,015	65,767,731	56,873,087	13,274,358	9,692,791	1,434,962
52	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	60,469	4,181,299	65,724,711	67,142,535	12,287,294	7,981,787	400,136
53	EO	OTHER OPERATING EXPENSES	CALCULATED	8,990	747,388	12,549,500	10,506,869	1,890,825	1,308,473	167,365
54	EO	NET OPERATING INCOME BEFORE TAXES		263,170	16,959,758	246,836,587	250,839,671	46,502,711	29,958,900	968,022
55	EO	LESS:								
56	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(27,905)	(1,977,913)	(29,613,608)	(31,389,727)	(5,791,467)	(3,678,756)	(23,968)
57	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		291,076	18,937,671	276,450,195	282,229,398	52,294,178	33,637,656	991,990
58	EO	Adjustment Reclassification Minus	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0
59	EO	Adjustment Reclassification Plus	ADJ_Plus_04	0	0	0	0	0	0	10,316

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**									
2	TI										
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**									
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-108,083	-42,542	-260	-1,938	-3,282	-14	-34	-3,922
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	16,349	6,435	39	293	496	2	5	593
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	4,633	28	211	357	2	4	427
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-20,866,765	-8,213,195	-50,216	-374,115	-633,590	-2,694	-6,560	-757,205
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-1,855,840	-730,462	-4,466	-33,273	-56,350	-240	-583	-67,344
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-1,117,127	-565,775	-2,580	-5,066	-294	-3	-717	-42,515
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-58,279	-29,516	-135	-264	-15	0	-37	-2,218
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-11,513,122	-4,546,568	-27,752	-205,429	-347,239	-1,476	-3,702	-415,307
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	4,645,423	1,835,670	10,692	68,675	106,717	454	1,447	173,769
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	6,684,538	2,641,440	15,385	98,820	153,560	653	2,082	250,046
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-5,352	-2,710	-12	-24	-1	0	-3	-204
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-7,086,760	-3,589,129	-16,367	-32,139	-1,863	-18	-4,550	-269,707
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	82	32	0	1	2	0	0	3
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	38,419	19,458	89	174	10	0	25	1,462
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	1,298,774	511,200	3,126	23,285	39,435	168	408	47,129
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-33,454,683	-13,211,361	-80,641	-596,932	-1,009,002	-4,290	-10,757	-1,206,793
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	162,269	82,182	375	736	43	0	104	6,176
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-5,622	-2,213	-14	-101	-171	-1	-2	-204
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-236,259	-92,992	-569	-4,236	-7,174	-30	-74	-8,573
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	319,172	125,627	768	5,722	9,691	41	100	11,582
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	42,165	16,596	101	756	1,280	5	13	1,530
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	154,681	78,339	357	702	41	0	99	5,887
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	17,908,279	7,072,036	43,167	319,538	540,119	2,296	5,758	645,996
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-181,414	-1,109	-8,263	-13,995	-59	-145	-16,725
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	125,367	49,345	302	2,248	3,807	16	39	4,549
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-328,125	-129,661	-755	-4,851	-7,538	-32	-102	-12,274
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-42,165	-16,596	-101	-756	-1,280	-5	-13	-1,530

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	TI	**[TI] DEVELOPMENT OF INCOME TAXES**								
2	TI									
3	TI	**[TI] TAX ADJUSTMENTS - FEDERAL**								
4	TI	[TI][Fed Tax Adj.] Additional Expenses on Rental Property	TOTPLT	-22	-1,511	-23,198	-24,203	-4,407	-2,719	-34
5	TI	[TI][Fed Tax Adj.] Additional Rental Income - NJ Properties	TOTPLT	3	229	3,509	3,661	667	411	5
6	TI	[TI][Fed Tax Adj.] Amort of Def Gain on Sale of Services Asse	not_used	0	0	0	0	0	0	0
7	TI	[TI][Fed Tax Adj.] Amort of Deferred Gain on Sale of Generati	not_used	0	0	0	0	0	0	0
8	TI	[TI][Fed Tax Adj.] Amortization of Reacquisition of Pref Stock	TOTPLT	2	165	2,526	2,636	480	296	4
9	TI	[TI][Fed Tax Adj.] CECL Reserve	not_used	0	0	0	0	0	0	0
10	TI	[TI][Fed Tax Adj.] CEF- EC AMI	TOTPLT	-4,153	-291,723	-4,478,562	-4,672,579	-850,789	-524,885	-6,499
11	TI	[TI][Fed Tax Adj.] CEF- EV Deferral	TOTPLT	-369	-25,945	-398,313	-415,568	-75,667	-46,682	-578
12	TI	[TI][Fed Tax Adj.] Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
13	TI	[TI][Fed Tax Adj.] Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
14	TI	[TI][Fed Tax Adj.] Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
15	TI	[TI][Fed Tax Adj.] Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
16	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Book	LABOR	-165	-18,368	-197,617	-208,887	-36,686	-30,242	-8,211
17	TI	[TI][Fed Tax Adj.] Company Owned Life Insurance - Tax	LABOR	-9	-958	-10,309	-10,897	-1,914	-1,578	-428
18	TI	[TI][Fed Tax Adj.] COVID Deferrals	not_used	0	0	0	0	0	0	0
19	TI	[TI][Fed Tax Adj.] Current SHARE -- FT	DEPREXP	-2,290	-160,478	-2,467,642	-2,570,654	-468,237	-291,121	-5,227
20	TI	[TI][Fed Tax Adj.] Customer Advances	TOTPLTNET	942	66,782	999,873	1,059,841	195,543	124,209	809
21	TI	[TI][Fed Tax Adj.] Customer Connection Fees (Contributions i	TOTPLTNET	1,356	96,096	1,438,768	1,525,060	281,377	178,731	1,164
22	TI	[TI][Fed Tax Adj.] Deduction for Retention Payments (c)	LABOR	-1	-88	-947	-1,001	-176	-145	-39
23	TI	[TI][Fed Tax Adj.] Deferred Employer ER FICA	LABOR	-1,048	-116,524	-1,253,632	-1,325,121	-232,723	-191,848	-52,090
24	TI	[TI][Fed Tax Adj.] Diesel Fuel Tax Credit	TOTPLT	0	1	18	18	3	2	0
25	TI	[TI][Fed Tax Adj.] Entertainment (100%)	LABOR	6	632	6,796	7,184	1,262	1,040	282
26	TI	[TI][Fed Tax Adj.] FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
27	TI	[TI][Fed Tax Adj.] Fed Amort of Deferred Gain on Sale of Gen	not_used	0	0	0	0	0	0	0
28	TI	[TI][Fed Tax Adj.] Injuries & Damages - FT	TOTPLT	258	18,157	278,751	290,827	52,954	32,670	405
29	TI	[TI][Fed Tax Adj.] Line Pack Adjustment	not_used	0	0	0	0	0	0	0
30	TI	[TI][Fed Tax Adj.] Plant Related	DEPREXP	-6,653	-466,316	-7,170,444	-7,469,773	-1,360,597	-845,937	-15,189
31	TI	[TI][Fed Tax Adj.] Previously Deducted Amort - Reacquired Bo	not_used	0	0	0	0	0	0	0
32	TI	[TI][Fed Tax Adj.] Qualified Transportation Fringe	LABOR	24	2,668	28,705	30,342	5,329	4,393	1,193
33	TI	[TI][Fed Tax Adj.] R & D Credits CF	not_used	0	0	0	0	0	0	0
34	TI	[TI][Fed Tax Adj.] R&D Expenditure	TOTPLT	-1	-79	-1,207	-1,259	-229	-141	-2
35	TI	[TI][Fed Tax Adj.] Rabbi Trust	not_used	0	0	0	0	0	0	0
36	TI	[TI][Fed Tax Adj.] RE - Lease Liability	TOTPLT	-47	-3,303	-50,708	-52,904	-9,633	-5,943	-74
37	TI	[TI][Fed Tax Adj.] RE - ROU Lease Asset	TOTPLT	64	4,462	68,503	71,470	13,013	8,028	99
38	TI	[TI][Fed Tax Adj.] Reversal of Book Income from Partnerships	TOTPLT	8	589	9,050	9,442	1,719	1,061	13
39	TI	[TI][Fed Tax Adj.] Severance Pay (nc)	LABOR	23	2,543	27,363	28,923	5,080	4,187	1,137
40	TI	[TI][Fed Tax Adj.] State NOL CF (c)	DEPREXP	3,561	249,619	3,838,336	3,998,567	728,327	452,830	8,130
41	TI	[TI][Fed Tax Adj.] Tax Net Bad Debt Writeoffs - FT	TOTPLT	-92	-6,444	-98,923	-103,208	-18,792	-11,594	-144
42	TI	[TI][Fed Tax Adj.] Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0
43	TI	[TI][Fed Tax Adj.] Unrealized G/L on Equity Securities	TOTPLT	25	1,753	26,907	28,073	5,112	3,154	39
44	TI	[TI][Fed Tax Adj.] Stock-Based Compensation - Reverse Book	TOTPLTNET	-67	-4,717	-70,625	-74,861	-13,812	-8,773	-57
45	TI	[TI][Fed Tax Adj.] GainState LILOAudit Refunds not yet receiv	TOTPLTNET	0	0	0	0	0	0	0
46	TI	[TI][Fed Tax Adj.] Repair Allowance	TOTPLT	0	0	0	0	0	0	0
47	TI	[TI][Fed Tax Adj.] Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0
48	TI	[TI][Fed Tax Adj.] Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0
49	TI	[TI][Fed Tax Adj.] Diesel Fuel Credit	not_used	0	0	0	0	0	0	0
50	TI	[TI][Fed Tax Adj.] Partnership Income/Loss (nc)	TOTPLT	-8	-589	-9,050	-9,442	-1,719	-1,061	-13

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-417,376	-211,383	-964	-1,893	-110	-1	-268	-15,884
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-407,940	-2,376	-15,262	-23,716	-101	-321	-38,617
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	1,841,683	932,731	4,253	8,352	484	5	1,182	70,091
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-1,076,666	-423,778	-2,591	-19,303	-32,691	-139	-338	-39,070
63	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	3,363,340	1,323,816	8,094	60,300	102,123	434	1,057	122,047
64	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
65	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	11,058	5,600	26	50	3	0	7	421
69	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
70	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-344,695	-174,573	-796	-1,563	-91	-1	-221	-13,118
71	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	87,346	34,379	210	1,566	2,652	11	27	3,170
72	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipmer	TOTPLT	0	0	0	0	0	0	0	0
73	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stock	LABOR	0	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	905,779	357,925	2,085	13,390	20,808	88	282	33,882
78	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
79	TI	[TI][Fed Tax Adj.] Pension	LABOR	-3,671,962	-1,859,686	-8,480	-16,653	-965	-9	-2,358	-139,747
80	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-105,080,197	-53,218,455	-242,682	-476,553	-27,621	-272	-67,466	-3,999,130
81	TI	[TI][Fed Tax Adj.] Deferred Return on CIP II	TOTPLT	66,348	26,115	160	1,190	2,015	9	21	2,408
82	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP II	TOTPLT	52,458	20,648	126	941	1,593	7	16	1,904
83	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
84	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	91,151	36,019	210	1,348	2,094	9	28	3,410
85	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0
86	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	1,120,547	442,792	2,579	16,565	25,742	109	349	41,916
87	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-1,045,327	-413,068	-2,406	-15,453	-24,014	-102	-326	-39,102
88	TI										
89	TI										
90	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
91	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-82,615	-32,646	-190	-1,221	-1,898	-8	-26	-3,090
94	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0
95	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	401,853	158,795	925	5,941	9,232	39	125	15,032
96	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	107,143	42,172	258	1,921	3,253	14	34	3,888
97	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0
98	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	62,834	24,829	145	929	1,443	6	20	2,350
99	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	1,046,714	413,616	2,409	15,474	24,046	102	326	39,154
100	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	TI	[TI][Fed Tax Adj.] Meals and Entertainment (50%)	LABOR	-62	-6,863	-73,833	-78,043	-13,706	-11,299	-3,068
52	TI	[TI][Fed Tax Adj.] Company owned life insurance	LABOR	0	0	0	0	0	0	0
53	TI	[TI][Fed Tax Adj.] ESOP/401(k) Cash Dividends	TOTPLTNET	-209	-14,841	-222,201	-235,528	-43,455	-27,603	-180
54	TI	[TI][Fed Tax Adj.] Medicare Subsidy	LABOR	0	0	0	0	0	0	0
55	TI	[TI][Fed Tax Adj.] Dividends Received Deduction-2	TOTPLTNET	0	0	0	0	0	0	0
56	TI	[TI][Fed Tax Adj.] W-2 Earnings Exceeding $1.000.000	LABOR	272	30,282	325,790	344,368	60,479	49,857	13,537
57	TI	[TI][Fed Tax Adj.] Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0
58	TI	[TI][Fed Tax Adj.] Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
59	TI	[TI][Fed Tax Adj.] Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0
60	TI	[TI][Fed Tax Adj.] Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
61	TI	[TI][Fed Tax Adj.] Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
62	TI	[TI][Fed Tax Adj.] AFUDC / IDC - Debt	TOTPLT	-214	-15,052	-231,081	-241,092	-43,898	-27,083	-335
63	TI	[TI][Fed Tax Adj.] Capitalized Interest - Section 263A	TOTPLT	669	47,020	721,862	753,134	137,132	84,602	1,048
64	TI	[TI][Fed Tax Adj.] Cost of removal	TOTPLT	0	0	0	0	0	0	0
65	TI	[TI][Fed Tax Adj.] Utility Commodity Costs	not_used	0	0	0	0	0	0	0
66	TI	[TI][Fed Tax Adj.] RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
67	TI	[TI][Fed Tax Adj.] SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
68	TI	[TI][Fed Tax Adj.] Def Comp - Off/Dir/NOC (c)	LABOR	2	182	1,956	2,068	363	299	81
69	TI	[TI][Fed Tax Adj.] Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
70	TI	[TI][Fed Tax Adj.] Additional Vacation Pay Adj (c)	LABOR	-51	-5,668	-60,976	-64,453	-11,319	-9,331	-2,534
71	TI	[TI][Fed Tax Adj.] Third Party Claims	TOTPLT	17	1,221	18,747	19,559	3,561	2,197	27
72	TI	[TI][Fed Tax Adj.] Deduction for New Network Meter Equipmer	TOTPLT	0	0	0	0	0	0	0
73	TI	[TI][Fed Tax Adj.] Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
74	TI	[TI][Fed Tax Adj.] Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
75	TI	[TI][Fed Tax Adj.] Defer Dividend Equivalents/Restricted Stock	LABOR	0	0	0	0	0	0	0
76	TI	[TI][Fed Tax Adj.] Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
77	TI	[TI][Fed Tax Adj.] CIAC Tax Gross Up	TOTPLTNET	184	13,021	194,958	206,651	38,128	24,219	158
78	TI	[TI][Fed Tax Adj.] FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
79	TI	[TI][Fed Tax Adj.] Pension	LABOR	-543	-60,376	-649,562	-686,604	-120,584	-99,405	-26,990
80	TI	[TI][Fed Tax Adj.] OPEB	LABOR	-15,537	-1,727,781	-18,588,450	-19,648,470	-3,450,749	-2,844,653	-772,378
81	TI	[TI][Fed Tax Adj.] Deferred Return on CIP II	TOTPLT	13	928	14,240	14,857	2,705	1,669	21
82	TI	[TI][Fed Tax Adj.] Deferred Depreciation on CIP II	TOTPLT	10	733	11,259	11,747	2,139	1,320	16
83	TI	[TI][Fed Tax Adj.] FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
84	TI	[TI][Fed Tax Adj.] Assessment by Board of Public Utilities of th	TOTPLTNET	18	1,310	19,619	20,796	3,837	2,437	16
85	TI	[TI][Fed Tax Adj.] Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0
86	TI	[TI][Fed Tax Adj.] Casualty Loss Deferred O&M	TOTPLTNET	227	16,109	241,184	255,650	47,168	29,961	195
87	TI	[TI][Fed Tax Adj.] Performance Incentive Plan Adj (c)	TOTPLTNET	-212	-15,028	-224,994	-238,489	-44,002	-27,950	-182
88	TI									
89	TI									
90	TI	[TI][Fed Tax Adj.] LCAPP	TOTPLTNET	0	0	0	0	0	0	0
91	TI	[TI][Fed Tax Adj.] Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
92	TI	[TI][Fed Tax Adj.] Penalties	not_used	0	0	0	0	0	0	0
93	TI	[TI][Fed Tax Adj.] Restricted Stock - Permanent	TOTPLTNET	-17	-1,188	-17,782	-18,849	-3,478	-2,209	-14
94	TI	[TI][Fed Tax Adj.] Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0
95	TI	[TI][Fed Tax Adj.] Legal Reserves (nc)	TOTPLTNET	82	5,777	86,494	91,682	16,915	10,745	70
96	TI	[TI][Fed Tax Adj.] Material & Supplies Reserve (c)	TOTPLT	21	1,498	22,996	23,992	4,369	2,695	33
97	TI	[TI][Fed Tax Adj.] Lobbying Expenses	LABOR	0	0	0	0	0	0	0
98	TI	[TI][Fed Tax Adj.] Bankruptcies and Accum Provision for Rent	TOTPLTNET	13	903	13,524	14,335	2,645	1,680	11
99	TI	[TI][Fed Tax Adj.] Real Estate Taxes (nc)	TOTPLTNET	212	15,047	225,293	238,805	44,060	27,987	182
100	TI	[TI][Fed Tax Adj.] Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT								
102	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-71,833,233	-349,555	-1,166,162	-1,141,853	-5,024	-85,044	-5,603,458
103	TI										
104	TI	**[TI] TAX ADJUSTMENTS - STATE**									
105	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0	0
106	TI	[TI] Federal Depreciation Reversal	DEPREXP	72,042,765	28,449,916	173,655	1,285,460	2,172,829	9,238	23,164	2,598,761
107	TI	[TI] State Tax Depreciation	DEPREXP	36,681,624	14,485,690	88,419	654,511	1,106,328	4,704	11,794	1,323,197
108	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0	0
109	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	42,935,606	262,074	1,939,971	3,279,157	13,941	34,958	3,921,958
110	TI										
111	TI	**[TI] TAXABLE NET INCOME - STATE**		1,293,338,867	545,615,590	2,996,682	18,016,168	27,262,390	116,575	400,439	46,902,543
112	TI	[TI] State Tax Liability		116,400,498	49,105,403	269,701	1,621,455	2,453,615	10,492	36,040	4,221,229
113	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0
114	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		116,400,498	49,105,403	269,701	1,621,455	2,453,615	10,492	36,040	4,221,229
115	TI										
116	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		1,068,213,981	453,574,581	2,464,907	14,454,742	21,529,618	92,142	329,442	38,759,356
117	TI	[TI] Federal Tax Liability		224,324,936	95,250,662	517,630	3,035,496	4,521,220	19,350	69,183	8,139,465
118	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0	0
119	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0	0
120	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		224,324,936	95,250,662	517,630	3,035,496	4,521,220	19,350	69,183	8,139,465
121	TI										
122	TI	**[TI] TOTAL INCOME TAX EXPENSE**		340,725,434	144,356,065	787,332	4,656,951	6,974,835	29,842	105,222	12,360,694
123	TI										
124	TI										
125	TI										
126	TI										
127	TI	**[TI] TAX RATES**									
128	TI	[TI] FEDERAL TAX RATE - CURRENT		21.000%							
129	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE		9.000%							
130	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0							
131	TI	[TI] EFFECTIVE TAX RATE		28.110%							
132	TI	[TI] COMPOSITE RATE		28.110%							
133	TI	[TI] 1 - EFFECTIVE TAX RATE		71.89000%							
134	TI										
135	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**									
136	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-16,349	-6,435	-39	-293	-496	-2	-5	-593
137	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0
138	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	53,745	21,154	129	964	1,632	7	17	1,950
140	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-442,792	-2,579	-16,565	-25,742	-109	-349	-41,916
141	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0	0
142	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	20,866,765	8,213,195	50,216	374,115	633,590	2,694	6,560	757,205
143	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	1,855,840	730,462	4,466	33,273	56,350	240	583	67,344
144	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0
145	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	2,912,070	1,149,986	7,019	51,960	87,829	373	936	105,046
150	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-4,645,423	-1,835,670	-10,692	-68,675	-106,717	-454	-1,447	-173,769

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	TI	**[TI][Fed Tax Adj.] Miscellaneous**	TOTPLT							
102	TI	**[TI] TOTAL TAX ADJUSTMENTS - FEDERAL**		-23,754	-2,366,110	-27,673,028	-29,098,195	-5,152,208	-3,961,522	-865,589
103	TI									
104	TI	**[TI] TAX ADJUSTMENTS - STATE**								
105	TI	[TI] TEFA	TEFA_04	0	0	0	0	0	0	0
106	TI	[TI] Federal Depreciation Reversal	DEPREXP	14,327	1,004,184	15,441,144	16,085,732	2,929,970	1,821,677	32,708
107	TI	[TI] State Tax Depreciation	DEPREXP	7,295	511,295	7,862,084	8,190,285	1,491,837	927,533	16,654
108	TI	[Electric] Not Used_42	not_used	0	0	0	0	0	0	0
109	TI	**[TI] TOTAL TAX ADJUSTMENTS - STATE**		21,622	1,515,479	23,303,228	24,276,018	4,421,806	2,749,211	49,361
110	TI									
111	TI	**[TI] TAXABLE NET INCOME - STATE**		288,943	18,087,039	272,080,394	277,407,220	51,563,776	32,425,345	175,762
112	TI	[TI] State Tax Liability		26,005	1,627,834	24,487,235	24,966,650	4,640,740	2,918,281	15,819
113	TI	[TI] Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0
114	TI	**[TI] TOTAL STATE INCOME TAX LIABILITY**		26,005	1,627,834	24,487,235	24,966,650	4,640,740	2,918,281	15,819
115	TI									
116	TI	**[TI] TAXABLE NET INCOME - FEDERAL**		241,317	14,943,727	224,289,931	228,164,553	42,501,230	26,757,854	110,582
117	TI	[TI] Federal Tax Liability		50,676	3,138,183	47,100,886	47,914,556	8,925,258	5,619,149	23,222
118	TI	[Electric] Not Used_43	not_used	0	0	0	0	0	0	0
119	TI	[Electric] Not Used_44	not_used	0	0	0	0	0	0	0
120	TI	**[TI] TOTAL FEDERAL INCOME TAX LIABILITY**		50,676	3,138,183	47,100,886	47,914,556	8,925,258	5,619,149	23,222
121	TI									
122	TI	**[TI] TOTAL INCOME TAX EXPENSE**		76,681	4,766,016	71,588,121	72,881,206	13,565,998	8,537,430	39,041
123	TI									
124	TI									
125	TI									
126	TI									
127	TI	**[TI] TAX RATES**								
128	TI	[TI] FEDERAL TAX RATE - CURRENT								
129	TI	[TI] NEW JERSEY CORP BUSINESS TAX RATE								
130	TI	[TI] CUSTOMER ACCT UNCOLLECTIBLE RATE								
131	TI	[TI] EFFECTIVE TAX RATE								
132	TI	[TI] COMPOSITE RATE								
133	TI	[TI] 1 - EFFECTIVE TAX RATE								
134	TI									
135	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJUSTED**								
136	TI	[TI] 410 + 411 - Additional Rental Income - NJ Properties	TOTPLT	-3	-229	-3,509	-3,661	-667	-411	-5
137	TI	[TI] 410 + 411 - Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0
138	TI	[TI] 410 + 411 - Amort of Deferred Gain on Sale of Generation	not_used	0	0	0	0	0	0	0
139	TI	[TI] 410 + 411 - Bankruptcies and Accum Provision for Rent R	TOTPLT	11	751	11,535	12,035	2,191	1,352	17
140	TI	[TI] 410 + 411 - Casualty Loss Deferred O&M	TOTPLTNET	-227	-16,109	-241,184	-255,650	-47,168	-29,961	-195
141	TI	[TI] 410 + 411 - CECL Reserve	not_used	0	0	0	0	0	0	0
142	TI	[TI] 410 + 411 - CEF- EC AMI	TOTPLT	4,153	291,723	4,478,562	4,672,579	850,789	524,885	6,499
143	TI	[TI] 410 + 411 - CEF- EV Deferral	TOTPLT	369	25,945	398,313	415,568	75,667	46,682	578
144	TI	[TI] 410 + 411 - Clause - Demographic Studies	not_used	0	0	0	0	0	0	0
145	TI	[TI] 410 + 411 - Clause - Navigant Studies	not_used	0	0	0	0	0	0	0
146	TI	[TI] 410 + 411 - Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0
147	TI	[TI] 410 + 411 - Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0
148	TI	[TI] 410 + 411 - COVID Deferrals	not_used	0	0	0	0	0	0	0
149	TI	[TI] 410 + 411 - Current SHARE -- FT	DEPREXP	579	40,591	624,153	650,208	118,434	73,635	1,322
150	TI	[TI] 410 + 411 - Customer Advances	TOTPLTNET	-942	-66,782	-999,873	-1,059,841	-195,543	-124,209	-809

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	5,352	2,710	12	24	1	0	3	204
152	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	7,086,760	3,589,129	16,367	32,139	1,863	18	4,550	269,707
153	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0
154	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-328,505	-129,300	-791	-5,890	-9,975	-42	-103	-11,921
156	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0
157	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	42,165	16,596	101	756	1,280	5	13	1,530
159	TI	[TI] 410 + 411 - Plant Related	DEPREXP	37,305,084	14,731,896	89,922	665,635	1,125,131	4,784	11,995	1,345,687
160	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0	0
161	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-15,263	-6,007	-37	-274	-463	-2	-5	-554
162	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	236,259	92,992	569	4,236	7,174	30	74	8,573
163	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-319,172	-125,627	-768	-5,722	-9,691	-41	-100	-11,582
164	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-1,046,714	-411,988	-2,519	-18,766	-31,782	-135	-329	-37,983
165	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-42,165	-16,596	-101	-756	-1,280	-5	-13	-1,530
166	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-154,681	-78,339	-357	-702	-41	0	-99	-5,887
167	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-17,908,279	-7,072,036	-43,167	-319,538	-540,119	-2,296	-5,758	-645,996
168	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-125,367	-49,345	-302	-2,248	-3,807	-16	-39	-4,549
169	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T**									
170	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0
171	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0
172	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0
173	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0
175	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	1,076,666	423,778	2,591	19,303	32,691	139	338	39,070
177	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-3,363,340	-1,323,816	-8,094	-60,300	-102,123	-434	-1,057	-122,047
178	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0	0
179	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0
182	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-11,058	-5,600	-26	-50	-3	0	-7	-421
183	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0
184	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	344,695	174,573	796	1,563	91	1	221	13,118
185	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-87,346	-34,379	-210	-1,566	-2,652	-11	-27	-3,170
186	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0
187	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0	0
188	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0	0
191	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0
192	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-905,779	-357,925	-2,085	-13,390	-20,808	-88	-282	-33,882
193	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0
194	TI	[TI] 410 + 411 - Pension	LABOR	3,671,962	1,859,686	8,480	16,653	965	9	2,358	139,747
195	TI	[TI] 410 + 411 - OPEB	LABOR	105,080,197	53,218,455	242,682	476,553	27,621	272	67,466	3,999,130
196	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0
197	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0
198	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0	0
199	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0
200	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	108,083	42,542	260	1,938	3,282	14	34	3,922

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	TI	[TI] 410 + 411 - Deduction for Retention Payments (c)	LABOR	1	88	947	1,001	176	145	39
152	TI	[TI] 410 + 411 - Deferred Employer ER FICA	LABOR	1,048	116,524	1,253,632	1,325,121	232,723	191,848	52,090
153	TI	[TI] 410 + 411 - FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0
154	TI	[TI] 410 + 411 - Fed Amort of Deferred Gain on Sale of Gener	not_used	0	0	0	0	0	0	0
155	TI	[TI] 410 + 411 - Injuries & Damages - FT	TOTPLT	-65	-4,593	-70,506	-73,560	-13,394	-8,263	-102
156	TI	[TI] 410 + 411 - Line Pack Adjustment	not_used	0	0	0	0	0	0	0
157	TI	[TI] 410 + 411 - Medicare Subsidy	not_used	0	0	0	0	0	0	0
158	TI	[TI] 410 + 411 - Partnership Income/Loss (nc)	TOTPLT	8	589	9,050	9,442	1,719	1,061	13
159	TI	[TI] 410 + 411 - Plant Related	DEPREXP	7,419	519,985	7,995,712	8,329,491	1,517,193	943,298	16,937
160	TI	[TI] 410 + 411 - Previously Deducted Amort - Reacquired Bon	not_used	0	0	0	0	0	0	0
161	TI	[TI] 410 + 411 - R & D Credits CF	TOTPLT	-3	-213	-3,276	-3,418	-622	-384	-5
162	TI	[TI] 410 + 411 - RE - Lease Liability	TOTPLT	47	3,303	50,708	52,904	9,633	5,943	74
163	TI	[TI] 410 + 411 - RE - ROU Lease Asset	TOTPLT	-64	-4,462	-68,503	-71,470	-13,013	-8,028	-99
164	TI	[TI] 410 + 411 - Real Estate Taxes (nc)	TOTPLT	-208	-14,633	-224,653	-234,385	-42,677	-26,329	-326
165	TI	[TI] 410 + 411 - Reversal of Book Income from Partnerships	TOTPLT	-8	-589	-9,050	-9,442	-1,719	-1,061	-13
166	TI	[TI] 410 + 411 - Severance Pay (nc)	LABOR	-23	-2,543	-27,363	-28,923	-5,080	-4,187	-1,137
167	TI	[TI] 410 + 411 - State NOL CF (c)	DEPREXP	-3,561	-249,619	-3,838,336	-3,998,567	-728,327	-452,830	-8,130
168	TI	[TI] 410 + 411 - Unrealized G/L on Equity Securities	TOTPLT	-25	-1,753	-26,907	-28,073	-5,112	-3,154	-39
169	TI	**[TI] E410 + E411- PROVISION FOR DEFERRED INCOME T**								
170	TI	[TI] E410 + E411 - Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0
171	TI	[TI] E410 + E411 - Tax Depreciation	DEPREXP	0	0	0	0	0	0	0
172	TI	[TI] 410 + 411 - Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0
173	TI	[TI] E410 + E411 - Amortization of Power Gain	not_used	0	0	0	0	0	0	0
174	TI	[TI] E410 + E411 - Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0
175	TI	[TI] 410 + 411 - Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0
176	TI	[TI] 410 + 411 - AFUDC / IDC - Debt	TOTPLT	214	15,052	231,081	241,092	43,898	27,083	335
177	TI	[TI] 410 + 411 - Capitalized Interest - Section 263A	TOTPLT	-669	-47,020	-721,862	-753,134	-137,132	-84,602	-1,048
178	TI	[TI] 410 + 411 - Cost of removal	TOTPLT	0	0	0	0	0	0	0
179	TI	[TI] E410 + E411 - Utility Commodity Costs	not_used	0	0	0	0	0	0	0
180	TI	[TI] E410 + E411 - RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0
181	TI	[TI] E410 + E411 - SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0
182	TI	[TI] 410 + 411 - Def Comp - Off/Dir/NOC (c)	LABOR	-2	-182	-1,956	-2,068	-363	-299	-81
183	TI	[TI] 410 + 411 - Deduction of Securitizartion	not_used	0	0	0	0	0	0	0
184	TI	[TI] 410 + 411 - Additional Vacation Pay Adj (c)	LABOR	51	5,668	60,976	64,453	11,319	9,331	2,534
185	TI	[TI] 410 + 411 - Third Party Claims	TOTPLT	-17	-1,221	-18,747	-19,559	-3,561	-2,197	-27
186	TI	[TI] E410 + E411 - Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0
187	TI	[TI] E410 + E411 - Deduction for New Network Meter Equipme	TOTPLT	0	0	0	0	0	0	0
188	TI	[TI] 410 + 411 - Gain/loss bond reacq	not_used	0	0	0	0	0	0	0
189	TI	[TI] 410 + 411 - Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0
190	TI	[TI] 410 + 411 - Defer Dividend Equivalents/Restricted Stock-T	LABOR	0	0	0	0	0	0	0
191	TI	[TI] E410 + E411 - Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0
192	TI	[TI] 410 + 411 - CIAC Tax Gross Up	TOTPLTNET	-184	-13,021	-194,958	-206,651	-38,128	-24,219	-158
193	TI	[TI] E410 + E411 - FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0
194	TI	[TI] 410 + 411 - Pension	LABOR	543	60,376	649,562	686,604	120,584	99,405	26,990
195	TI	[TI] 410 + 411 - OPEB	LABOR	15,537	1,727,781	18,588,450	19,648,470	3,450,749	2,844,653	772,378
196	TI	[TI] 410 + 411 - Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0
197	TI	[TI] E410 + E411 - Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0
198	TI	[TI] 410 + 411 - Rabbi Trust	LABOR	0	0	0	0	0	0	0
199	TI	[TI] E410 + E411 - FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0
200	TI	[TI] 410 + 411 - Additional Expenses on Rental Property	TOTPLT	22	1,511	23,198	24,203	4,407	2,719	34

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
201	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	1,045,327	529,412	2,414	4,741	275	3	671	39,783
202	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0
203	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0
205	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-66,348	-26,115	-160	-1,190	-2,015	-9	-21	-2,408
206	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-52,458	-20,648	-126	-941	-1,593	-7	-16	-1,904
207	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-6,684,538	-3,868,705	-19,086	-32,542	-613	-9	-8,323	-23,891
208	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0
209	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-91,151	-36,019	-210	-1,348	-2,094	-9	-28	-3,410
211	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0	0
212	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0	0
215	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	328,125	129,661	755	4,851	7,538	32	102	12,274
216	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0
217	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-401,853	-158,795	-925	-5,941	-9,232	-39	-125	-15,032
218	TI										
219	TI										
220	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**									
221	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**									
222	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-107,143	-42,338	-247	-1,584	-2,461	-10	-33	-4,008
223	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET								
224	TI	**[TI] TOTAL DEFERRED INCOME TAX**		144,525,616	68,877,750	334,262	1,130,425	1,113,608	4,900	77,753	5,657,838
225	TI										
226	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0
227	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0
229	TI										
230	TI	**[TI] OPERATING INCOME ADJUSTED**		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
201	TI	[TI] 410 + 411 - Performance Incentive Plan Adj (c)	LABOR	155	17,188	184,916	195,461	34,328	28,298	7,684
202	TI	[TI] 410 + 411 - Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0
203	TI	[TI] 410 + 411 - Misc	TOTPLT	0	0	0	0	0	0	0
204	TI	[TI] 410 + 411 - Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0
205	TI	[TI] E410 + E411 - Clause - Deferred Return on CIP II	TOTPLT	-13	-928	-14,240	-14,857	-2,705	-1,669	-21
206	TI	[TI] E410 + E411 - Clause - Deferred Depreciation on CIP II	TOTPLT	-10	-733	-11,259	-11,747	-2,139	-1,320	-16
207	TI	[TI] 410 + 411 - Customer Connection Fees (Contributions in /	CUSTACCTS	-1,025	-43,067	-1,309,422	-799,641	-175,856	-273,828	-128,530
208	TI	[TI] E410 + E411 - Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0
209	TI	[TI] 410 + 411 - Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0
210	TI	[TI] 410 + 411 - Assessment by Board of Public Utilities of the	TOTPLTNET	-18	-1,310	-19,619	-20,796	-3,837	-2,437	-16
211	TI	[TI] E410 + E411 - Casualty Loss Deferred O&M & Ins Procee	TOTPLTNET	0	0	0	0	0	0	0
212	TI	[TI] E410 + E411 - GainState LILOAudit Refunds not yet recei	TOTPLTNET	0	0	0	0	0	0	0
213	TI	[TI] E410 + E411 - LCAPP	TOTPLTNET	0	0	0	0	0	0	0
214	TI	[TI] E410 + E411 - Audit Adjustment	not_used	0	0	0	0	0	0	0
215	TI	[TI] 410 + 411 - Stock-Based Compensation - Reverse Book -	TOTPLTNET	67	4,717	70,625	74,861	13,812	8,773	57
216	TI	[TI] 410 + 411 - Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0
217	TI	[TI] 410 + 411 - Legal Reserves (nc)	TOTPLTNET	-82	-5,777	-86,494	-91,682	-16,915	-10,745	-70
218	TI									
219	TI									
220	TI	**[TI] DEVELOPMENT OF OPERATING INCOME ADJ CONTI**								
221	TI	**[TI] E410 + E411- PROVISION FOR DEFER INC TAX CONT**								
222	TI	[TI] E410 + E411 - Material & Supplies Reserve (c)	TOTPLTNET	-22	-1,540	-23,061	-24,445	-4,510	-2,865	-19
223	TI	[TI] E410 + E411 - Medicare Subsidy	TOTPLTNET							
224	TI	**[TI] TOTAL DEFERRED INCOME TAX**		23,050	2,355,466	26,716,640	28,691,924	5,049,155	3,746,112	746,733
225	TI									
226	TI	**[TI] TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0
227	TI	**[TI] TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0
228	TI	**[TI] TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0
229	TI									
230	TI	**[TI] OPERATING INCOME ADJUSTED**		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**									
2	LR										
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
4	LR										
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0
6	LR										
7	LR	**DISTRIBUTION LABOR EXPENSE**									
8	LR	Operation									
9	LR	582-Station Equipment	E367PLT	280,636	121,848	602	1,539	27	0	96	1,683
10	LR	583-Overhead Lines	E367PLT	941,919	408,969	2,021	5,167	92	0	322	5,649
11	LR	584-Underground Lines	E367PLT	4,591,058	1,993,377	9,849	25,185	447	2	1,571	27,534
12	LR	586-Metering	MTROMMIN_07	4,311,826	2,160,954	7,507	12,543	2,057	32	853	
13	LR	587-Customer Installations	MTROMMIN_07	17,308,754	8,674,612	30,136	50,349	8,258	129	3,423	
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	8,017,775	34,598	81,316	4,429	58	5,150	179,048
15	LR	Total Operation		43,603,802	21,377,534	84,714	176,100	15,310	222	11,416	213,914
16	LR	Maintenance									
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	1,010,552	5,066	12,747	21	0	800	10,392
19	LR	592-Station Equipment	E362PLT	8,699,368	3,434,239	17,216	43,320	73	1	2,718	35,315
20	LR	593-Overhead Lines	E365PLT	11,294,340	4,717,949	23,243	59,144	95	1	3,717	54,978
21	LR	594-Underground Lines	E367PLT	11,333,758	4,920,968	24,315	62,174	1,104	5	3,879	67,972
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	1,754,504	13,306	11,147			2,347	7,614
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	218,284	1,372	10,605	18,141	77	172	5,373,344
24	LR	597-Meters	MTROMMIN_07	700,642	351,140	1,220	2,038	334	5	139	
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	199,108	983	2,489	13	0	156	37,370
26	LR	Total Maintenance		45,417,214	16,606,745	86,721	203,665	19,783	90	13,927	5,586,984
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	37,984,279	171,434	379,765	35,092	312	25,342	5,800,898
28	LR										
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	33,971,151	167,594	285,748	5,380	82	73,088	209,786
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	4,371,290	14,761	26,931	976	14	1,718	12,046
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP								
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	5,748,870	4,203,182	13,436	28,675	349	3	1,940	28,733
33	LR	**Employee Pension/Benefits Acct E926**	LABOR								
34	LR										
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	80,529,903	367,225	721,118	41,797	411	102,089	6,051,463

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**								
2	LR									
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
4	LR									
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0
6	LR									
7	LR	**DISTRIBUTION LABOR EXPENSE**								
8	LR	Operation								
9	LR	582-Station Equipment	E367PLT	65	763	65,653	73,364	11,548	3,446	
10	LR	583-Overhead Lines	E367PLT	218	2,561	220,357	246,237	38,759	11,567	
11	LR	584-Underground Lines	E367PLT	1,061	12,481	1,074,055	1,200,199	188,917	56,377	
12	LR	586-Metering	MTROMMIN_07			297,894	1,653,831	137,755	33,846	4,554
13	LR	587-Customer Installations	MTROMMIN_07			1,195,820	6,638,894	552,985	135,867	18,282
14	LR	588-Miscellaneous	DISTEXPO	2,790	55,243	3,366,985	3,310,466	706,641	389,142	15,969
15	LR	Total Operation		4,134	71,047	6,220,765	13,122,993	1,636,605	630,244	38,805
16	LR	Maintenance								
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	562	5,044	544,301	615,354	168,589	186,430	
19	LR	592-Station Equipment	E362PLT	1,909	17,143	1,849,739	2,091,205	572,930	633,561	
20	LR	593-Overhead Lines	E365PLT	2,496	47,866	2,542,050	2,835,825	738,051	268,926	
21	LR	594-Underground Lines	E367PLT	2,620	30,811	2,651,477	2,962,884	466,373	139,176	
22	LR	595-Line Transformers	LNTRFRMR_04	347	3,317	344,093	320,906			
23	LR	596-Street Lighting and Signal Systems	E373PLT	118	1,929,677	120,485	131,861	23,703	14,525	
24	LR	597-Meters	MTROMMIN_07			48,406	268,736	22,384	5,500	740
25	LR	598-Other Distribution Maintenance	DISTEXPM	1,567	17,501	107,234	118,988	27,799	16,090	3
26	LR	Total Maintenance		9,618	2,051,358	8,207,784	9,345,758	2,019,828	1,264,208	743
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		13,752	2,122,405	14,428,550	22,468,751	3,656,434	1,894,452	39,548
28	LR									
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	9,002	378,175	11,498,057	7,021,662	1,544,190	2,404,487	1,128,624
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	223	35,938	913,560	146,473	12,444	3,166	382
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP							
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	534	77,950	1,287,784	95,083	8,588	2,409	204
33	LR	**Employee Pension/Benefits Acct E926**	LABOR							
34	LR									
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		23,511	2,614,469	28,127,951	29,731,969	5,221,656	4,304,516	1,168,758

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**									
2	CA										
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0
5	CA										
6	CA	**TRANSMISSION PLANT**									
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
16	CA										
17	CA	**DISTRIBUTION PLANT**									
18	CA	E360 Land and Land Rights	E360PLT	3,481,598	1,374,426	6,890	17,337	29	0	1,088	14,133
19	CA	E361 Structures and Improvements	E361PLT	1,433,350	565,842	2,837	7,138	12	0	448	5,819
20	CA	E362 Station Equipment	E362PLT	72,557,752	28,643,535	143,592	361,316	608	7	22,669	294,546
21	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	36,503,668	181,672	459,269	759	9	28,834	1,050,922
22	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	98,173,497	483,650	1,230,697	1,983	24	77,336	1,144,003
23	CA	E366 Underground Conduits	E367PLT	3,221,386	1,398,683	6,911	17,672	314	2	1,102	19,320
24	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	14,244,691	70,383	179,975	3,196	16	11,228	196,758
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	48,751,051	20,636,869	140,946	294,209	882	11	17,926	427,195
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	44,108,093	22,014,084	70,880	242,003	0	0	15,745	0
27	CA	E369 Services	E369PLT	11,962,969	18,747	118,021	3,200,191	7,381,213	31,321	0	0
28	CA	E370 Meters	METERPLT	73,420,491	44,077,472	153,129	255,835	34,425	537	17,392	0
29	CA	E373 Street Lighting	E373PLT	39,887,684	1,110,233	6,979	53,941	92,270	392	876	27,329,799
30	CA	E374 Asset Retirement Obligations	TOTPLT								
31	CA	TOTAL DISTRIBUTION PLANT		653,152,020	268,761,746	1,385,889	6,319,583	7,515,690	32,319	194,644	30,482,494
32	CA										
33	CA	**TOTAL CAPITAL ADDITIONS**		653,152,020	268,761,746	1,385,889	6,319,583	7,515,690	32,319	194,644	30,482,494

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**								
2	CA									
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0
5	CA									
6	CA	**TRANSMISSION PLANT**								
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0
16	CA									
17	CA	**DISTRIBUTION PLANT**								
18	CA	E360 Land and Land Rights	E360PLT	764	6,861	740,289	836,927	229,294	253,559	0
19	CA	E361 Structures and Improvements	E361PLT	315	2,825	304,772	344,557	94,399	104,389	0
20	CA	E362 Station Equipment	E362PLT	15,921	142,980	15,427,894	17,441,855	4,778,566	5,284,262	0
21	CA	E364 Poles Towers and Fixtures	E364PLT	19,880	331,155	19,664,352	22,108,018	3,275,933	2,877,049	0
22	CA	E365 OH Conductors and Dev.	E365PLT	51,934	996,016	52,896,263	59,009,287	15,357,744	5,595,947	0
23	CA	E366 Underground Conduits	E367PLT	745	8,757	753,627	842,138	132,557	39,558	0
24	CA	E367 Underground Cond. and Dev.	E367PLT	7,585	89,188	7,675,211	8,576,638	1,350,005	402,871	0
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	23,092	207,372	11,034,433	15,968,117	0	0	0
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	0	0	11,942,383	9,822,999	0	0	0
27	CA	E369 Services	E369PLT	0	0	1,185,393	22,642	5,432	9	0
28	CA	E370 Meters	METERPLT	0	0	23,017,806	3,559,858	1,674,542	568,888	60,608
29	CA	E373 Street Lighting	E373PLT	598	9,814,684	612,810	670,667	120,557	73,879	0
30	CA	E374 Asset Retirement Obligations	TOTPLT							
31	CA	TOTAL DISTRIBUTION PLANT		120,834	11,599,838	145,255,234	139,203,702	27,019,028	15,200,411	60,608
32	CA									
33	CA	**TOTAL CAPITAL ADDITIONS**		120,834	11,599,838	145,255,234	139,203,702	27,019,028	15,200,411	60,608

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AF	**ALLOCATION FACTOR TABLE**									
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AF										
4	AF	**ALLOCATION FACTORS PART A**									
5	AF										
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	2,000,647	6,950	11,612	0	0	0	0
7	AF										
8	AF										
9	AF	CP @ secondary lines - local	CP_SEC_04	8,231,675	4,108,379	13,228	45,164	0	0	2,938	0
10	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	3,519,017	1,384,625	4,458	15,221	0	0	990	0
11	AF	CP @ primary lines - systems	CP_PRI_05	8,928,659	4,218,210	13,582	46,371	0	0	3,017	0
12	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	21,256,013	12,306,251	68,333	102,324	0	0	31,834	67,596
13	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,856,464	12,146,933	67,448	100,999	0	0	31,422	66,721
14	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	11,830,661	65,692	98,370	0	0	30,604	64,983
15	AF										
16	AF										
17	AF	CP @ primary lines - local	CP_PRI_04	8,928,659	4,218,210	13,582	46,371	0	0	3,017	0
18	AF	NCP @ meter - local	NCP_MTR_04	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
19	AF	NCP @ meter - measurement	NCP_MTR_07	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
20	AF	NCP @ meter - cust svs	NCP_MTR_06	10,800,203	4,443,011	33,669	58,231	1,244	19	25,942	66,269
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	10,698,184	4,443,011	33,669	58,231	1,244	19	25,942	0
22	AF										
23	AF	**BILLING DETERMINANTS**									
24	AF										
25	AF	Number of Customers		2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
26	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	13,286,613,062	93,109,748	189,891,666	581,366	7,149	11,877,324	283,298,553
27	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0
28	AF										
29	AF										
30	AF	**ALLOCATION FACTORS PART B**									
31	AF										
32	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
33	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	0
34	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	12,282,908,123	2,946,792,247	20,126,052	42,010,913	125,919	1,539	2,559,633	61,000,231
35	AF	Delivery kWh @ primary - System E	KWH_PRI_09	36,303,573,183	14,051,414,693	95,968,591	200,323,847	600,430	7,341	12,205,294	290,872,062
36	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	36,303,573,183	14,051,414,693	95,968,591	200,323,847	600,430	7,341	12,205,294	290,872,062
37	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	32,329,765,823	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
38	AF	Delivery kWh @ meter - measurement	KWHMETER_07	40,781,263,034	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
39	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	40,781,263,034	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
40	AF										
41	AF										
42	AF	**ALLOCATION FACTORS PART C**									
43	AF										
44	AF	Draft EC Proforma	ECPRO_07	434,841,736	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
45	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	100	1	1	1	1	1	1
46	AF	E587 Customer Installation Expenses System	CUSINT_05	112	100	1	1	1	1	1	1
47	AF	E369 minimum Service investment- access	SERVICESMIN_03	360,747,418	565,325	3,558,965	96,502,862	222,582,987	944,498	0	0
48	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	709,786,184	312,686,346	245,199,879	1,436,410	2,399,832	12,866	0	0
49	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938
50	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	2,000,647	6,950	11,612	662	10	789	4,938

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AF	**ALLOCATION FACTOR TABLE**								
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AF									
4	AF	**ALLOCATION FACTORS PART A**								
5	AF									
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0	0	288,392	9,532	794	195	26
7	AF									
8	AF									
9	AF	CP @ secondary lines - local	CP_SEC_04	0	0	2,228,748	1,833,218	0	0	0
10	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0	0	751,143	617,840	156,550	588,188	0
11	AF	CP @ primary lines - systems	CP_PRI_05	0	0	2,288,330	1,882,226	476,925	0	0
12	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	3,223	33,220	3,731,290	3,009,831	762,998	1,139,114	0
13	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	3,181	32,790	3,682,984	2,970,865	753,120	0	0
14	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	3,098	31,936	3,587,089	2,893,512	753,120	1,139,114	0
15	AF									
16	AF									
17	AF	CP @ primary lines - local	CP_PRI_04	0	0	2,288,330	1,882,226	476,925	0	0
18	AF	NCP @ meter - local	NCP_MTR_04	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
19	AF	NCP @ meter - measurement	NCP_MTR_07	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
20	AF	NCP @ meter - cust svs	NCP_MTR_06	3,582	32,169	2,324,426	2,007,606	519,576	871,481	412,980
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	0	0	2,324,426	2,007,606	519,576	871,481	412,980
22	AF									
23	AF	**BILLING DETERMINANTS**								
24	AF									
25	AF	Number of Customers		90	23,580	288,392	9,532	794	195	26
26	AF	Delivered kWh @ Meter - annual (w/n net)		15,313,401	137,520,699	7,289,563,210	10,497,945,935	3,083,571,353	4,669,504,753	672,466,899
27	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0
28	AF									
29	AF									
30	AF	**ALLOCATION FACTORS PART B**								
31	AF									
32	AF	Delivery kWh @ meter	KWHMETER_04	15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
33	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0	0	7,352,369,374	0	0	0	0
34	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	3,297,302	29,611,145	1,575,635,361	2,280,128,917	652,114,111	4,669,504,753	0
35	AF	Delivery kWh @ primary - System E	KWH_PRI_09	15,722,779	141,197,084	7,513,222,517	10,872,512,987	3,109,525,559	0	0
36	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	15,722,779	141,197,084	7,513,222,517	10,872,512,987	3,109,525,559	0	0
37	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	15,313,401	137,520,699	7,317,598,845	10,589,422,620	0	0	0
38	AF	Delivery kWh @ meter - measurement	KWHMETER_07	15,313,401	137,520,699	7,317,598,845	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
39	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	15,313,401	137,520,699	7,317,598,845	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
40	AF									
41	AF									
42	AF	**ALLOCATION FACTORS PART C**								
43	AF									
44	AF	Draft EC Proforma	ECPRO_07	0	0	50,271,203	0	0	0	0
45	AF	E587 Customer Installation Expenses Local	CUSINT_04	1	1	1	1	1	0	1
46	AF	E587 Customer Installation Expenses System	CUSINT_05	1	1	1	1	1	0	1
47	AF	E369 minimum Service investment- access	SERVICESMIN_03	0	0	35,745,941	682,770	163,790	280	0
48	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	0	0	138,224,973	9,042,819	366,892	416,167	0
49	AF	Avg Customer Bills - local	CUSTAVG_04	90	23,580	288,392	9,532	794	195	26
50	AF	Avg Customer Bills - cust svs	CUSTAVG_06	90	23,580	288,392	9,532	794	195	26

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AF	E370 minimum meter investment - measurement	METERSMIN_07	191,661,323	110,732,227	384,693	642,713	430,290	6,712	43,693	0
52	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	399,712,164	3,031,461	2,539,460	0	0	534,622	1,734,652
53	AF	Billing Function costs - cust svs	BILLING_06	130,951	94,645	329	549	6	0	7	397
54	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
57	AF										
58	AF	Avg Customer Bills - measurement	CUSTAVG_07	2,335,622	2,000,647	6,950	11,612	662	10	789	4,938
59	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	67,106,800	233,135	389,502	21,207	331	25,273	19,139
60	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	16,168,305	56,170	93,844	1,071	17	1,276	0
61	AF	Sales	SALES_06	0	0	0	0	0	0	0	0
62	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	2,438,140	7,794	16,634	202	2	1,125	16,667
63	AF										
64	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
65	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	124,473,055	75,468,893	262,185	438,037	0	0	29,779	0
66	AF										
67	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0
68	AF										
69	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	0	0	0	0	0	0	0
70	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	0	0	0	0	0	0	1
71	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0	0
72	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	0	0	0	0	0	0
73	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0
74	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**									
75	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
76	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	1	0	0	0	0	0	0	0
77	AF										
78	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	0	0	0	0	0
79	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	3,201,035	11,121	18,579	3,047	48	1,263	0
80	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0
81	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0
82	AF	Meter O&M - measurement	METERPLT_07	456,573,728	380,825,641	1,226,966	2,049,910	323,611	5,048	139,357	0
83	AF										
84	AF	E370 excess meter investment - dummy	METERSEXC_08	5,064	0	0	0	0	0	0	0
85	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0
86	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0
87	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0
88	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0
89	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0
90	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0
91	AF										
92	AF										
93	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0
94	AF										
95	AF										
96	AF	**Plant Related**									
97	AF	Distribution Plant Total	DISTPLT	10,773,828,418	4,210,219,934	25,847,331	195,170,040	331,843,556	1,410,730	3,235,061	395,999,604
98	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	3,990,841,758	25,085,193	193,896,724	331,672,221	1,408,057	3,148,498	395,999,604
99	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	20,257,231	101,551	255,529	430	5	16,032	208,308
100	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	95,635,281	479,427	1,206,364	2,030	25	75,688	983,432

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AF	E370 minimum meter investment - measurement	METERSMIN_07	0	0	66,256,263	7,189,292	1,876,806	3,341,065	757,571
52	AF	E368 Line Transfomers - local	LNTRFRMR_04	79,064	755,659	78,391,489	73,109,064	0	0	0
53	AF	Billing Function costs - cust svs	BILLING_06	7	1,896	23,193	8,966	747	183	25
54	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	0	0	37,965,488	6,395,819	3,266,582	646,271	0
55	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
56	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
57	AF									
58	AF	Avg Customer Bills - measurement	CUSTAVG_07	90	23,580	275,795	9,532	794	195	26
59	AF	Account Maint - cust svs	ACCTMAINT_06	348	91,387	10,058,899	2,365,984	197,074	48,420	6,515
60	AF	Meter Reading Costs - measurement	MRCOST_07	0	0	3,962,103	231,110	19,250	4,730	636
61	AF	Sales	SALES_06	0	0	0	0	0	0	0
62	AF	Other Utility work by Cust Ops - local	UTILWORK_04	310	45,217	747,005	55,155	4,982	1,398	118
63	AF									
64	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	0	0	37,965,488	6,395,819	3,266,582	646,271	0
65	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	0	0	37,965,488	6,395,819	3,266,582	646,271	0
66	AF									
67	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0
68	AF									
69	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	0	1	0	0	0	0	0
70	AF	Direct - BPL - streetlighting	DIR_BPL_02	0	0	0	0	0	0	0
71	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	0	0	0	0	0	0
72	AF	Direct - HTS-HV - access	DIR_HTSHV_03	0	0	0	0	0	0	1
73	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0
74	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**								
75	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
76	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	0	0	0	0	0	1	0
77	AF									
78	AF	Direct - HTS-Sub - local	DIR_HTSS_04	0	0	0	0	0	1	0
79	AF	Meter O&M - minimum - measurement	MTROMMIN_07	0	0	441,272	2,449,831	204,058	50,136	6,746
80	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0
81	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0
82	AF	Meter O&M - measurement	METERPLT_07	0	0	61,413,169	5,406,906	1,411,504	2,512,740	1,258,876
83	AF									
84	AF	E370 excess meter investment - dummy	METERSEXC_08	0	0	0	0	5,064	0	0
85	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0
86	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0
87	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0
88	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0
89	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0
90	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0
91	AF									
92	AF									
93	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0
94	AF									
95	AF									
96	AF	**Plant Related**								
97	AF	Distribution Plant Total	DISTPLT	2,149,976	151,697,776	2,317,368,080	2,428,498,049	441,689,675	268,396,952	301,654
98	AF	Distribution Plant x meters	DISTPLTXMTR	2,149,976	151,697,776	2,202,806,060	2,410,780,266	433,355,304	265,565,538	0
99	AF	Acct E360 - Land & Land Rights	E360PLT	11,260	101,118	10,910,889	12,335,199	3,379,489	3,737,127	0
100	AF	Acct E361 - Structures & Improvments	E361PLT	53,158	477,384	51,510,786	58,235,016	15,954,717	17,643,139	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	617,978,217	3,097,969	7,795,309	13,118	160	489,085	6,354,762
102	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	433,581,460	2,157,854	5,455,077	9,018	110	342,481	12,482,595
103	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	1,193,105,100	5,877,809	14,956,690	24,103	295	939,868	13,903,094
104	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	222,350,106	1,098,632	2,809,297	49,885	248	175,262	3,071,260
105	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	621,400,988	3,070,344	7,851,131	139,414	692	489,805	8,583,237
106	AF	Acct E369 Services	E369PLT	535,269,333	838,818	5,280,717	143,188,891	330,263,894	1,401,425	0	0
107	AF	Acct E370 Meters	METERPLT	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
108	AF										
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	219,378,176	762,138	1,273,316	171,335	2,673	86,562	0
110	AF	Acct E373 - Streetlights	E373PLT	499,027,153	13,889,907	87,308	674,847	1,154,367	4,901	10,958	341,917,862
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000	0.3104	0.0010	0.0034			0.0002	
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000	0.5421	0.0025	0.0051			0.0010	0.0017
113	AF										
114	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	15,974,298	97,668	727,637	1,232,304	5,239	12,759	1,472,729
115	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0	0
116	AF	E391-E398 General Plant	GENPLT	429,584,593	164,713,403	1,035,337	8,002,670	13,689,057	58,115	129,947	16,344,031
117	AF	Common Plant	COMPLT	126,654,044	67,736,462	345,628	1,081,945	1,086,672	4,711	121,195	1,611,631
118	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	232,449,865	1,380,965	9,084,615	14,775,729	62,826	251,142	17,955,662
119	AF										
120	AF	Total Plant	TOTPLT	11,456,990,950	4,509,491,507	27,571,490	205,409,461	347,875,461	1,478,986	3,601,770	415,746,553
121	AF										
122	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	1,206,907,087	8,335,934	81,854,978	155,879,252	662,476	999,183	103,115,208
123	AF	Total Net Plant	TOTPLTNET	8,357,658,252	3,302,584,420	19,235,556	123,554,483	191,996,209	816,510	2,602,586	312,631,345
124	AF										
125	AF										
126	AF	**Revenue Related**									
127	AF	Total Operating Revenue	TOTREV	1,887,985,784	827,236,523	4,421,864	23,994,492	34,566,954	148,276	712,878	66,845,666
128	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
129	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
130	AF										
131	AF	**Expense Related**									
132	AF	Distr Oper Exp	DISTEXPO	52,242,807	25,904,836	111,784	262,726	14,309	188	16,641	578,491
133	AF	Distr Maint Exp	DISTEXPM	123,204,777	46,346,183	228,789	579,365	3,121	25	36,357	8,698,609
134	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	4,196,182	14,170	25,852	936	14	1,649	11,564
135	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
136	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	58,827,143	283,687	485,379	9,588	146	119,187	348,932
137	AF	Sales Expense	SALESEXP	40,922	29,919	96	204	2	0	14	205
138	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	141,278,389	724,630	2,750,111	2,821,629	12,168	164,024	10,934,014
139	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	48,673,923	274,860	1,746,139	2,774,102	11,836	41,121	4,139,185
140	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	54,630,961	269,518	459,527	8,652	132	117,538	337,369
141	AF	O&M + Capital Additions	EXPENDITURES	964,609,657	410,040,135	2,110,519	9,069,693	10,337,319	44,487	358,668	41,416,508
142	AF										
143	AF	Depreciation Expense (total)	DEPREXP	286,771,855	113,247,114	691,247	5,116,873	8,649,117	36,772	92,204	10,344,570
144	AF										
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	116,400,498	49,105,403	269,701	1,621,455	2,453,615	10,492	36,040	4,221,229
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	1,034,603	525,191	2,388	4,548	-51	1	668	39,394
147	AF										
148	AF	**Labor Expense Related**									
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	21,377,534	84,714	176,100	15,310	222	11,416	213,914
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	16,606,745	86,721	203,665	19,783	90	13,927	5,586,984

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AF	Acct E362 - Station Equipment	E362PLT	343,500	3,084,771	332,853,557	376,304,339	103,096,548	114,006,835	0
102	AF	Acct E364 - Poles & Towers	E364PLT	236,131	3,933,380	233,568,272	262,593,524	38,910,712	34,172,869	0
103	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	631,159	12,104,603	642,849,684	717,141,426	186,643,064	68,007,696	0
104	AF	Acct E366 - UG Conduit	E366PLT	118,401	1,392,172	119,804,922	133,875,585	21,072,679	6,288,555	0
105	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	330,894	3,890,698	334,818,356	374,141,583	58,891,734	17,574,600	0
106	AF	Acct E369 Services	E369PLT	0	0	53,039,066	1,013,079	243,028	415	0
107	AF	Acct E370 Meters	METERPLT	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
108	AF									
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	0	0	114,562,020	17,717,782	8,334,371	2,831,414	301,654
110	AF	Acct E373 - Streetlights	E373PLT	7,483	122,789,628	7,666,746	8,390,589	1,508,270	924,286	0
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES			0.1684	0.1385	0.0351	0.3429	
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.0001	0.0008	0.2209	0.1802	0.0457		
113	AF									
114	AF	Acct E301-E303 Intangible Plt	INTANGPLT	8,077	567,388	8,710,604	9,087,957	1,654,747	1,020,878	12,641
115	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0
116	AF	E391-E398 General Plant	GENPLT	88,736	6,260,999	90,916,078	99,499,766	17,885,807	10,960,646	0
117	AF	Common Plant	COMPLT	20,663	1,091,256	25,189,287	18,477,440	3,731,250	4,465,781	1,690,125
118	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	109,399	7,352,255	116,105,365	117,977,206	21,617,058	15,426,426	1,690,125
119	AF									
120	AF	Total Plant	TOTPLT	2,280,224	160,171,869	2,458,974,623	2,565,500,323	467,129,611	288,190,559	3,568,514
121	AF									
122	AF	Total Distribution Plant Reserve	TOTDRESERVE	585,098	40,022,961	660,087,229	658,722,048	115,325,242	64,723,429	2,112,572
123	AF	Total Net Plant	TOTPLTNET	1,695,126	120,148,908	1,798,887,394	1,906,778,275	351,804,368	223,467,130	1,455,942
124	AF									
125	AF									
126	AF	**Revenue Related**								
127	AF	Total Operating Revenue	TOTREV	739,355	27,211,460	390,878,529	385,362,162	73,955,188	48,941,952	2,970,485
128	**AF**	**ALLOCATION PROPORTIONS TABLE CONTINUED**								
129	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**								
130	AF									
131	AF	**Expense Related**								
132	AF	Distr Oper Exp	DISTEXPO	9,013	178,485	10,878,479	10,695,871	2,283,104	1,257,287	51,594
133	AF	Distr Maint Exp	DISTEXPM	364,664	4,073,681	24,960,676	27,696,698	6,470,625	3,745,275	709
134	AF	Cust Serv & Info Expense	CUSTS_I	214	34,498	876,964	140,606	11,945	3,040	367
135	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
136	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	14,690	642,664	19,367,650	11,432,543	2,495,247	3,869,834	1,815,372
137	AF	Sales Expense	SALESEXP	4	555	9,167	677	61	17	1
138	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	406,726	5,323,015	65,767,731	56,873,087	13,274,358	9,692,791	1,434,962
139	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	25,972	1,650,150	23,808,289	21,049,266	4,466,475	2,860,461	140,326
140	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	14,476	608,165	18,490,686	11,291,938	2,483,301	3,866,794	1,815,005
141	AF	O&M + Capital Additions	EXPENDITURES	527,560	16,922,853	211,022,965	196,076,789	40,293,386	24,893,202	1,495,571
142	AF									
143	AF	Depreciation Expense (total)	DEPREXP	57,030	3,997,233	61,464,680	64,030,515	11,662,973	7,251,328	130,196
144	AF									
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	26,005	1,627,834	24,487,235	24,966,650	4,640,740	2,918,281	15,819
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	152	17,038	182,614	193,060	33,890	28,029	7,680
147	AF									
148	AF	**Labor Expense Related**								
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	4,134	71,047	6,220,765	13,122,993	1,636,605	630,244	38,805
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	9,618	2,051,358	8,207,784	9,345,758	2,019,828	1,264,208	743

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AF	Total Labor	LABOR	159,006,836	80,529,903	367,225	721,118	41,797	411	102,089	6,051,463
152	AF										
153	AF	**REVENUES AND BILLING DETERMINANTS**									
154	AF										
155	AF	Base Rate Sales Revenue	SALESREV	1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
156	AF										
157	AF	Residential Service	REVRS	817,837,432	817,837,432	0	0	0	0	0	0
158	AF	Residential Heating Service	REVRHS	4,371,623	0	4,371,623	0	0	0	0	0
159	AF	Residential Load Management Service	REVRLM	23,721,865	0	0	23,721,865	0	0	0	0
160	AF	Water Heating Service	REVWH	34,174,203	0	0	0	34,174,203	0	0	0
161	AF	Water Heating Storage Service	REVWHS	146,591	0	0	0	0	146,591	0	0
162	AF	Building Heating Service	REVHS	701,978	0	0	0	0	0	701,978	0
163	AF	Body Police Lighting Service	REVBLP	66,086,163	0	0	0	0	0	0	66,086,163
164	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	730,955	0	0	0	0	0	0	0
165	AF	Private Street and Area Lighting Service	REVPAL	26,795,398	0	0	0	0	0	0	0
166	AF	General Power and Lighting Service	REVGLP	384,902,021	0	0	0	0	0	0	0
167	AF	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	0	0	0	0	0	0
168	AF	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	0	0	0	0	0	0
169	AF	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	0	0	0	0	0	0
170	AF	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	0	0	0	0	0
171	AF	HEP	REVHEP	0	0	0	0	0	0	0	0
172	AF										
173	AF										
174	AF	Total Rev Req @ desired ROR	REVREQ	1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
175	AF										
176	AF										
177	AF	**PRESENT REVENUES FROM SALES INPUT**									
178	AF										
179	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0
180	AF	Sales of Electricity Revenues - Rates		1,254,696,745	597,284,000	4,407,000	7,778,000	52,355	161	740,000	56,059,000
181	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0
182	AF										
183	AF	**RATE OF RETURN**									
184	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
185	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	0	7,136	111	0	0
186	AF	Expense Reclassification-local	ADJEXP_04	-17,563	-10,963	-42	-77	0	0	-7	-674

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AF	Total Labor	LABOR	23,511	2,614,469	28,127,951	29,731,969	5,221,656	4,304,516	1,168,758
152	AF									
153	AF	**REVENUES AND BILLING DETERMINANTS**								
154	AF									
155	AF	Base Rate Sales Revenue	SALESREV	730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
156	AF									
157	AF	Residential Service	REVRS	0	0	0	0	0	0	0
158	AF	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
159	AF	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
160	AF	Water Heating Service	REVWH	0	0	0	0	0	0	0
161	AF	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
162	AF	Building Heating Service	REVHS	0	0	0	0	0	0	0
163	AF	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
164	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	730,955	0	0	0	0	0	0
165	AF	Private Street and Area Lighting Service	REVPAL	0	26,795,398	0	0	0	0	0
166	AF	General Power and Lighting Service	REVGLP	0	0	384,902,021	0	0	0	0
167	AF	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	379,469,998	0	0	0
168	AF	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	72,824,417	0	0
169	AF	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	48,193,633	0
170	AF	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	2,925,067
171	AF	HEP	REVHEP	0	0	0	0	0	0	0
172	AF									
173	AF									
174	AF	Total Rev Req @ desired ROR	REVREQ	730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
175	AF									
176	AF									
177	AF	**PRESENT REVENUES FROM SALES INPUT**								
178	AF									
179	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0
180	AF	Sales of Electricity Revenues - Rates		322,229	27,815,000	264,859,000	223,909,000	38,961,000	30,175,000	2,335,000
181	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0
182	AF									
183	AF	**RATE OF RETURN**								
184	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
185	AF	Expense Reclassification Plus-local	ADJ_Plus_04	0	0	0	0	0	0	10,316
186	AF	Expense Reclassification-local	ADJEXP_04	-1	-283	-2,947	-1,955	-350	-262	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AP	**ALLOCATION PROPORTIONS TABLE**									
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
3	AP										
4	AP	**ALLOCATION FACTORS PART A**									
5	AP										
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.863036	0.002998	0.005009	0.000000	0.000000	0.000000	0.000000
7	AP										
8	AP										
9	AP	CP @ secondary lines - local	CP_SEC_04	1.000000	0.499094	0.001607	0.005487	0.000000	0.000000	0.000357	0.000000
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000	0.393469	0.001267	0.004325	0.000000	0.000000	0.000281	0.000000
11	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.472435	0.001521	0.005194	0.000000	0.000000	0.000338	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	1.000000	0.578954	0.003215	0.004814	0.000000	0.000000	0.001498	0.003180
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.611737	0.003397	0.005086	0.000000	0.000000	0.001582	0.003360
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.577157	0.003205	0.004799	0.000000	0.000000	0.001493	0.003170
15	AP										
16	AP	CP @ primary lines - local	CP_PRI_04	1.000000	0.472435	0.001521	0.005194	0.000000	0.000000	0.000338	0.000000
17	AP	NCP @ meter - local	NCP_MTR_04	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
18	AP	NCP @ meter - measurement	NCP_MTR_07	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
19	AP	NCP @ meter - cust svs	NCP_MTR_06	1.000000	0.411382	0.003117	0.005392	0.000115	0.000002	0.002402	0.006136
20	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	1.000000	0.415305	0.003147	0.005443	0.000116	0.000002	0.002425	0.000000
21	AP	**BILLING DETERMINANTS**									
22	AP										
23	AP	Number of Customers									
24	AP	Delivered kWh @ Meter - annual (w/n net)									
25	AP	Delivered Kw @ Meter - annual									
26	AP										
27	AP	**ALLOCATION FACTORS PART B**									
28	AP										
29	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.335298	0.002290	0.004780	0.000014	0.000000	0.000291	0.006941
30	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.641341	0.004380	0.009143	0.000027	0.000000	0.000557	0.000000
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	1.000000	0.239910	0.001639	0.003420	0.000010	0.000000	0.000208	0.004966
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	1.000000	0.387053	0.002644	0.005518	0.000017	0.000000	0.000336	0.008012
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	1.000000	0.387053	0.002644	0.005518	0.000017	0.000000	0.000336	0.008012
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	1.000000	0.423311	0.002891	0.006035	0.000018	0.000000	0.000368	0.008763
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	1.000000	0.335584	0.002292	0.004784	0.000014	0.000000	0.000291	0.006947
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	1.000000	0.335584	0.002292	0.004784	0.000014	0.000000	0.000291	0.006947
37	AP										
38	AP										
39	AP	**ALLOCATION FACTORS PART C**									
40	AP										
41	AP	Draft EC Proforma	ECPRO_07	1.000000	0.875780	0.002822	0.004714	0.000744	0.000012	0.000320	0.000000
42	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
43	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.892857	0.008929	0.008929	0.008929	0.008929	0.008929	0.008929
44	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.001567	0.009866	0.267508	0.617005	0.002618	0.000000	0.000000
45	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	1.000000	0.440536	0.345456	0.002024	0.003381	0.000018	0.000000	0.000000
46	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
47	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.851985	0.002960	0.004945	0.000282	0.000004	0.000336	0.002103
48	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.577749	0.002007	0.003353	0.002245	0.000035	0.000228	0.000000
49	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.713915	0.005414	0.004536	0.000000	0.000000	0.000955	0.003098
50	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.722749	0.002511	0.004195	0.000048	0.000001	0.000057	0.003033

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	AP	**ALLOCATION PROPORTIONS TABLE**								
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
3	AP									
4	AP	**ALLOCATION FACTORS PART A**								
5	AP									
6	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	0.000000	0.000000	0.124406	0.004112	0.000343	0.000084	0.000011
7	AP									
8	AP									
9	AP	CP @ secondary lines - local	CP_SEC_04	0.000000	0.000000	0.270753	0.222703	0.000000	0.000000	0.000000
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	0.000000	0.000000	0.213453	0.175572	0.044487	0.167146	0.000000
11	AP	CP @ primary lines - systems	CP_PRI_05	0.000000	0.000000	0.256290	0.210807	0.053415	0.000000	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	0.000152	0.001563	0.175540	0.141599	0.035896	0.053590	0.000000
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	0.000160	0.001651	0.185480	0.149617	0.037928	0.000000	0.000000
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	0.000151	0.001558	0.174996	0.141159	0.036741	0.055571	0.000000
15	AP									
16	AP	CP @ primary lines - local	CP_PRI_04	0.000000	0.000000	0.256290	0.210807	0.053415	0.000000	0.000000
17	AP	NCP @ meter - local	NCP_MTR_04	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
18	AP	NCP @ meter - measurement	NCP_MTR_07	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
19	AP	NCP @ meter - cust svs	NCP_MTR_06	0.000332	0.002979	0.215221	0.185886	0.048108	0.080691	0.038238
20	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	0.000000	0.000000	0.217273	0.187659	0.048567	0.081461	0.038603
21	AP	**BILLING DETERMINANTS**								
22	AP									
23	AP	Number of Customers								
24	AP	Delivered kWh @ Meter - annual (w/n net)								
25	AP	Delivered Kw @ Meter - annual								
26	AP									
27	AP	**ALLOCATION FACTORS PART B**								
28	AP									
29	AP	Delivery kWh @ meter	KWHMETER_04	0.000375	0.003369	0.180134	0.259443	0.076184	0.114404	0.016476
30	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	0.000000	0.000000	0.344551	0.000000	0.000000	0.000000	0.000000
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	0.000268	0.002411	0.128279	0.185634	0.053091	0.380163	0.000000
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	0.000433	0.003889	0.206955	0.299489	0.085653	0.000000	0.000000
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	0.000433	0.003889	0.206955	0.299489	0.085653	0.000000	0.000000
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	0.000474	0.004254	0.226342	0.327544	0.000000	0.000000	0.000000
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	0.000376	0.003372	0.179435	0.259664	0.076249	0.114501	0.016490
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	0.000376	0.003372	0.179435	0.259664	0.076249	0.114501	0.016490
37	AP									
38	AP									
39	AP	**ALLOCATION FACTORS PART C**								
40	AP									
41	AP	Draft EC Proforma	ECPRO_07	0.000000	0.000000	0.115608	0.000000	0.000000	0.000000	0.000000
42	AP	E587 Customer Installation Expenses Local	CUSINT_04	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
43	AP	E587 Customer Installation Expenses System	CUSINT_05	0.008929	0.008929	0.008929	0.008929	0.008929	0.000000	0.008929
44	AP	E369 minimum Service investment- access	SERVICESMIN_03	0.000000	0.000000	0.099089	0.001893	0.000454	0.000001	0.000000
45	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	0.000000	0.000000	0.194742	0.012740	0.000517	0.000586	0.000000
46	AP	Avg Customer Bills - local	CUSTAVG_04	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
47	AP	Avg Customer Bills - cust svs	CUSTAVG_06	0.000038	0.010042	0.122813	0.004059	0.000338	0.000083	0.000011
48	AP	E370 minimum meter investment - measurement	METERSMIN_07	0.000000	0.000000	0.345694	0.037510	0.009792	0.017432	0.003953
49	AP	E368 Line Transfomers - local	LNTRFRMR_04	0.000141	0.001350	0.140013	0.130578	0.000000	0.000000	0.000000
50	AP	Billing Function costs - cust svs	BILLING_06	0.000055	0.014481	0.177112	0.068465	0.005703	0.001401	0.000189

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
52	AP	Avg Customer Bills - measurement	CUSTAVG_07	1.000000	0.856580	0.002976	0.004972	0.000284	0.000004	0.000338	0.002114
53	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.832962	0.002894	0.004835	0.000263	0.000004	0.000314	0.000238
54	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.787219	0.002735	0.004569	0.000052	0.000001	0.000062	0.000000
55	AP										
56	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
58	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
59	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	1.000000	0.606307	0.002106	0.003519	0.000000	0.000000	0.000239	0.000000
60	AP										
61	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP										
63	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
65	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP										
70	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
71	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
72	AP										
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.501169	0.001741	0.002909	0.000477	0.000007	0.000198	0.000000
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP	Meter O&M - measurement	METERPLT_07	1.000000	0.834095	0.002687	0.004490	0.000709	0.000011	0.000305	0.000000
78	AP										
79	AP	E370 excess meter investment - dummy	METERSEXC_08	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
86	AP										
87	AP										
88	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
89	AP										
90	AP	**Plant Related**									
91	AP	Distribution Plant Total	DISTPLT	1.000000	0.390782	0.002399	0.018115	0.030801	0.000131	0.000300	0.036756
92	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.383425	0.002410	0.018629	0.031866	0.000135	0.000302	0.038046
93	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
94	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
95	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.394769	0.001979	0.004980	0.000008	0.000000	0.000312	0.004059
96	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.422000	0.002100	0.005309	0.000009	0.000000	0.000333	0.012149
97	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.417727	0.002058	0.005237	0.000008	0.000000	0.000329	0.004868
98	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.434187	0.002145	0.005486	0.000097	0.000000	0.000342	0.005997
99	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.434187	0.002145	0.005486	0.000097	0.000000	0.000342	0.005997
100	AP	Acct E369 Services	E369PLT	1.000000	0.001567	0.009866	0.267508	0.617005	0.002618	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
52	AP	Avg Customer Bills - measurement	CUSTAVG_07	0.000038	0.010096	0.118082	0.004081	0.000340	0.000084	0.000011
53	AP	Account Maint - cust svs	ACCTMAINT_06	0.000004	0.001134	0.124856	0.029368	0.002446	0.000601	0.000081
54	AP	Meter Reading Costs - measurement	MRCOST_07	0.000000	0.000000	0.192911	0.011253	0.000937	0.000230	0.000031
55	AP									
56	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Other Utility work by Cust Ops - local	UTILWORK_04	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
58	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
59	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	0.000000	0.000000	0.305010	0.051383	0.026243	0.005192	0.000000
60	AP									
61	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP									
63	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Direct - BPL - streetlighting	DIR_BPL_02	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
66	AP	Direct - HTS-HV - access	DIR_HTSHV_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
67	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
69	AP									
70	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
71	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
72	AP									
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	0.000000	0.000000	0.069088	0.383557	0.031948	0.007850	0.001056
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP	Meter O&M - measurement	METERPLT_07	0.000000	0.000000	0.134509	0.011842	0.003092	0.005503	0.002757
78	AP									
79	AP	E370 excess meter investment - dummy	METERSEXC_08	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
80	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
86	AP									
87	AP									
88	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
89	AP									
90	AP	**Plant Related**								
91	AP	Distribution Plant Total	DISTPLT	0.000200	0.014080	0.215092	0.225407	0.040997	0.024912	0.000028
92	AP	Distribution Plant x meters	DISTPLTXMTR	0.000207	0.014575	0.211637	0.231619	0.041635	0.025515	0.000000
93	AP	Acct E360 - Land & Land Rights	E360PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
94	AP	Acct E361 - Structures & Improvments	E361PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
95	AP	Acct E362 - Station Equipment	E362PLT	0.000219	0.001971	0.212629	0.240386	0.065859	0.072828	0.000000
96	AP	Acct E364 - Poles & Towers	E364PLT	0.000230	0.003828	0.227330	0.255580	0.037871	0.033260	0.000000
97	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	0.000221	0.004238	0.225073	0.251084	0.065347	0.023811	0.000000
98	AP	Acct E366 - UG Conduit	E366PLT	0.000231	0.002719	0.233945	0.261421	0.041149	0.012280	0.000000
99	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	0.000231	0.002719	0.233945	0.261421	0.041149	0.012280	0.000000
100	AP	Acct E369 Services	E369PLT	0.000000	0.000000	0.099089	0.001893	0.000454	0.000001	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
101	AP	Acct E370 Meters	METERPLT	1.000000	0.600343	0.002086	0.003485	0.000469	0.000007	0.000237	0.000000
102	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.600343	0.002086	0.003485	0.000469	0.000007	0.000237	0.000000
103	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.027834	0.000175	0.001352	0.002313	0.000010	0.000022	0.685169
104	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.310447	0.001000	0.003413	0.000000	0.000000	0.000222	0.000000
105	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.542086	0.002459	0.005140	0.000000	0.000000	0.000960	0.001680
106	AP										
107	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.393602	0.002407	0.017929	0.030364	0.000129	0.000314	0.036288
108	AP										
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	1.000000	0.383425	0.002410	0.018629	0.031866	0.000135	0.000302	0.038046
111	AP	Common Plant	COMPLT	1.000000	0.534815	0.002729	0.008543	0.008580	0.000037	0.000957	0.012725
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.417896	0.002483	0.016332	0.026564	0.000113	0.000452	0.032281
113	AP										
114	AP	Total Plant	TOTPLT	1.000000	0.393602	0.002407	0.017929	0.030364	0.000129	0.000314	0.036288
115	AP										
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.389409	0.002690	0.026411	0.050294	0.000214	0.000322	0.033270
117	AP	Total Net Plant	TOTPLTNET	1.000000	0.395157	0.002302	0.014783	0.022972	0.000098	0.000311	0.037407
118	AP										
119	AP										
120	AP	**Revenue Related**									
121	AP	Total Operating Revenue	TOTREV	1.000000	0.438158	0.002342	0.012709	0.018309	0.000079	0.000378	0.035406
122	AP										
123	AP										
124	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**									
125	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
126	AP										
127	AP	**Expense Related**									
128	AP	Distr Oper Exp	DISTEXPO	1.000000	0.495855	0.002140	0.005029	0.000274	0.000004	0.000319	0.011073
129	AP	Distr Maint Exp	DISTEXPM	1.000000	0.376172	0.001857	0.004702	0.000025	0.000000	0.000295	0.070603
130	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.789053	0.002665	0.004861	0.000176	0.000003	0.000310	0.002174
131	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.578754	0.002855	0.004868	0.000092	0.000001	0.001245	0.003574
132	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.589970	0.002845	0.004868	0.000096	0.000001	0.001195	0.003499
133	AP	Sales Expense	SALESEXP	1.000000	0.731132	0.002337	0.004988	0.000061	0.000001	0.000337	0.004998
134	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.453604	0.002327	0.008830	0.009059	0.000039	0.000527	0.035106
135	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.435904	0.002462	0.015638	0.024844	0.000106	0.000368	0.037069
136	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.578754	0.002855	0.004868	0.000092	0.000001	0.001245	0.003574
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.425084	0.002188	0.009402	0.010717	0.000046	0.000372	0.042936
138	AP										
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.394903	0.002410	0.017843	0.030160	0.000128	0.000322	0.036072
140	AP										
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.421866	0.002317	0.013930	0.021079	0.000090	0.000310	0.036265
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.507625	0.002308	0.004396	-0.000049	0.000001	0.000645	0.038076
143	AP										
144	AP	**Labor Expense Related**									
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.490268	0.001943	0.004039	0.000351	0.000005	0.000262	0.004906
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.365649	0.001909	0.004484	0.000436	0.000002	0.000307	0.123015
147	AP	Total Labor	LABOR	1.000000	0.506456	0.002309	0.004535	0.000263	0.000003	0.000642	0.038058
148	AP										
149	AP	**REVENUES AND BILLING DETERMINANTS**									
150	AP										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
101	AP	Acct E370 Meters	METERPLT	0.000000	0.000000	0.313507	0.048486	0.022808	0.007748	0.000825
102	AP	Acct E370 Meters x load profile meters	METERPLTXPR	0.000000	0.000000	0.313507	0.048486	0.022808	0.007748	0.000825
103	AP	Acct E373 - Streetlights	E373PLT	0.000015	0.246058	0.015363	0.016814	0.003022	0.001852	0.000000
104	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	0.000000	0.000000	0.168414	0.138526	0.035100	0.342878	0.000000
105	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	0.000080	0.000826	0.220885	0.180212	0.045672	0.000000	0.000000
106	AP									
107	AP	Acct E301-E303 Intangible Plt	INTANGPLT	0.000199	0.013980	0.214627	0.223924	0.040772	0.025154	0.000311
108	AP									
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	0.000207	0.014575	0.211637	0.231619	0.041635	0.025515	0.000000
111	AP	Common Plant	COMPLT	0.000163	0.008616	0.198883	0.145889	0.029460	0.035260	0.013344
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	0.000197	0.013218	0.208733	0.212098	0.038863	0.027733	0.003038
113	AP									
114	AP	Total Plant	TOTPLT	0.000199	0.013980	0.214627	0.223924	0.040772	0.025154	0.000311
115	AP									
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	0.000189	0.012913	0.212977	0.212537	0.037210	0.020883	0.000682
117	AP	Total Net Plant	TOTPLTNET	0.000203	0.014376	0.215238	0.228147	0.042094	0.026738	0.000174
118	AP									
119	AP									
120	AP	**Revenue Related**								
121	AP	Total Operating Revenue	TOTREV	0.000392	0.014413	0.207035	0.204113	0.039171	0.025923	0.001573
122	AP									
123	AP									
124	**AP**	**ALLOCATION FACTOR TABLE CONTINUED**								
125	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**								
126	AP									
127	AP	**Expense Related**								
128	AP	Distr Oper Exp	DISTEXPO	0.000173	0.003416	0.208229	0.204734	0.043702	0.024066	0.000988
129	AP	Distr Maint Exp	DISTEXPM	0.002960	0.033064	0.202595	0.224802	0.052519	0.030399	0.000006
130	AP	Cust Serv & Info Expense	CUSTS_I	0.000040	0.006487	0.164905	0.026440	0.002246	0.000572	0.000069
131	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	0.000153	0.006443	0.195888	0.119626	0.026308	0.040964	0.019228
132	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	0.000147	0.006445	0.194236	0.114656	0.025025	0.038810	0.018206
133	AP	Sales Expense	SALESEXP	0.000093	0.013559	0.224006	0.016539	0.001494	0.000419	0.000035
134	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	0.001306	0.017091	0.211161	0.182603	0.042620	0.031121	0.004607
135	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	0.000233	0.014778	0.213217	0.188509	0.040000	0.025617	0.001257
136	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	0.000153	0.006443	0.195888	0.119626	0.026308	0.040964	0.019228
137	AP	O&M + Capital Additions	EXPENDITURES	0.000547	0.017544	0.218765	0.203271	0.041772	0.025807	0.001550
138	AP									
139	AP	Depreciation Expense (total)	DEPREXP	0.000199	0.013939	0.214333	0.223280	0.040670	0.025286	0.000454
140	AP									
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	0.000223	0.013985	0.210371	0.214489	0.039869	0.025071	0.000136
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	0.000147	0.016468	0.176507	0.186603	0.032757	0.027091	0.007423
143	AP									
144	AP	**Labor Expense Related**								
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	0.000095	0.001629	0.142666	0.300960	0.037534	0.014454	0.000890
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	0.000212	0.045167	0.180720	0.205776	0.044473	0.027835	0.000016
147	AP	Total Labor	LABOR	0.000148	0.016442	0.176898	0.186985	0.032839	0.027071	0.007350
148	AP									
149	AP	**REVENUES AND BILLING DETERMINANTS**								
150	AP									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.439017	0.002347	0.012734	0.018345	0.000079	0.000377	0.035475
152	AP										
153	AP	Residential Service	REVRS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
154	AP	Residential Heating Service	REVRHS	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
155	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
156	AP	Water Heating Service	REVWH	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
157	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
158	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
159	AP	Body Police Lighting Service	REVBLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
160	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
161	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
162	AP										
163	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
165	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
166	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
167	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
168	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
169	AP										
170	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.439017	0.002347	0.012734	0.018345	0.000079	0.000377	0.035475
171	AP										
172	AP	**PRESENT REVENUES FROM SALES INPUT**									
173	AP										
174	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
175	AP	Sales of Electricity Revenues - Rates		1.000000	0.476039	0.003512	0.006199	0.000042	0.000000	0.000590	0.044679
176	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
177	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	0.000000	0.406337	0.006306	0.000000	0.000000
178	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.624242	0.002413	0.004379	0.000000	0.000000	0.000423	0.038400

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
151	AP	Base Rate Sales Revenue	SALESREV	0.000392	0.014384	0.206616	0.203701	0.039092	0.025870	0.001570
152	AP									
153	AP	Residential Service	REVRS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
154	AP	Residential Heating Service	REVRHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
155	AP	Residential Load Management Service	REVRLM	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
156	AP	Water Heating Service	REVWH	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
157	AP	Water Heating Storage Service	REVWHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
158	AP	Building Heating Service	REVHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
159	AP	Body Police Lighting Service	REVBLP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
160	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
161	AP	Private Street and Area Lighting Service	REVPAL	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
162	AP									
163	AP	General Power and Lighting Service	REVGLP	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Large Power and Lighting Service - Secondary	REVLPLS	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
165	AP	Large Power and Lighting Service - Primary	REVLPLP	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
166	AP	High Tension Service - Subtransmission	REVHTSS	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
167	AP	High Tension Service - High Voltage	REVHTSHV	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
168	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
169	AP									
170	AP	Total Rev Req @ desired ROR	REVREQ	0.000392	0.014384	0.206616	0.203701	0.039092	0.025870	0.001570
171	AP									
172	AP	**PRESENT REVENUES FROM SALES INPUT**								
173	AP									
174	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
175	AP	Sales of Electricity Revenues - Rates		0.000257	0.022169	0.211094	0.178457	0.031052	0.024050	0.001861
176	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
177	AP	Expense Reclassification Plus-local	ADJ_Plus_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.587357
178	AP	Expense Reclassification-local	ADJEXP_04	0.000059	0.016095	0.167800	0.111337	0.019957	0.014895	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
3	ADA										
4	ADA	**Net Write-Offs**									
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
20	ADA										
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0
22	ADA										
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA										
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0
26	ADA										
27	ADA										
28	ADA	**Rev to Customers w/Late Payment fees**									
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	701,978	0	0	0	0	0	701,978	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	26,795,398	0	0	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	384,902,021	0	0	0	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	0	0	0	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	0	0	0	0	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	0	0	0	0	0	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	0	0	0	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
44	ADA										
45	ADA	Total Late Payment Fees	REVLATEP	915,812,512	0	0	0	0	0	701,978	0
46	ADA	Total Late Payment Fees	REVLATEP	1.000000						0.000767	
47	ADA										
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**									
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS									
50	ADA										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**								
3	ADA									
4	ADA	**Net Write-Offs**								
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0
20	ADA									
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0
22	ADA									
23	ADA	Total Write-Offs	EXP_904	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
24	ADA									
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0
26	ADA									
27	ADA									
28	ADA	**Rev to Customers w/Late Payment fees**								
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	0	26,795,398	0	0	0	0	0
38	ADA	General Power and Lighting Service	REVGLP	0	0	384,902,021	0	0	0	0
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	379,469,998	0	0	0
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	72,824,417	0	0
41	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	48,193,633	0
42	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	2,925,067
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0
44	ADA									
45	ADA	Total Late Payment Fees	REVLATEP	0	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
46	ADA	Total Late Payment Fees	REVLATEP		0.029259	0.420285	0.414353	0.079519	0.052624	0.003194
47	ADA									
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**								
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS								
50	ADA									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
51	ADA	**AVAILABLE**									
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0
67	ADA										
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
51	ADA	**AVAILABLE**								
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0
67	ADA									
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RRW	**REVENUE REQUIREMENTS**									
2	RRW										
3	RRW	PRESENT RATES									
4	RRW	----------									
5	RRW	RATE BASE		9,635,540,505	4,158,694,615	22,302,297	127,655,917	188,021,228	805,896	3,044,800	344,429,795
6	RRW	NET OPER INC (PRESENT RATES)		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
10	RRW	REVENUE PRES RATES $/KWH		$0.0456	$0.0598	$0.0468	$0.1216	$58.4378	$20.5038	$0.0591	$0.2333
11	RRW	REVENUE REQUIRED - $/MO/CUST		$66.11	$34.07	$52.41	$170.24	$4,299.18	$1,182.19	$74.10	$1,115.23
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW										
14	RRW	CLAIMED RATE OF RETURN									
15	RRW	----------									
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		711,102,889	306,911,663	1,645,909	9,421,007	13,875,967	59,475	224,706	25,418,919
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,862,881,345	817,837,432	4,371,623	23,721,865	34,174,203	146,591	701,978	66,086,163
19	RRW	REVENUE DEFICIENCY SALES REV									
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	13,685,554,460	93,469,833	195,107,964	584,797	7,149	11,887,502	283,298,553
22	RRW	SALES REV REQUIRED $/KWH		$0.0456	$0.0598	$0.0468	$0.1216	$58.4378	$20.5038	$0.0591	$0.2333
23	RRW	REVENUE DEFICIENCY $/KWH									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	BPL-POF	PSAL	GLP	LPL-Secondary	LPL-Primary	HTS-Sub	HTS-High Voltage
				(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	RRW	**REVENUE REQUIREMENTS**								
2	RRW									
3	RRW	PRESENT RATES								
4	RRW	----------								
5	RRW	RATE BASE		2,214,624	133,309,963	2,012,626,362	2,022,581,857	377,880,185	239,503,489	2,469,479
6	RRW	NET OPER INC (PRESENT RATES)		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
10	RRW	REVENUE PRES RATES $/KWH		$0.0477	$0.1948	$0.0524	$0.0358	$0.0234	$0.0103	$0.0043
11	RRW	REVENUE REQUIRED - $/MO/CUST		$678.07	$94.70	$111.22	$3,317.36	$7,643.20	$20,586.77	$9,285.93
12	RRW	SALES REV REQUIRED $/KW		0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	RRW									
14	RRW	CLAIMED RATE OF RETURN								
15	RRW	----------								
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		163,439	9,838,275	148,531,825	149,266,541	27,887,558	17,675,357	182,248
18	RRW	SALES REVENUE REQ CLAIMED ROR		730,955	26,795,398	384,902,021	379,469,998	72,824,417	48,193,633	2,925,067
19	RRW	REVENUE DEFICIENCY SALES REV								
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED KWH SALES		15,313,401	137,520,699	7,352,369,374	10,589,422,620	3,109,525,559	4,669,504,753	672,466,899
22	RRW	SALES REV REQUIRED $/KWH		$0.0477	$0.1948	$0.0524	$0.0358	$0.0234	$0.0103	$0.0043
23	RRW	REVENUE DEFICIENCY $/KWH								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	S	**SUMMARY OF RESULTS**										
2	S	**DEVELOPMENT OF RETURN**										
3	S											
4	S	**RATE BASE**										
5	S	Plant in Service										
6	S	Production Plant E310-E346	CALCULATED	0	0	0	0	0	0	0	0	0
7	S	Transmission Plant E350-E359	CALCULATED	0	0	0	0	0	0	0	0	0
8	S	Distribution Plant										
9	S	Land & Structures E360-E361	CALCULATED	293,570,614	0	0	0	125,606,741	0	0	167,963,873	0
10	S	Station Equipment E362	CALCULATED	1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
11	S	Poles, Towers, and Fixtures E364	CALCULATED	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
12	S	OH Conductors and Devices E365	CALCULATED	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
13	S	UG Conductors E366	CALCULATED	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
14	S	UG Conduits and Devices E367	CALCULATED	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
15	S	Line Transformers E368	CALCULATED	1,591,690,631	0	0	756,053,050	0	0	0	0	835,637,581
16	S	Services E369	CALCULATED	535,269,333	0	535,269,333	0	0	0	0	0	0
17	S	Meters E370	CALCULATED	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
18	S	Street Lighting E373	CALCULATED	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
19	S	Asset Retirement Obligations E374	CALCULATED	96,512,525	932,488	0	30,447,221	13,034,833	0	0	19,151,745	32,946,239
20	S	Other Distribution and Unallocated Plant	CALCULATED	0	0	0	0	0	0	0	0	0
21	S	Total Distribution Plant	CALCULATED	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
22	S	General Plant E389-E399	CALCULATED	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
23	S	Common Plant C389-C399	CALCULATED	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
24	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589	9,156,764	10,452,822
25	S	Total Plant in Service	CALCULATED	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551
26	S											
27	S	Less: Reserve for Depreciation and Amorization	CALCULATED	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
28	S	Plus: Rate Base Additions										
29	S	Working Capital	CALCULATED	1,153,424,258	63,830,655	19,921,829	248,313,802	184,777,469	70,384,500	46,999,741	236,283,063	282,913,200
30	S	Plant Held for Future Use	CALCULATED	495,177	22,138	24,349	115,708	85,853	5,981	4,800	110,322	126,027
31	S	Capital Stimulus	CALCULATED	0	0	0	0	0	0	0	0	0
32	S	Other Rate Base Deductions		-27,893,945	-84,606	0	-6,602,796	-6,435,633	0	0	-7,856,977	-6,913,933
33	S	Other Rate Base Additions		2,015,996,645	61,220,311	62,612,913	315,548,459	238,042,456	4,631,514	683,436,361	306,146,618	344,358,014
34	S	Customer Advances	CALCULATED	-63,735,780	-2,837,691	-1,886,245	-12,528,067	-10,173,104	-4,124,283	-5,557,527	-13,057,373	-13,571,491
35	S	Unbilled Revenue	CALCULATED	0	0	0	0	0	0	0	0	0
36	S	Deferred Income Taxes and Credits	CALCULATED	-1,800,404,102	-79,935,371	-88,010,271	-417,605,067	-309,970,064	-33,113,358	-19,416,826	-398,307,698	-454,045,448
37	S											
38	S	Plus: Rate Base Deductions										
39	S	TOTAL RATE BASE		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982	2,097,950,132	2,258,824,013
40	S											
41	S	**SUMMARY OF RESULTS**										
42	S	**DEVELOPMENT OF RETURN**	CALCULATED									
43	S											
44	S	**RATE BASE**	CALCULATED	9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982	2,097,950,132	2,258,824,013
45	S											
46	S	**OPERATING REVENUES**										
47	S	Rate Revenues from Customers	CALCULATED	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
48	S	Other Operating Revenues	CALCULATED	25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219	5,362,318	5,458,939
49	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0	0
50	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0	0	0	0
51	S	TOTAL OPERATING REVENUES		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675	387,005,653	402,129,014
52	S											
53	S	**OPERATING EXPENSES**										
54	S	Operation and Maintenance Expense										
55	S	Production Expense	CALCULATED	0	0	0	0	0	0	0	0	0
56	S	Transmission Expense	CALCULATED	0	0	0	0	0	0	0	0	0
57	S	Distribution Expense	CALCULATED	178,009,259	13,223,105	74,179	23,979,432	38,515,543	0	18,936,951	48,738,710	34,541,340
58	S	Customer Accounts Expense	CALCULATED	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
59	S	Customer Service & Information Expense	CALCULATED	5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
60	S	Sales Expense	CALCULATED	40,922	0	0	40,922	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	S	Administrative and General Expense	CALCULATED	33,695,393	1,396,765	4,468,813	15,985,344	11,202,679	-18,612,894	-13,577,262	14,281,508	18,550,439
62	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325	63,020,218	53,091,779
63	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
64	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
65	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
66	S	Proforma Expense Adjustments	CALCULATED	83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614	10,094,506	10,186,317
67	S	State Income Taxes	CALCULATED	116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848	25,872,953	27,948,245
68	S	Federal Income Taxes	CALCULATED	224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531	49,884,176	53,585,017
69	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
70	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0	0
71	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0	0
72	S	TOTAL OPERATING EXPENSES		1,176,882,895	52,399,564	33,385,741	218,927,975	181,321,345	115,381,185	107,862,349	232,176,933	235,427,802
73	S											
74	S	**OPERATING INCOME (RETURN)**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
75	S	Plus Operating Income Adjustment	CALCULATED	0	0	0	0	0	0	0	0	0
76	S	TOTAL NET OPERATING INCOME		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
77	S											
78	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
79	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
80	S											
81	S	**EQUALIZED RETURN AT PROPOSED ROR**										
82	S											
83	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS**										
84	S											
85	S	**RATE BASE**	CALCULATED	9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982	2,097,950,132	2,258,824,013
86	S											
87	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
88	S											
89	S	**RETURN (RATE BASE * 7.40% ROR)**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
90	S											
91	S	**PLUS:**	CALCULATED									
92	S	**OPERATING EXPENSES**										
93	S	Total Operation and Maintenance Expense	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325	63,020,218	53,091,779
94	S	Depreciation Expense	CALCULATED	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
95	S	Amortization Expense	CALCULATED	21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
96	S	Taxes Other Than Income Taxes	CALCULATED	-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
97	S	Proforma Expense Adjustments	CALCULATED	83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614	10,094,506	10,186,317
98	S	Income Taxes	CALCULATED	340,725,434	15,350,240	11,268,169	74,523,415	58,750,263	1,285,576	22,257,379	75,757,130	81,533,262
99	S	Provision for Deferred Income Taxes	CALCULATED	144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
100	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0	0	0	0
101	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0	0	0	0
102	S	**TOTAL OPERATING EXPENSES**		1,176,882,895	52,399,564	33,385,741	218,927,975	181,321,345	115,381,185	107,862,349	232,176,933	235,427,802
103	S											
104	S	**EQUALS TOTAL COST OF SERVICE**		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675	387,005,653	402,129,014
105	S											
106	S	**LESS:**										
107	S	Other Operating Revenues	CALCULATED	25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219	5,362,318	5,458,939
108	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0	0	0	0
109	S	Plus: Provisions for Rate Refunds		0	0	0	0	0	0	0	0	0
110	S	**EQUALS:**										
111	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
112	S											
113	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0	0	0	0
114	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBP	**DEVELOPMENT OF RATE BASE**										
2	RBP											
3	RBP	**ELECTRIC PLANT IN SERVICE**										
4	RBP											
5	RBP	PRODUCTION PLANT										
6	RBP	E304-E346 - Production Plant	not_used	0	0	0	0	0	0	0	0	0
7	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
8	RBP	TOTAL PRODUCTION PLANT		0	0	0	0	0	0	0	0	0
9	RBP											
10	RBP	TRANSMISSION PLANT										
11	RBP	E350 Land & Land Rights	not_used	0	0	0	0	0	0	0	0	0
12	RBP	E352 Structures & Improvements	not_used	0	0	0	0	0	0	0	0	0
13	RBP	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0	0
14	RBP	E354/E355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0	0
15	RBP	E356-E359 Transmission Plant - Others	not_used	0	0	0	0	0	0	0	0	0
16	RBP	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0
17	RBP											
18	RBP	DISTRIBUTION PLANT										
19	RBP	E360-E361 Land & Structures										
20	RBP	E360 - Land and Land Rights										
21	RBP	- Headquarters related	E362PLT	14,080,608	0	0	0	6,024,510	0	0	8,056,097	0
22	RBP	- Direct - HTS-HV	E362PLT	0	0	0	0	0	0	0	0	0
23	RBP	- Direct - HEP	E362PLT	0	0	0	0	0	0	0	0	0
24	RBP	- Substation related	E362PLT	37,233,560	0	0	0	15,930,703	0	0	21,302,857	0
25	RBP	E361 - Structures and improvements										
26	RBP	- Headquarters related	E362PLT	124,204,880	0	0	0	53,142,139	0	0	71,062,742	0
27	RBP	- Substation related	E362PLT	118,051,566	0	0	0	50,509,390	0	0	67,542,177	0
28	RBP	Total Accounts E360-E361		293,570,614	0	0	0	125,606,741	0	0	167,963,873	0
29	RBP	E362 - Station Equipment										
30	RBP	Switching Stations - Energy Related - System		269,637,863	0	0	0	0	0	0	269,637,863	0
31	RBP	Switching Stations - Demand Related - System		68,805,545	0	0	0	68,805,545	0	0	0	0
32	RBP	H Class Substations - Energy Related - System		626,002,523	0	0	0	0	0	0	626,002,523	0
33	RBP	H Class Substations - Demand Related - System		600,972,238	0	0	0	600,972,238	0	0	0	0
34	RBP	4 kV Class Substations - Energy Related - System		0	0	0	0	0	0	0	0	0
35	RBP	4 kV Class Substations - Demand Related - System		0	0	0	0	0	0	0	0	0
36	RBP	Total Account E362		1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
37	RBP	E364 - Poles Towers & Fixtures										
38	RBP	Streetlight poles - direct to BPL	DIR_BPL_02	8,114,160	8,114,160	0	0	0	0	0	0	0
39	RBP	Streetlight poles - direct to PSAL	DIR_PSAL_02	1,812,825	1,812,825	0	0	0	0	0	0	0
40	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
41	RBP	Subtransmission lines - Energy Related - System		80,822,343	0	0	0	0	0	0	80,822,343	0
42	RBP	Subtransmission lines - Demand Related - System		20,624,052	0	0	0	20,624,052	0	0	0	0
43	RBP	Primary Lines - Energy Related - Local		123,061,406	0	0	0	0	0	0	0	123,061,406
44	RBP	Primary Lines - Energy Related - System		123,061,406	0	0	0	0	0	0	123,061,406	0
45	RBP	Primary Lines - Demand Related - Local		118,140,880	0	0	118,140,880	0	0	0	0	0
46	RBP	Primary Lines - Demand Related - System		118,140,880	0	0	0	118,140,880	0	0	0	0
47	RBP	Secondary Lines - Energy Related - Local		227,674,404	0	0	0	0	0	0	0	227,674,404
48	RBP	Secondary Lines - Demand Related - Local		205,991,127	0	0	205,991,127	0	0	0	0	0
49	RBP	Total Account E364		1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
50	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
51	RBD											
52	RBP	DISTRIBUTION PLANT CONTINUED										
53	RBP	E365 - OH Conductors and Devices										
54	RBP	Direct - BPL	DIR_BPL_02	2,226,625	2,226,625	0	0	0	0	0	0	0
55	RBP	Direct - PSAL	DIR_PSAL_02	6,436,532	6,436,532	0	0	0	0	0	0	0
56	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
57	RBP	Subtransmission lines - Energy Related - System		160,845,181	0	0	0	0	0	0	160,845,181	0
58	RBP	Subtransmission lines - Demand Related - System		41,044,089	0	0	0	41,044,089	0	0	0	0
59	RBP	Primary lines - Energy Related - Local		643,665,448	0	0	0	0	0	0	0	643,665,448
60	RBP	Primary lines - Energy Related - System		643,665,448	0	0	0	0	0	0	643,665,448	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	RBP	Primary lines - Demand Related - Local		617,928,923	0	0	617,928,923	0	0	0	0	0
62	RBP	Primary lines - Demand Related - System		617,928,923	0	0	0	617,928,923	0	0	0	0
63	RBP	Secondary lines -Energy Related - Local		64,282,796	0	0	0	0	0	0	0	64,282,796
64	RBP	Secondary lines -Demand Related - Local		58,160,625	0	0	58,160,625	0	0	0	0	0
65	RBP	Other	DISTPLT	0	0	0	0	0	0	0	0	0
66	RBP	Total Account E365		2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
67	RBP											
68	RBP	E366 - Underground Conduit										
69	RBP	Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
70	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
71	RBP	Underground Conduits	E367PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
72	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
73	RBP	Total Account E366		512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
74	RBP											
75	RBP	E367 - Underground Conductors & Devices										
76	RBP	Direct - BPL	DIR_BPL_02	2,325,498	2,325,498	0	0	0	0	0	0	0
77	RBP	Direct - PSAL	DIR_PSAL_02	868,520	868,520	0	0	0	0	0	0	0
78	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	3,979,461	186,813	205,472	929,335	724,480	0	0	930,962	1,002,399
79	RBP	Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
80	RBP	367.1 - Conventional UG										
81	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	40,943,727	0	0	0	0	0	0	40,943,727	0
82	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	10,447,922	0	0	0	10,447,922	0	0	0	0
83	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	90,324,112	0	0	0	0	0	0	0	90,324,112
84	RBP	Primary lines - Energy Related - System	KWH_PRI_09	90,324,112	0	0	0	0	0	0	90,324,112	0
85	RBP	Primary lines - Demand Related - Local	CP_PRI_04	86,712,563	0	0	86,712,563	0	0	0	0	0
86	RBP	Primary lines - Demand Related - System	CP_PRI_05	86,712,563	0	0	0	86,712,563	0	0	0	0
87	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	283,098,081	0	0	0	0	0	0	0	283,098,081
88	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	256,136,359	0	0	256,136,359	0	0	0	0	0
89	RBP	367.2 - BUD										
90	RBP	Subtransmission lines - Energy Related - System	KWH_SUBT_09	381,867	0	0	0	0	0	0	381,867	0
91	RBP	Subtransmission lines - Demand Related - System	CP_SUBT_05	97,444	0	0	0	97,444	0	0	0	0
92	RBP	Primary lines - Energy Related - Local	KWH_PRI_10	114,385,571	0	0	0	0	0	0	0	114,385,571
93	RBP	Primary lines - Energy Related - System	KWH_PRI_09	114,385,571	0	0	0	0	0	0	114,385,571	0
94	RBP	Primary lines - Demand Related - Local	CP_PRI_04	109,811,942	0	0	109,811,942	0	0	0	0	0
95	RBP	Primary lines - Demand Related - System	CP_PRI_05	109,811,942	0	0	0	109,811,942	0	0	0	0
96	RBP	Secondary lines -Energy Related - Local	KWH_SEC_10	15,979,016	0	0	0	0	0	0	0	15,979,016
97	RBP	Secondary lines -Demand Related - Local	CP_SEC_04	14,457,205	0	0	14,457,205	0	0	0	0	0
98	RBP	Other	E367PLT	0	0	0	0	0	0	0	0	0
99	RBP	Total Account E367		1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
100	RBP											
101	RBP	E368 - Line Transformers										
102	RBP	Line Transformers - Energy Related - Local	KWH_SEC_10	835,637,581	0	0	0	0	0	0	0	835,637,581
103	RBP	Line Transformers - Demand Related - Local	CP_SEC_04	756,053,050	0	0	756,053,050	0	0	0	0	0
104	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
105	RBP	Total Account E368		1,591,690,631	0	0	756,053,050	0	0	0	0	835,637,581
106	RBP	E369 - Services										
107	RBP	Basic portion (minimum size)	SERVICESMIN_03	535,269,333	0	535,269,333	0	0	0	0	0	0
108	RBP	E369 - Excess portion	SERVICESEXC_04	0	0	0	0	0	0	0	0	0
109	RBP	Total Account E369		535,269,333	0	535,269,333	0	0	0	0	0	0
110	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
111	RBP											
112	RBP	E370 - Meters										
113	RBP	Load profiling meters	KWHMETERX_04	0	0	0	0	0	0	0	0	0
114	RBP	Customer Component	METERSMIN_07	76,316,914	0	0	0	0	0	76,316,914	0	0
115	RBP	Excess portion - Demand (Commercial Customers)	METERSEXC_04	122,177,671	0	0	122,177,671	0	0	0	0	0
116	RBP	Excess portion - Demand (Residential Customers)	METERSEXC_10	166,926,857	0	0	0	0	0	0	0	166,926,857
117	RBP	Total Account E370		365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
118	RBP											
119	RBP	E373 - Street Lighting & Signal Systems										
120	RBP	BPL luminaires & poles	DIR_BPL_02	340,539,607	340,539,607	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	RBP	PSAL luminaires & poles	DIR_PSAL_02	122,261,652	122,261,652	0	0	0	0	0	0	0
122	RBP	UG BPL Poles in UG areas	DISTPLTXMTR	36,225,893	1,700,598	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
123	RBP	Total Account E373		499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
124	RBP											
125	RBP	E374 - Asset Retirement Obligations	E364PLT	96,512,525	932,488	0	30,447,221	13,034,833	0	0	19,151,745	32,946,239
126	RBP											
127	RBP	Other Distribution and Unallocated Plant										
128	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
129	RBP	Total Other Plant and Unallocated Plant		0	0	0	0	0	0	0	0	0
130	RBP											
131	RBP	TOTAL DISTRIBUTION PLANT		10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
132	RBP											
133	RBP	GENERAL AND COMMON PLANT										
134	RBP	E390-E398 GENERAL PLANT										
135	RBP	Meter Related	METERPLT	0	0	0	0	0	0	0	0	0
136	RBP	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0	0
137	RBP	Substation Related	E362PLT	0	0	0	0	0	0	0	0	0
138	RBP	Distribution Delivery	DISTPLTXMTR	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
139	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
140	RBP	Unassigned	GENPLT	0	0	0	0	0	0	0	0	0
141	RBP	Total Accounts E390-E398		429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
142	RBP											
143	RBP	C389-C399 COMMON PLANT										
144	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
145	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
146	RBP	Customer Related - Measurement	MRCOST_07	0	0	0	0	0	0	0	0	0
147	RBP	Demand Related - Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0	0
148	RBP	Customer Service Related	CUSTSVSX	92,605,476	0	0	3,365,638	0	71,953,745	17,286,093	0	0
149	RBP	Distribution Delivery Related	DISTPLTXMTR	33,738,596	1,583,834	1,742,030	7,879,075	6,142,271			7,892,866	8,498,520
150	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
151	RBP	Unassigned	COMPLT	309,972	3,886	4,274	27,588	15,069	176,531	42,410	19,364	20,850
152	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
153	RBP	Total Accounts C389-C399		126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
154	RBP											
155	RBP	TOTAL GENERAL AND COMMON PLANT		556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503	108,410,004	116,728,774
156	RBP											
157	RBP	**ELECTRIC PLANT IN SERVICE CONTINUED**										
158	RBP											
159	RBP	INTANGIBLE PLANT - E301-E303										
160	RBP	Customer Service Related	TOTPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
161	RBP	Not Used	not_used	0	0	0	0	0	0	0	0	0
162	RBP	TOTAL INTANGIBLE PLANT		40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
163	RBP											
164	RBP	C303 - INTANGIBLE PLANT										
165	RBP	- Customer Related - Measurement	MRCOST_07	606,400	0	0	0	0	0	606,400	0	0
166	RBP	- Demand Related - Measurement	NCP_MTR_07	606,400	0	0	0	0	0	606,400	0	0
167	RBP	Customer Service Related	CUSTSVSX	84,635,615	0	0	3,075,982	0	65,761,224	15,798,408	0	0
168	RBP	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0	0
169	RBP	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0	0
170	RBP	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0	0
171	RBP	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307			114,761	123,567
172	RBP	TOTAL ACCOUNTS C303-C390.4,E399		86,338,967	23,029	25,329	3,190,542	89,307	65,761,224	17,011,208	114,761	123,567
173	RBP											
174	RBP	TOTAL INTANGIBLE PLANT		126,923,895	1,837,456	2,020,984	12,674,013	7,125,844	66,251,423	17,404,589	9,156,764	10,452,822
175	RBP											
176	RBP	**TOTAL ELECTRIC PLANT IN SERVICE**		11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**										
2	RBD											
3	RBD	E301-E303 - INTANGILE PLANT - RESERVE										
4	RBD	Customer Service Related - Reserve	CUSTSVSX	15,757,979	0	0	572,705	0	12,243,829	2,941,445	0	0
5	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
6	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
7	RBD	Total Accounts E301-E303 Reserve		15,757,979	0	0	572,705	0	12,243,829	2,941,445	0	0
8	RBD											
9	RBD	E304-E346 - PRODUCTION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0	0
10	RBD	E350-E359 - TRANSMISSION PLANT - RESERVE	not_used	0	0	0	0	0	0	0	0	0
11	RBD											
12	RBD	DISTRIBUTION PLANT RESERVE										
13	RBD	E360-E361 Land & Structures - Reserve										
14	RBD	E360 - Land and Land Rights										
15	RBD	- Headquarters Related	DISTPLT	0	0	0	0	0	0	0	0	0
16	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
17	RBD	- Direct - HEP	DIR_HEP_03	0	0	0	0	0	0	0	0	0
18	RBD	- Substation Related	E362PLT	667,893	0	0	0	285,764	0	0	382,129	0
19	RBD	E361 - Structures and improvements										
20	RBD	- Headquarters Related	DISTPLT	40,449,681	1,834,475	2,017,706	9,584,647	7,114,286	0	286,527	9,141,912	10,470,128
21	RBD	- Substation Related	E362PLT	36,319,499	0	0	0	15,539,614	0	0	20,779,885	0
22	RBD	Total Accounts E360-E361		77,437,073	1,834,475	2,017,706	9,584,647	22,939,663	0	286,527	30,303,927	10,470,128
23	RBD	E362 Station Equipment - Rsrv	E362PLT	279,293,104	0	0	0	119,497,984	0	0	159,795,119	0
24	RBD	E364 Poles Towers and Fixtures Rsrv										
25	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
26	RBD	- All Other	E364PLT	200,061,625	1,932,962	0	63,114,300	27,020,014	0	0	39,699,813	68,294,536
27	RBD	E365 OH Conductors and Devices - Rsrv										
28	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
29	RBD	- All Other	E365PLT	609,997,837	1,850,198	0	144,393,035	140,737,441	0	0	171,820,038	151,197,125
30	RBD	E366 UG Conduit - Rsrv										
31	RBD	- Direct - HTS-HV	DIR_HTSHV_03	0	0	0	0	0	0	0	0	0
32	RBD	- All Other	E366PLT	258,299,502	610,171	37,084	84,473,035	37,502,653	0	0	44,572,382	91,104,178
33	RBD	E367 UG Conductors and Devices - Rsrv										
34	RBD	- Direct - HTS-HV	DIR_HEP_03	0	0	0	0	0	0	0	0	0
35	RBD	- All Other	E367PLT	512,800,757	1,211,370	73,622	167,703,909	74,453,837	0	0	88,489,335	180,868,685
36	RBD	E368 Line Transformers - Rsrv Energy Related - Local	KWH_SEC_10	198,944,531	0	0	0	0	0	0	0	198,944,531
37	RBD	E368 Line Transformers - Rsrv Demand Related - Local	CP_SEC_04	179,997,433	0	0	179,997,433	0	0	0	0	0
38	RBD	E369 Services - Rsrv										
39	RBD	Services	E369PLT	240,814,772	0	240,814,772	0	0	0	0	0	0
40	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
41	RBD	Total Accounts E369 Rsrv		240,814,772	0	240,814,772	0	0	0	0	0	0
42	RBD	E370 Meters - Rsrv										
43	RBD	Load profile meters	KWHMETERX_04	0	0	0	0	0	0	0	0	0
44	RBD	All other Meters	METERPLTXPR	136,921,647	0	0	45,779,382	0	0	28,595,579	0	62,546,686
45	RBD	Total Account E370 Rsrv		136,921,647	0	0	45,779,382	0	0	28,595,579	0	62,546,686
46	RBD	E373 Street Lighting - Rsrv										
47	RBD	Streetlight fixtures	E373PLT	118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0	2,019,891	2,174,886
48	RBD	Not used	not_used	0	0	0	0	0	0	0	0	0
49	RBD	Total Account E373 Rsrv		118,939,285	110,710,447	445,809	2,016,362	1,571,890	0	0	2,019,891	2,174,886
50	RBD											
51	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**										
52	RBD	Other Plant Unallocated - Reserve										
53	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
54	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
55	RBD	Total Other Plant Unallocated - Reserve		0	0	0	0	0	0	0	0	0
56	RBD											
57	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
58	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
59	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
60	RBD											

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,813,507,566	118,149,623	243,388,992	697,062,102	423,723,484		28,882,106	536,700,505	765,600,754
62	RBD											
63	RBD	GENERAL AND COMMON PLANT RESERVE										
64	RBD	E390-E398 GENERAL PLANT - RESERVE										
65	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
66	RBD	Customer Service Related	CUSTSVSX	0	0	0	0	0	0	0	0	0
67	RBD	Substation Related	E362PLT	0	0	0	0	0	0	0	0	0
68	RBD	Distribution Delivery Related	DISTPLTXMTR	156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0	36,594,278	39,402,316
69	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
70	RBD	Unassigned	GENPLT	0	0	0	0	0	0	0	0	0
71	RBD	Total Accounts E390-E398 Reserve		156,424,740	7,343,245	8,076,701	36,530,334	28,477,866	0	0	36,594,278	39,402,316
72	RBD											
73	RBD	C389-C399 COMMON PLANT RESERVE										
74	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
75	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0	0	0	0
76	RBD	Meter Reading Related - Customer Related Measuremen	MRCOST_07	0	0	0	0	0	0	0	0	0
77	RBD	Meter Reading Related - Demand Related Measurement	NCP_MTR_07	0	0	0	0	0	0	0	0	0
78	RBD	Customer Service Related	CUSTSVSX	46,782,308	0	0	1,700,248	0	36,349,495	8,732,565	0	0
79	RBD	Distribution Delivery Related	DISTPLTXMTR	19,175,874	900,197	990,111	4,478,199	3,491,059	0	0	4,486,038	4,830,271
80	RBD	Sales and Service Dept. Related	UTILWORK_04	0	0	0	0	0	0	0	0	0
81	RBD	Unassigned	COMPLT	0	0	0	0	0	0	0	0	0
82	RBD	Not Used	not_used	0	0	0	0	0	0	0	0	0
83	RBD	Total Accounts C389-C399 Reserve		65,958,182	900,197	990,111	6,178,447	3,491,059	36,349,495	8,732,565	4,486,038	4,830,271
84	RBD											
85	RBD	C303 - INTANGIBLE PLANT										
86	RBD	- Customer Related - Measurement	MRCOST_07	311,743	0	0	0	0	0	311,743	0	0
87	RBD	- Demand Related - Measurement	NCP_MTR_07	311,743	0	0	0	0	0	311,743	0	0
88	RBD	Customer Service Related	CUSTSVSX	46,570,192	0	0	1,692,539	0	36,184,682	8,692,971	0	0
89	RBD	Distribution Related	INTANGPLT	0	0	0	0	0	0	0	0	0
90	RBD	C390.4 / C111.000 Capital Lease	TOTPLT	0	0	0	0	0	0	0	0	0
91	RBD	E399 Oth Tangible Plant	GENPLT	0	0	0	0	0	0	0	0	0
92	RBD	E399.1 Asset Retirement Obligations	GENPLT	490,552	23,029	25,329	114,560	89,307	0	0	114,761	123,567
93	RBD	Total Accounts C303-C390.4,E399		47,684,230	23,029	25,329	1,807,099	89,307	36,184,682	9,316,457	114,761	123,567
94	RBD											
95	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
96	RBD	**NET ELECTRIC PLANT IN SERVICE**		8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433	1,974,632,177	2,105,957,644

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**										
2	RBO											
3	RBO	**PLUS: ADDITIONS TO RATE BASE**										
4	RBO											
5	RBO	Working Capital										
6	RBO	Cash (lead/lag)	EXPENDITURES	925,712,100	51,229,033	15,988,807	199,291,015	148,298,198	56,489,000	37,720,924	189,635,417	227,059,705
7	RBO	Materials and Supplies	EXPENDITURES	227,211,892	12,573,937	3,924,381	48,915,088	36,399,129	13,864,972	9,258,432	46,545,164	55,730,788
8	RBO	Prepayments	EXPENDITURES	500,266	27,685	8,641	107,699	80,142	30,527	20,385	102,481	122,706
9	RBO	Working Funds	EXPENDITURES	0	0	0	0	0	0	0	0	0
10	RBO	Total Working Capital		1,153,424,258	63,830,655	19,921,829	248,313,802	184,777,469	70,384,500	46,999,741	236,283,063	282,913,200
11	RBO	Net Plant Adds - Distribution	DISTPLT	1,016,196,832	46,086,595	50,689,805	240,790,218	178,728,596	0	7,198,277	229,667,630	263,035,709
12	RBO	Capital Lease Plant & Reserve Deduction	TOTPLT	495,177	22,138	24,349	115,708	85,853	5,981	4,800	110,322	126,027
13	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0	0	0	0
14	RBO	Net Plant Adds - General & Other	TOTPLTNET	286,198,206	13,210,949	10,645,918	66,261,863	52,413,918	1,835,596	2,094,949	67,618,963	72,116,050
15	RBO	TOTAL ADDITIONS TO RATE BASE		3,169,916,080	125,073,103	82,559,090	563,977,968	422,905,778	75,021,994	730,440,902	542,540,003	627,397,242
16	RBO											
17	RBO											
18	RBO	**PLUS: DEDUCTIONS TO RATE BASE**										
19	RBO											
20	RBO	Customer Advances for Construction	REVREQ	-63,735,780	-2,837,691	-1,886,245	-12,528,067	-10,173,104	-4,124,283	-5,557,527	-13,057,373	-13,571,491
21	RBO	Unbilled Revenue	TOTREV	0	0	0	0	0	0	0	0	0
22	RBO	Deferred Income Taxes and Credits										
23	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0	0	0	0
24	RBO	Liberalized Depreciation	TOTPLT	-2,247,763	-100,491	-110,528	-525,234	-389,713	-27,149	-21,787	-500,784	-572,077
25	RBO	Cost of Removal	TOTPLT	15,629,066	698,727	768,517	3,652,040	2,709,737	188,774	151,489	3,482,033	3,977,748
26	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0	0	0	0
27	RBO	Computer Software	INTANGPLT	0	0	0	0	0	0	0	0	0
28	RBO	Capitalized Interest	TOTPLTNET	312,066	14,405	11,608	72,251	57,151	2,002	2,284	73,731	78,634
29	RBO	NJ Corporate Business Tax	TOTPLTNET	6,378,736	294,443	237,274	1,476,833	1,168,192	40,911	46,692	1,507,080	1,607,310
30	RBO	Defrd Tax & Consolidated Tax Adjustment	DEPREXP	(1,820,476,207)	(80,842,456)	(88,917,143)	(422,280,957)	(313,515,432)	(33,317,895)	(19,595,504)	(402,869,758)	(459,137,063)
31	RBO	Total Deferred Income Taxes and Credits		-1,800,404,102	-79,935,371	-88,010,271	-417,605,067	-309,970,064	-33,113,358	-19,416,826	-398,307,698	-454,045,448
32	RBO											
33	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,892,033,827)	(82,857,667)	(89,896,516)	(436,735,931)	(326,578,801)	(37,237,641)	(24,974,353)	(419,222,047)	(474,530,872)
34	RBO											
35	RBO											
36	RBO	**TOTAL RATE BASE**		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982	2,097,950,132	2,258,824,013
37	RBO	IAP Adjustment	E365PLT	-27,893,945	-84,606	0	-6,602,796	-6,435,633	0	0	-7,856,977	-6,913,933
38	RBO	CEF-EV Adjustment	TOTREV	43,223,143	1,922,767	1,277,190	8,496,378	6,899,941	2,795,918	3,764,670	8,860,025	9,206,256
39	RBO	CEF-EC Adjustment	ECPRO_07	670,378,464	0	0	0	0	0	670,378,464	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	REV	**OPERATING REVENUES**										
2	REV											
3	REV	**SALES REVENUES**										
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
5	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
6	REV	Not Used	not_used									
7	REV	TOTAL SALES OF ELECTRICITY		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
8	REV											
9	REV	**OTHER OPERATING REVENUES**										
10	REV	450-Forfeited Discounts	REVLATEP	3,653,078	91,595	22,223	732,158	623,459	192,724	135,838	965,146	889,935
11	REV	456-Other Electric Revenues	TOTREV	21,451,361	954,257	633,861	4,216,696	3,424,395	1,387,596	1,868,381	4,397,172	4,569,004
12	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
13	REV	Not Used	not_used									
14	REV	TOTAL OTHER OPERATING REV		25,104,439	1,045,852	656,084	4,948,854	4,047,855	1,580,320	2,004,219	5,362,318	5,458,939
15	REV											
16	REV	**OTHER REVENUE SOURCES**										
17	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0	0	0	0
19	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0	0	0	0
20	REV											
21	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0	0	0	0
22	REV											
23	REV	**TOTAL OPERATING REVENUES**		1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675	387,005,653	402,129,014

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	E	**OPERATION & MAINTENANCE EXPENSE**										
2	E	PRODUCTION EXPENSE										
3	E	E500-E557 Production Expenses										
4	E	Not Used	not_used	0	0	0	0	0	0	0	0	0
5	E	Total Production Expense		0	0	0	0	0	0	0	0	0
6	E	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0	0
7	E											
8	E	TRANSMISSION EXPENSES										
9	E	E560-E573 Transmission Exp	not_used	0	0	0	0	0	0	0	0	0
10	E	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0	0
11	E											
12	E	DISTRIBUTION EXPENSES										
13	E	Operation										
14	E	E580 Operation Supervision & Eng'g	DISTEXPO	0	0	0	0	0	0	0	0	0
15	E	E581 Load Dispatching	CP_SUBT_05	0	0	0	0	0	0	0	0	0
16	E	E582 Station Expenses	E362PLT	2,539,578	0	0	0	1,086,581	0	0	1,452,997	0
17	E	E583 OH Line Expenses	E365PLT	4,195,894	12,727	0	993,213	968,068	0	0	1,181,871	1,040,015
18	E	E584 Underground Line Expenses	E367PLT	6,199,909	14,646	890	2,027,589	900,168	0	0	1,069,862	2,186,755
19	E	E585 Street Lighting and System Expenses	E373PLT	173,106	161,130	649	2,935	2,288			2,940	3,165
20	E	E586 Meter Expenses										
21	E	- Basic portion (minimum size)	METERPLT_07	5,865,310	0	0	0	0	0	5,865,310	0	0
22	E	- Excess portion	not_used	0	0	0	0	0	0	0	0	0
23	E	E587 Customer Installations Expenses	MTROMMIN_07	0	0	0	0	0	0	0	0	0
24	E	-E587 Customer Installation Expenses - System	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0	0	0
25	E	-E587 Customer Installation Expenses - Local	CUSTAVG_04	-1,314,125	0	0	-1,314,125	0	0	0	0	0
26	E	E588 Miscellaneous Distribution Expenses	DISTEXPO	35,897,260	413,979	3,380	868,547	6,494,243	0	12,881,096	8,142,596	7,093,420
27	E	E589 Rents	DISTPLT	1,330,133	60,324	66,350	315,178	233,944	0	9,422	300,619	344,296
28	E	Total Distribution Operation		53,572,940	662,805	71,268	1,579,212	9,685,291	0	18,755,828	12,150,885	10,667,651
29	E	Maintenance										
30	E	E590 Maint. Supervision & Eng'g	DISTEXPM	0	0	0	0	0	0	0	0	0
31	E	E591 Maint of Structures	E360PLT	12,325,542	0	0	0	5,273,590	0	0	7,051,952	0
32	E	E592 Maint of Station Equipment	E362PLT	17,215,431	0	0	0	7,365,772	0	0	9,849,659	0
33	E	E593 Maint of Overhead Lines										
34	E	- Direct assigned - BPL poles	DIR_BPL_02	40,988	40,988	0	0	0	0	0	0	0
35	E	- Direct assigned - PSAL poles	DIR_PSAL_02	118,210	118,210	0	0	0	0	0	0	0
36	E	- all other O&M	E365PLT	56,305,216	170,781	0	13,328,049	12,990,623	0	0	15,859,670	13,956,093
37	E	E594.0 Maint of Underground Lines	E367PLT	20,076,605	47,426	2,882	6,565,757	2,914,934	0	0	3,464,436	7,081,170
38	E	Not used	not_used	0	0	0	0	0	0	0	0	0
39	E	E595 Maint of Line Transformers - Energy Related Local	KWH_SEC_10	2,207,903	0	0	0	0	0	0	0	2,207,903
40	E	E595 Maint of Line Transformers - Demand Related Local	CP_SEC_04	1,997,626	0	0	1,997,626	0	0	0	0	0
41	E	E596 Maint of Street Lighting & Signal Systems										
42	E	- BPL luminaires	DIR_BPL_02	8,123,869	8,123,869	0	0	0	0	0	0	0
43	E	- BPL-POF luminaires	DIR_BPLPOF_02	340,052	340,052	0	0	0	0	0	0	0
44	E	- PSAL luminaires	DIR_PSAL_02	3,594,664	3,594,664	0	0	0	0	0	0	0
45	E	E597 Maint of Meters										
46	E	- Load profiling meters O&M	KWHMETERX_04	0	0	0	0	0	0	0	0	0
47	E	- Basic portion (minimum size)	METERPLTXPR	858,670	0	0	287,094	0	0	179,330	0	392,246
48	E	- Excess portion	METERSEXC_04	0	0	0	0	0	0	0	0	0
49	E	E598 Other Dist Maint Exp	DISTEXPM	1,231,542	124,309	29	221,694	285,332	0	1,793	362,108	236,277
50	E	Total Distribution Maintenance		124,436,319	12,560,300	2,911	22,400,220	28,830,251	0	181,123	36,587,825	23,873,689
51	E											
52	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951	48,738,710	34,541,340
53	E											
54	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
55	E											
56	E	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		178,009,259	13,223,105	74,179	23,979,432	38,515,543		18,936,951	48,738,710	34,541,340
57	E											
58	E											
59	E	CUSTOMER ACCOUNTS EXPENSES										
60	E	E901 Supervision	CUSTACCTS	0	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	E	E902 Meter Reading										
62	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0	0
63	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0	0
64	E	- Meter Reading - Customer Related Measurement	MRCOST_07	9,323,486	0	0	0	0	0	9,323,486	0	0
65	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	9,323,486	0	0	0	0	0	9,323,486	0	0
66	E	- Billing - Customer Related - Cust Svs	BILLING_06	0	0	0	0	0	0	0	0	0
67	E	- Billing - Customer Related - Cust Svs	NCPXSL_MTR_07	0	0	0	0	0	0	0	0	0
68	E	- Remaining - Customer Related - Measurement	MRCOST_07	-283,695	0	0	0	0	0	-283,695	0	0
69	E	- Remaining - Demand Related - Measurement	NCPXSL_MTR_07	-283,695	0	0	0	0	0	-283,695	0	0
70	E	E903 Customer Records and Collection										
71	E	- SONP/RNP - Customer Related - Local D	CUSTAVG_04	275,332	0	0	275,332	0	0	0	0	0
72	E	- SONP/RNP - Demand Related - Local D	NCP_MTR_04	275,332	0	0	275,332	0	0	0	0	0
73	E	- Meter O&M - Customer Related - Cust Svs	METERPLT	0	0	0	0	0	0	0	0	0
74	E	- Meter O&M - Demand Related - Cust Svs	NCP_MTR_06	0	0	0	0	0	0	0	0	0
75	E	- Meter Reading - Customer Related Measurement	MRCOST_07	266,527	0	0	0	0	0	266,527	0	0
76	E	- Meter Reading - Demand Related Measurement	NCPXSL_MTR_07	266,527	0	0	0	0	0	266,527	0	0
77	E	- Billing - Customer Related - Cust Svs	BILLING_06	40,496	0	0	0	0	40,496	0	0	0
78	E	- Billing - Customer Related - Cust Svs	NCP_MTR_06	40,496	0	0	0	0	40,496	0	0	0
79	E	- Acct Maint Related - Customer Related - Cust Svs	ACCTMAINT_06	3,872,512	0	0	0	0	3,872,512	0	0	0
80	E	- Acct Maint Related - Demand Related - Cust Svs	NCP_MTR_06	3,872,512	0	0	0	0	3,872,512	0	0	0
81	E	- Utility Work Related -Customer related - Local D	UTILWORK_04	531,469	0	0	531,469	0	0	0	0	0
82	E	- Utility Work Related -Demand Related - Local D	NCP_MTR_04	531,469	0	0	531,469	0	0	0	0	0
83	E	- Remaining - Customer Related - Cust Svs	BILLING_06	33,170,904	0	0	0	0	33,170,904	0	0	0
84	E	- Remaining - Demand Related - Cust Svs	NCP_MTR_06	33,170,904	0	0	0	0	33,170,904	0	0	0
85	E	Not used	not_used	0	0	0	0	0	0	0	0	0
86	E	E904 Uncollectible Accounts	not_used	0	0	0	0	0	0	0	0	0
87	E	E905 Misc Customer Accounts	CUSTACCTS									
88	E	TOTAL CUSTOMER ACCTS EXPENSE		94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
89	E											
90	E											
91	E	CUSTOMER SERVICE & INFO EXPENSES										
92	E	E907 & 908 - Cust Svs & Info										
93	E	- SONP/RNP	CUSTAVG_06	0	0	0	0	0	0	0	0	0
94	E	- Acct Maint related	ACCTMAINT_06	2,356,739	0	0	0	0	2,356,739	0	0	0
95	E	- Utility work related	UTILWORK_04	847,228	0	0	847,228	0	0	0	0	0
96	E	- Sales	SALES_06	0	0	0	0	0	0	0	0	0
97	E	- Billing	BILLING_06	41,297	0	0	0	0	41,297	0	0	0
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0	0	0	0
99	E	E909 Info & Instr Advertising	CUSTNUMX_04	0	0	0	0	0	0	0	0	0
100	E	E910 - Misc Cust Svs & Info										
101	E	- Utility work related	UTILWORK_04	1,163,089	0	0	1,163,089	0	0	0	0	0
102	E	- Acct Maint related	ACCTMAINT_06	689,620	0	0	0	0	689,620	0	0	0
103	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
104	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
105	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
106	E	- Not used	not_used	0	0	0	0	0	0	0	0	0
107	E	- Remaining	BILLING_06	220,028					220,028			
108	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
109	E											
110	E	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
111	E											
112	E	SALES EXPENSES										
113	E	E911-E916 Sales Expenses										
114	E	- Sales	SALES_06	0	0	0	0	0	0	0	0	0
115	E	- Billing related	BILLING_06	0	0	0	0	0	0	0	0	0
116	E	- Acct Maint related	ACCTMAINT_06	0	0	0	0	0	0	0	0	0
117	E	- Utility work related	UTILWORK_04	40,922	0	0	40,922	0	0	0	0	0
118	E	- Remaining	UTILWORK_04	0	0	0	0	0	0	0	0	0
119	E	- Clause	not_used									
120	E	SALES EXPENSES TOTAL (ACCT 916)		40,922	0	0	40,922	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	E											
122	E	TOTAL OPER & MAINT EXCL A&G		277,762,244	13,223,105	74,179	27,644,272	38,515,543	77,475,509	37,549,587	48,738,710	34,541,340
123	E											
124	E	ADMINISTRATIVE & GENERAL EXPENSE										
125	E	E920 A&G Salaries	REVREQ	5,694,688	253,543	168,533	1,119,362	908,950	368,498	496,556	1,166,655	1,212,591
126	E	E921 Office Supplies & Exp	REVREQ	622,444	27,713	18,421	122,349	99,351	40,278	54,275	127,518	132,539
127	E	E923 Outside Services Employed	DISTPLT	68,020,983	3,084,890	3,393,014	16,117,731	11,963,524	0	481,830	15,373,221	17,606,774
128	E	E924 Property Insurance	TOTPLT	1,802,573	80,587	88,637	421,207	312,527	21,772	17,472	401,599	458,772
129	E	E925 Injuries & Damages	LABOR	14,161,029	678,137	2,974	1,799,423	1,163,501	4,414,263	3,535,479	1,472,926	1,094,324
130	E	E926 Employee Pension & Benefits	LABOR	-77,966,713	-3,733,637	-16,373	-9,907,129	-6,405,917	-24,303,713	-19,465,372	-8,109,524	-6,025,047
131	E	E928 Regulatory Comm Exp	REVREQ	15,042,373	669,728	445,175	2,956,767	2,400,969	973,378	1,311,640	3,081,689	3,203,027
132	E	E929 Duplicate Charges - credit	REVLPLS	-3,363,888	0	-913	-676,371	-542,508	-127,369	-61,591	-906,020	-1,049,116
133	E	E930.1 General Advertising Expenses	CUSTAVG_04	2,277,517	0	0	2,277,517	0	0	0	0	0
134	E	E930.2 Misc General Expenses	DISTPLT	2,932,568	132,998	146,282	694,879	515,780	0	20,773	662,781	759,075
135	E	E931 Rents	DISTPLT	4,471,819	202,806	223,063	1,059,608	786,503	0	31,676	1,010,663	1,157,500
136	E	E932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0	0	0	0
137	E	E935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0	0	0	0
138	E	Not Used	not_used									
139	E	TOTAL A&G EXPENSE		33,695,393	1,396,765	4,468,813	15,985,344	11,202,679	-18,612,894	-13,577,262	14,281,508	18,550,439
140	E											
141	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325	63,020,218	53,091,779

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**										
2	DE											
3	DE	E403 DEPRECIATION EXPENSE										
4	DE	Production Plant	not_used	0	0	0	0	0	0	0	0	0
5	DE	Transmission Plant	not_used	0	0	0	0	0	0	0	0	0
6	DE	Distribution Plant	DISTPLT	257,769,144	11,690,355	12,858,009	61,079,002	45,336,411	0	1,825,920	58,257,639	66,721,808
7	DE	General Plant	GENPLT	19,786,964	928,885	1,021,663	4,620,908	3,602,311	0	0	4,628,997	4,984,200
8	DE	Common Plant	COMPLT	9,215,747	115,527	127,067	820,208	448,028	5,248,426	1,260,876	575,719	619,896
9	DE	Other Plant & Misc	DISTPLT	0	0	0	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
11	DE											
12	DE	E404.3 AMORT OF OTHER LIMITED TERM PLANT										
13	DE	not used	not_used	0	0	0	0	0	0	0	0	0
14	DE	Distribution Delivery Related	DISTPLTXMTR	6,072,872	285,087	313,561	1,418,216	1,105,595	0	0	1,420,698	1,529,715
15	DE	Meter Reading	MRCOST_07	492,670	0	0	0	0	0	492,670	0	0
16	DE	Customer Service related	CUSTSVSX	14,826,022	0	0	538,834	0	11,519,706	2,767,482	0	0
17	DE	not used	not_used	0	0	0	0	0	0	0	0	0
18	DE	not used	not_used	0	0	0	0	0	0	0	0	0
19	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
20	DE											
21	DE	E407 AMORT OF PROPERTY LOSSES										
22	DE	Regulatory assets	KWHMETER_04	0	0	0	0	0	0	0	0	0
23	DE	Securitization amortization	not_used	0	0	0	0	0	0	0	0	0
24	DE	not used	not_used	0	0	0	0	0	0	0	0	0
25	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0	0	0	0
26	DE											
27	DE	TOTAL AMORTIZATION EXPENSE		21,391,564	285,087	313,561	1,957,050	1,105,595	11,519,706	3,260,152	1,420,698	1,529,715
28	DE											
29	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948	64,883,053	73,855,618

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	EO	**OTHER OPERATING EXPENSES**										
2	EO	**E408 TAXES OTHER THAN INCOME TAXES**										
3	EO	TEFA	TEFA_04	0	0	0	0	0	0	0	0	0
4	EO	Real Estate Taxes	TOTPLT	0	0	0	0	0	0	0	0	0
5	EO	Miscellaneous State and Municipal Tax	TOTPLT	-275,485	-12,316	-13,546	-64,373	-47,763	-3,327	-2,670	-61,376	-70,114
6	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0	0	0	0
7	EO	FICA & UnempTax	LABOR	-11,275,732	-539,968	-2,368	-1,432,793	-926,439	-3,514,861	-2,815,129	-1,172,819	-871,357
8	EO	Other Taxes	TOTPLT	0	0	0	0	0	0	0	0	0
9	EO	not used	not_used	0	0	0	0	0	0	0	0	0
10	EO	**TOTAL TAXES OTHER THAN INCOME**		-11,551,217	-552,284	-15,914	-1,497,165	-974,202	-3,518,188	-2,817,799	-1,234,195	-941,470
11	EO	**PROFORMA EXPENSE ADJUSTMENTS**										
12	EO	Wage Increases (Rate Year)	LABOR	7,361,661	352,532	1,546	935,437	604,850	2,294,770	1,837,931	765,706	568,888
13	EO	Payroll Taxes (Rate Year)	LABOR	506,132	24,237	106	64,313	41,585	157,771	126,362	52,644	39,112
14	EO	Interest Syncronization	TOTPLTNET	-1,029,929	-47,542	-38,311	-238,454	-188,620	-6,606	-7,539	-243,337	-259,521
15	EO	- add'l tax effects on rev req	TOTPLTNET	-402,717	-18,589	-14,980	-93,239	-73,753	-2,583	-2,948	-95,148	-101,476
16	EO	Pension & Fringe Benefit (Rate Year)	LABOR	20,935,341	1,002,543	4,396	2,660,226	1,720,094	6,525,946	5,226,772	2,177,540	1,617,824
17	EO	COLI Interest Expense Recovery	LABOR	2,119,856	101,515	445	269,367	174,172	660,800	529,249	220,492	163,816
18	EO	- add'l tax effects on rev req	LABOR	828,893	39,694	174	105,326	68,104	258,382	206,944	86,215	64,055
19	EO	ASB Margin	TOTPLT	0	0	0	0	0	0	0	0	0
20	EO	BPU / Rate Counsel Assessment	KWHMETER_04	0	0	0	0	0	0	0	0	0
21	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0	0	0	0
22	EO	Gains / Losses Normalization	TOTPLT	-41,607	-1,860	-2,046	-9,722	-7,214	-503	-403	-9,270	-10,589
23	EO	- add'l tax effects on rev req	TOTPLT	-16,269	-727	-800	-3,802	-2,821	-197	-158	-3,625	-4,141
24	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0	0	0	0
25	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0	0	0	0
26	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	616,778	27,574	30,328	144,122	106,936	7,450	5,978	137,413	156,976
27	EO	Test Year Amortization Adjustments	TOTPLT	-17,276,070	-772,360	-849,505	-4,036,895	-2,995,292	-208,667	-167,453	-3,848,973	-4,396,926
28	EO	Insurance Premium Increases (Rate Year)	TOTPLT	482,666	21,579	23,734	112,785	83,684	5,830	4,678	107,534	122,843
29	EO	Rate Case Expenses	TOTPLT	188,766	8,439	9,282	44,109	32,728	2,280	1,830	42,055	48,043
30	EO	Depreciation Rate Change	DEPREXP	44,543,977	1,978,078	2,175,652	10,332,501	7,671,193	815,233	479,469	9,857,542	11,234,308
31	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0	0	0	0
32	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0	0	0	0
33	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0	0	0	0
34	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT	0	0	0	0	0	0	0	0	0
35	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0	0	0	0
36	EO	Test Year Corrections	TOTPLT									
37	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		83,562,007	2,846,163	1,490,990	11,078,806	7,890,398	10,152,215	29,822,614	10,094,506	10,186,317
38	EO											
39	EO	**TOTAL OTHER OPERATING EXPENSES**		72,010,790	2,293,879	1,475,076	9,581,640	6,916,195	6,634,026	27,004,816	8,860,311	9,244,846
40	EO	TOTAL OPERATING REVENUES	CALCULATED	1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675	387,005,653	402,129,014
41	EO	LESS:										
42	EO	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325	63,020,218	53,091,779
43	EO	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	308,163,419	13,019,854	14,320,300	68,477,169	50,492,344	16,768,132	6,346,948	64,883,053	73,855,618
44	EO	OTHER OPERATING EXPENSES	CALCULATED	72,010,790	2,293,879	1,475,076	9,581,640	6,916,195	6,634,026	27,004,816	8,860,311	9,244,846
45	EO	NET OPERATING INCOME BEFORE TAXES		1,196,353,939	54,052,811	35,449,238	249,433,135	194,262,476	39,860,850	107,116,586	250,242,071	265,936,771
46	EO	LESS:										
47	EO	E427 - E432 INTEREST CHARGES	TOTPLTNET	(137,585,275)	(6,350,955)	(5,117,857)	(31,854,346)	(25,197,165)	(882,434)	(1,007,114)	(32,506,750)	(34,668,654)
48	EO	**TOTAL OPERATING INCOME BEFORE TAXES**		1,333,939,214	60,403,767	40,567,095	281,287,480	219,459,641	40,743,284	108,123,700	282,748,821	300,605,425
49	EO	TSG-NF Gas Margin Reset		0	0	0	0	0	0	0	0	0
50	EO	Adjustment Reclassification Minus	ADJEXP_04	-17,563	0	0	-17,563	0	0	0	0	0
51	EO	Adjustment Reclassification Plus	ADJ_Plus_04	17,563	0	0	17,563	0	0	0	0	0
52	EO	Tax Bad Debt Adjustment	not_used	0	0	0	0	0	0	0	0	0
53	EO	Deferred Compensation & Severance Expense	LABOR	-1,199,974	-57,464	-252	-152,479	-98,592	-374,055	-299,589	-124,812	-92,731
54	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0	0
55	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0	0	0	0
56	EO	Amortization of CEF-EV Program Regulatory Assets	TOTPLTNET	4,303,381	198,645	160,076	996,338	788,115	27,601	31,500	1,016,744	1,084,363
57	EO	Amortization of CEF-EC Program Regulatory Assets	ECPRO_07	21,861,618	0	0	0	0	0	21,861,618	0	0
58	EO	Gas Bad Debt Adjustment		0	0	0	0	0	0	0	0	0
59	EO	BGS Administrative Expense Adjustment	A_GEXP	-220,495	-10,131	-8,857	-51,129	-34,771	-11,237	-11,627	-44,215	-48,528

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	TI	**DEVELOPMENT OF INCOME TAXES**										
2	TI	**TAX ADJUSTMENTS - FEDERAL**										
3	TI	Stock Based Compensation	TOTPLTNET	-328,125	-15,146	-12,206	-75,969	-60,092	-2,105	-2,402	-77,525	-82,681
4	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0	0	0
5	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0	0	0	0
6	TI	Uncollectible Accounts	REVREQ	0	0	0	0	0	0	0	0	0
7	TI	Injuries and Damages ;	TOTPLT	0	0	0	0	0	0	0	0	0
8	TI	Diesel Fuel Credit	not_used	0	0	0	0	0	0	0	0	0
9	TI	Partnership income/loss per K-1	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409	-9,394	-10,731
10	TI	Meals & entertainment	LABOR	-417,376	-19,987	-88	-53,035	-34,293	-130,104	-104,203	-43,412	-32,254
11	TI	Company owned life insurance	LABOR	0	0	0	0	0	0	0	0	0
12	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-1,032,350	-47,653	-38,401	-239,014	-189,063	-6,621	-7,557	-243,909	-260,131
13	TI	Medicare Subsidy	LABOR	0	0	0	0	0	0	0	0	0
14	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0	0	0	0
15	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,841,683	88,194	387	234,020	151,317	574,088	459,799	191,558	142,320
16	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0	0	0	0
17	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0	0
18	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0	0	0	0
19	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0	0
20	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0	0
21	TI	AFUDC / IDC	TOTPLT	-1,076,666	-48,134	-52,942	-251,584	-186,670	-13,004	-10,436	-239,873	-274,022
22	TI	Capitalized interest-Section 263A	TOTPLT	3,363,340	150,365	165,383	785,911	583,129	40,624	32,600	749,326	856,002
23	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0	0	0
24	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0	0
25	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0	0
26	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0	0
27	TI	Deferred Comp - officers	LABOR	11,058	530	2	1,405	909	3,447	2,761	1,150	855
28	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0	0
29	TI	Accrued vacation pay adjustment	LABOR	-344,695	-16,507	-72	-43,800	-28,321	-107,448	-86,057	-35,853	-26,637
30	TI	3rd Party Claims	TOTPLT	87,346	3,905	4,295	20,410	15,144	1,055	847	19,460	22,230
31	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0	0	0
32	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0	0
33	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0	0
34	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0	0	0
35	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0	0
36	TI	Contribution in Aid of Construct	TOTPLTNET	905,779	41,811	33,693	209,710	165,883	5,809	6,630	214,005	228,238
37	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0	0
38	TI	Pension Accrual Adjustment	LABOR	-3,671,962	-175,841	-771	-466,591	-301,697	-1,144,621	-916,752	-381,931	-283,759
39	TI	Unallowable OPEB Amortization	LABOR	-105,080,197	-5,032,036	-22,067	-13,352,404	-8,633,621	-32,755,504	-26,234,595	-10,929,669	-8,120,301
40	TI	Deferred Return on CIP II	TOTPLT	66,348	2,966	3,263	15,504	11,503	801	643	14,782	16,886
41	TI	Deferred Depreciation on CIP II	TOTPLT	52,458	2,345	2,580	12,258	9,095	634	508	11,687	13,351
42	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0	0
43	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	91,151	4,208	3,391	21,104	16,693	585	667	21,536	22,968
44	TI	Misc Adj - Permanent	TOTPLTNET	0	0	0	0	0	0	0	0	0
45	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	1,120,547	51,725	41,682	259,434	205,215	7,187	8,202	264,747	282,355
46	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-1,045,327	-48,252	-38,884	-242,019	-191,440	-6,704	-7,652	-246,975	-263,401
47	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**										
48	TI	**TAX ADJUSTMENTS - FEDERAL CONTINUED**										
49	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0	0
50	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0	0
51	TI	Penalties	not_used	0	0	0	0	0	0	0	0	0
52	TI	Restricted Stock - Permanent	TOTPLTNET	-82,615	-3,814	-3,073	-19,128	-15,130	-530	-605	-19,519	-20,817
53	TI	Environmental Accrual	TOTPLTNET	0	0	0	0	0	0	0	0	0
54	TI	Legal Reserves (c & nc)	TOTPLTNET	401,853	18,550	14,948	93,039	73,595	2,577	2,942	94,944	101,259
55	TI	Material Supplies & Reserves	TOTPLT	107,143	4,790	5,268	25,036	18,576	1,294	1,039	23,871	27,269
56	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0	0	0	0
57	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	62,834	2,900	2,337	14,548	11,507	403	460	14,846	15,833
58	TI	Real Estate Taxes	TOTPLTNET	1,046,714	48,316	38,935	242,340	191,694	6,713	7,662	247,303	263,750
59	TI	Credits & Adjustments	TOTPLTNET	0	0	0	0	0	0	0	0	0
60	TI	**Miscellaneous**	TOTPLT									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-149,324,736	-7,017,220	-1,824,302	-22,552,940	-15,194,328	-36,673,211	-29,240,133	-19,332,171	-17,490,432
62	TI											
63	TI	**TAX ADJUSTMENTS - STATE**										
64	TI	TEFA	TEFA_04	0	0	0	0	0	0	0	0	0
65	TI	Federal Depreciation Reversal	DEPREXP	72,042,765	3,199,226	3,518,770	16,711,170	12,406,929	1,318,508	775,464	15,942,999	18,169,698
66	TI	State Tax Depreciation	DEPREXP	36,681,624	1,628,932	1,791,633	8,508,736	6,317,169	671,338	394,839	8,117,611	9,251,367
67	TI	not used	not_used	0	0	0	0	0	0	0	0	0
68	TI	**TOTAL TAX ADJUSTMENTS - STATE**		108,724,389	4,828,158	5,310,403	25,219,906	18,724,097	1,989,846	1,170,303	24,060,610	27,421,065
69	TI											
70	TI	**TAXABLE NET INCOME - STATE**		1,293,338,867	58,214,705	44,053,196	283,954,447	222,989,410	6,059,920	80,053,871	287,477,261	310,536,058
71	TI	State Tax Liability		116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848	25,872,953	27,948,245
72	TI	Prior Year Adjustment	TOTPLTNET	0	0	0	0	0	0	0	0	0
73	TI	**TOTAL STATE INCOME TAX LIABILITY**		116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848	25,872,953	27,948,245
74	TI											
75	TI	**TAXABLE NET INCOME - FEDERAL**		1,068,213,981	48,147,223	34,778,006	233,178,640	184,196,266	3,524,681	71,678,719	237,543,697	255,166,748
76	TI	Federal Tax Liability		224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531	49,884,176	53,585,017
77	TI	not used	not_used	0	0	0	0	0	0	0	0	0
78	TI	not used	not_used	0	0	0	0	0	0	0	0	0
79	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		224,324,936	10,110,917	7,303,381	48,967,514	38,681,216	740,183	15,052,531	49,884,176	53,585,017
80	TI											
81	TI	**TOTAL INCOME TAX EXPENSE**		340,725,434	15,350,240	11,268,169	74,523,415	58,750,263	1,285,576	22,257,379	75,757,130	81,533,262
82	TI											
83	TI											
84	TI											
85	TI	**TAX RATES**										
86	TI	FEDERAL TAX RATE - CURRENT		21.000%								
87	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%								
88	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000								
89	TI	EFFECTIVE TAX RATE		28.110%								
90	TI	COMPOSITE RATE		28.110%								
91	TI	1 - EFFECTIVE TAX RATE		71.89000%								
92	TI											
93	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**										
94	TI	**E410 + E411- PROVISION FOR DEFERRED INCOME TAX**										
95	TI	Legal Reserves (c)	TOTPLTNET	0	0	0	0	0	0	0	0	0
96	TI	Tax Depreciation	DEPREXP	0	0	0	0	0	0	0	0	0
97	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0	0	0	0
98	TI	Amortization of Power Gain	not_used	0	0	0	0	0	0	0	0	0
99	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0	0	0	0
100	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0	0	0	0
101	TI	AFUDC / IDC	TOTPLT	1,076,666	48,134	52,942	251,584	186,670	13,004	10,436	239,873	274,022
102	TI	Capitalized interest-Section 263A	TOTPLT	-3,363,340	-150,365	-165,383	-785,911	-583,129	-40,624	-32,600	-749,326	-856,002
103	TI	Cost of removal	TOTPLT	0	0	0	0	0	0	0	0	0
104	TI	Utility Commodity Costs	not_used	0	0	0	0	0	0	0	0	0
105	TI	RAC-Environmental Cleanup Costs	not_used	0	0	0	0	0	0	0	0	0
106	TI	SBC-Societal Benefits Clause	not_used	0	0	0	0	0	0	0	0	0
107	TI	Deferred Comp - officers	LABOR	-11,058	-530	-2	-1,405	-909	-3,447	-2,761	-1,150	-855
108	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0	0	0	0
109	TI	Accrued vacation pay adjustment	LABOR	344,695	16,507	72	43,800	28,321	107,448	86,057	35,853	26,637
110	TI	3rd Party Claims	TOTPLT	-87,346	-3,905	-4,295	-20,410	-15,144	-1,055	-847	-19,460	-22,230
111	TI	Bankruptcies & Acc Prov-Rent Receivable	LABOR	0	0	0	0	0	0	0	0	0
112	TI	Deduction for New Network Meter Equipment	TOTPLT	0	0	0	0	0	0	0	0	0
113	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0	0	0	0
114	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0	0	0	0
115	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0	0	0	0
116	TI	Repair Allow Deferral Carrying Charges	TOTPLT	0	0	0	0	0	0	0	0	0
117	TI	Contribution in Aid of Construct	TOTPLTNET	-905,779	-41,811	-33,693	-209,710	-165,883	-5,809	-6,630	-214,005	-228,238
118	TI	FIN48 Services Allocation	TOTPLT	0	0	0	0	0	0	0	0	0
119	TI	Pension Accrual Adjustment	LABOR	3,671,962	175,841	771	466,591	301,697	1,144,621	916,752	381,931	283,759
120	TI	Unallowable OPEB Amortization	LABOR	105,080,197	5,032,036	22,067	13,352,404	8,633,621	32,755,504	26,234,595	10,929,669	8,120,301

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0	0	0	0
122	TI	Conditional Asset Retire Obligations	TOTPLTNET	0	0	0	0	0	0	0	0	0
123	TI	Rabbi Trust Unrealized Losses	LABOR	0	0	0	0	0	0	0	0	0
124	TI	FIN48 Reg Asset Reversal	LABOR	0	0	0	0	0	0	0	0	0
125	TI	Additional Real Estate Taxes	TOTPLT	108,083	4,832	5,315	25,256	18,739	1,305	1,048	24,080	27,508
126	TI	PIP Adjustment	LABOR	1,045,327	50,058	220	132,828	85,886	325,848	260,979	108,727	80,780
127	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0	0	0	0
128	TI	Misc	TOTPLT	0	0	0	0	0	0	0	0	0
129	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0	0	0	0
130	TI	Deferred Return on CIP II	TOTPLT	-66,348	-2,966	-3,263	-15,504	-11,503	-801	-643	-14,782	-16,886
131	TI	Deferred Depreciation on CIP II	TOTPLT	-52,458	-2,345	-2,580	-12,258	-9,095	-634	-508	-11,687	-13,351
132	TI	Customer Connections Fees	CUSTACCTS	-6,684,538	0	0	-114,268	0	-5,252,212	-1,318,058	0	0
133	TI	Decommissioning Costs	KWHMETER_04	0	0	0	0	0	0	0	0	0
134	TI	Investment Tax Credit	TOTPLT	0	0	0	0	0	0	0	0	0
135	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-91,151	-4,208	-3,391	-21,104	-16,693	-585	-667	-21,536	-22,968
136	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	0	0	0	0	0	0	0	0	0
137	TI	GainState LILOAudit Refunds not yet received	TOTPLTNET	0	0	0	0	0	0	0	0	0
138	TI	LCAPP	TOTPLTNET	0	0	0	0	0	0	0	0	0
139	TI	Audit Adjustment	not_used	0	0	0	0	0	0	0	0	0
140	TI	Stock Based Compensation	TOTPLTNET	328,125	15,146	12,206	75,969	60,092	2,105	2,402	77,525	82,681
141	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0	0	0	0
142	TI	Legal Reserves (nc)	TOTPLTNET	-401,853	-18,550	-14,948	-93,039	-73,595	-2,577	-2,942	-94,944	-101,259
143	TI											
144	TI											
145	TI	**DEVELOPMENT OF OPERATING INCOME ADJ CONTINUE**										
146	TI	**E410 + E411- PROVISION FOR DEFER INC TAX CONTINU**										
147	TI	Material Supplies & Reserves	TOTPLTNET	-107,143	-4,946	-3,985	-24,806	-19,622	-687	-784	-25,314	-26,998
148	TI	Medicare Subsidy	TOTPLTNET									
149	TI	**TOTAL DEFERRED INCOME TAX**		144,525,616	7,115,721	1,779,204	22,716,135	15,444,321	31,830,837	28,280,881	19,656,221	17,702,297
150	TI											
151	TI	**TOTAL INC TAXES DEF IN PRIOR YEAR**	not_used	0	0	0	0	0	0	0	0	0
152	TI	**TOTAL INVEST TAX CRED ADJ (NET)**	not_used	0	0	0	0	0	0	0	0	0
153	TI	**TOTAL PRO FORMA OP INC ADJUSTMENTS**	not_used	0	0	0	0	0	0	0	0	0
154	TI											
155	TI	**OPERATING INCOME ADJUSTED**		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
156	TI	Severance Pay (nc)	LABOR	154,681	7,407	32	19,655	12,709	48,217	38,618	16,089	11,953
157	TI	CEF- EV Deferral	TOTPLT	1,855,840	82,969	91,256	433,654	321,762	22,416	17,988	413,467	472,329
158	TI	CEF- EC AMI	TOTPLT	20,866,765	932,889	1,026,067	4,875,932	3,617,839	252,036	202,257	4,648,952	5,310,793
159	TI	Casualty Loss Deferred O&M	TOTPLTNET	-1,120,547	-51,725	-41,682	-259,434	-205,215	-7,187	-8,202	-264,747	-282,355
160	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	53,745	2,403	2,643	12,559	9,318	649	521	11,974	13,679
161	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0	0
162	TI	Additional Rental Income - NJ Properties	TOTPLT	-16,349	-731	-804	-3,820	-2,835	-197	-158	-3,642	-4,161
163	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
164	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0	0	0	0
165	TI	Additional Rental Income - NJ Properties	TOTPLT	16,349	731	804	3,820	2,835	197	158	3,642	4,161
166	TI	Additional Expenses on Rental Property	TOTPLT	-108,083	-4,832	-5,315	-25,256	-18,739	-1,305	-1,048	-24,080	-27,508
167	TI	Unrealized G/L on Equity Securities	TOTPLT	-125,367	-5,605	-6,165	-29,295	-21,736	-1,514	-1,215	-27,931	-31,907
168	TI	Medicare Subsidy	not_used	0	0	0	0	0	0	0	0	0
169	TI	State NOL CF (c)	DEPREXP	-17,908,279	-795,259	-874,690	-4,154,037	-3,084,095	-327,753	-192,764	-3,963,086	-4,516,596
170	TI	Severance Pay (nc)	LABOR	-154,681	-7,407	-32	-19,655	-12,709	-48,217	-38,618	-16,089	-11,953
171	TI	Reversal of Book Income from Partnerships	TOTPLT	-42,165	-1,885	-2,073	-9,853	-7,310	-509	-409	-9,394	-10,731
172	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0	0
173	TI	Real Estate Taxes (nc)	TOTPLT	-1,046,714	-46,795	-51,469	-244,585	-181,477	-12,643	-10,146	-233,200	-266,399
174	TI	RE - ROU Lease Asset	TOTPLT	-319,172	-14,269	-15,694	-74,581	-55,337	-3,855	-3,094	-71,109	-81,232
175	TI	RE - Lease Liability	TOTPLT	236,259	10,562	11,617	55,207	40,962	2,854	2,290	52,637	60,130
176	TI	R & D Credits CF	TOTPLT	-15,263	-682	-751	-3,566	-2,646	-184	-148	-3,400	-3,885
177	TI	Plant Related	DEPREXP	37,305,084	1,656,619	1,822,084	8,653,355	6,424,538	682,748	401,550	8,255,582	9,408,608
178	TI	Partnership Income/Loss (nc)	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409	9,394	10,731
179	TI	Injuries & Damages - FT	TOTPLT	-328,505	-14,686	-16,153	-76,762	-56,956	-3,968	-3,184	-73,188	-83,608
180	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
181	TI	Deferred Employer ER FICA	LABOR	7,086,760	339,368	1,488	900,505	582,264	2,209,078	1,769,299	737,113	547,645
182	TI	Deduction for Retention Payments (c)	LABOR	5,352	256	1	680	440	1,668	1,336	557	414
183	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0	0
184	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0	0
185	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0	0
186	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0	0
187	TI	Customer Advances	TOTPLTNET	-4,645,423	-214,433	-172,799	-1,075,529	-850,756	-29,794	-34,004	-1,097,556	-1,170,551
188	TI	Current SHARE -- FT	DEPREXP	2,912,070	129,317	142,234	675,489	501,506	53,296	31,345	644,439	734,445
189	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
190	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
191	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0	0	0
192	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0	0	0
193	TI	CECL Reserve	not_used	0	0	0	0	0	0	0	0	0
194	TI	Reversal of Book Income from Partnerships	TOTPLT	42,165	1,885	2,073	9,853	7,310	509	409	9,394	10,731
195	TI	RE - ROU Lease Asset	TOTPLT	319,172	14,269	15,694	74,581	55,337	3,855	3,094	71,109	81,232
196	TI	RE - Lease Liability	TOTPLT	-236,259	-10,562	-11,617	-55,207	-40,962	-2,854	-2,290	-52,637	-60,130
197	TI	Rabbi Trust	not_used	0	0	0	0	0	0	0	0	0
198	TI	R & D Credits CF	not_used	0	0	0	0	0	0	0	0	0
199	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0	0	0	0
200	TI	Plant Related	DEPREXP	-33,454,683	-1,485,633	-1,634,020	-7,760,209	-5,761,437	-612,279	-360,104	-7,403,492	-8,437,509
201	TI	R&D Expenditure	TOTPLT	-5,622	-251	-276	-1,314	-975	-68	-54	-1,253	-1,431
202	TI	Qualified Transportation Fringe	LABOR	162,269	7,771	34	20,619	13,332	50,582	40,512	16,878	12,540
203	TI	Entertainment (100%)	LABOR	38,419	1,840	8	4,882	3,157	11,976	9,592	3,996	2,969
204	TI	Diesel Fuel Tax Credit	TOTPLT	82	4	4	19	14	1	1	18	21
205	TI	Company Owned Life Insurance - Tax	LABOR	-58,279	-2,791	-12	-7,405	-4,788	-18,167	-14,550	-6,062	-4,504
206	TI	Company Owned Life Insurance - Book	LABOR	-1,117,127	-53,497	-235	-141,952	-91,786	-348,230	-278,905	-116,195	-86,328
207	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	11,771	526	579	2,751	2,041	142	114	2,623	2,996
208	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0	0	0	0
209	TI	Injuries & Damages - FT	TOTPLT	1,298,774	58,064	63,864	303,484	225,179	15,687	12,589	289,357	330,550
210	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0	0	0	0
211	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0	0	0	0
212	TI	Deferred Employer ER FICA	LABOR	-7,086,760	-339,368	-1,488	-900,505	-582,264	-2,209,078	-1,769,299	-737,113	-547,645
213	TI	Deduction for Retention Payments (c)	LABOR	-5,352	-256	-1	-680	-440	-1,668	-1,336	-557	-414
214	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	6,684,538	308,559	248,650	1,547,634	1,224,197	42,873	48,930	1,579,330	1,684,366
215	TI	Customer Advances	TOTPLTNET	4,645,423	214,433	172,799	1,075,529	850,756	29,794	34,004	1,097,556	1,170,551
216	TI	Current SHARE -- FT	DEPREXP	-11,513,122	-511,267	-562,333	-2,670,605	-1,982,746	-210,710	-123,927	-2,547,844	-2,903,691
217	TI	COVID Deferrals	not_used	0	0	0	0	0	0	0	0	0
218	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0	0	0	0
219	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0	0	0	0
220	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0	0	0	0
221	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0	0	0	0
222	TI	CEF- EV Deferral	TOTPLT	-1,855,840	-82,969	-91,256	-433,654	-321,762	-22,416	-17,988	-413,467	-472,329
223	TI	CEF- EC AMI	TOTPLT	-20,866,765	-932,889	-1,026,067	-4,875,932	-3,617,839	-252,036	-202,257	-4,648,952	-5,310,793
224	TI	CECL Reserve	not_used	0	0	0	0	0	0	0	0	0
225	TI	Unrealized G/L on Equity Securities	TOTPLT	125,367	5,605	6,165	29,295	21,736	1,514	1,215	27,931	31,907
226	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0	0	0	0
227	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-460,907	-20,606	-22,664	-107,700	-79,911	-5,567	-4,467	-102,686	-117,305
228	TI	State NOL CF (c)	DEPREXP	17,908,279	795,259	874,690	4,154,037	3,084,095	327,753	192,764	3,963,086	4,516,596

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**										
2	LR											
3	LR	**PRODUCTION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0	0
4	LR											
5	LR	**TRANSMISSION LABOR EXPENSE**	not_used	0	0	0	0	0	0	0	0	0
6	LR											
7	LR	**DISTRIBUTION LABOR EXPENSE**											
8	LR	Operation										
9	LR	582-Station Equipment	E367PLT	280,636	663	40	91,778	40,746	0	0	48,427	98,982
10	LR	583-Overhead Lines	E367PLT	941,919	2,225	135	308,041	136,758	0	0	162,538	332,222
11	LR	584-Underground Lines	E367PLT	4,591,058	10,845	659	1,501,438	666,578	0	0	792,237	1,619,301
12	LR	586-Metering	MTROMMIN_07	4,311,826	0	0	0	0	0	4,311,826	0	0
13	LR	587-Customer Installations	MTROMMIN_07	17,308,754	0	0	0	0	0	17,308,754	0	0
14	LR	588-Miscellaneous	DISTEXPO	16,169,609	186,473	1,522	391,230	2,925,275	0	5,802,178	3,667,762	3,195,169
15	LR	Total Operation		43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758	4,670,963	5,245,674
16	LR	Maintenance										
17	LR	590-Supervision & Engineering	DISTEXPM	0	0	0	0	0	0	0	0	0
18	LR	591-Structures	E361PLT	2,559,859	0	0	0	1,095,258	0	0	1,464,601	0
19	LR	592-Station Equipment	E362PLT	8,699,368	0	0	0	3,722,100	0	0	4,977,268	0
20	LR	593-Overhead Lines	E365PLT	11,294,340	34,257	0	2,673,491	2,605,807	0	0	3,181,313	2,799,472
21	LR	594-Underground Lines	E367PLT	11,333,758	26,773	1,627	3,706,538	1,645,555	0	0	1,955,763	3,997,502
22	LR	595-Line Transformers	LNTRFRMR_04	2,457,581	0	0	2,457,581	0	0	0	0	0
23	LR	596-Street Lighting and Signal Systems	E373PLT	7,842,365	7,299,789	29,395	132,951	103,644	0	0	133,183	143,403
24	LR	597-Meters	MTROMMIN_07	700,642	0	0	0	0	0	700,642	0	0
25	LR	598-Other Distribution Maintenance	DISTEXPM	529,302	53,426	12	95,281	122,632	0	770	155,630	101,549
26	LR	Total Maintenance		45,417,214	7,414,246	31,034	9,065,842	9,294,996		701,413	11,867,757	7,041,925
27	LR	TOTAL DISTRIBUTION LABOR EXPENSE		89,021,016	7,614,452	33,391	11,358,327	13,064,353	0	28,124,171	16,538,721	12,287,599
28	LR											
29	LR	**E901-E903,E905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	58,697,026	0	0	1,003,385	0	46,119,752	11,573,889	0	0
30	LR	**E907-E910, xDSM CUST SERV & INFO EXP**	CUSTS_I	5,539,923	0	0	2,094,208	0	3,445,715	0	0	0
31	LR	**E911-E916 SALES EXPENSE**	SALESEXP	0	0	0	0	0	0	0	0	0
32	LR	**ADMIN & GENERAL EXP ACCOUNTS xE926**	SALESEXP	5,748,870	0	0	5,748,870	0	0	0	0	0
33	LR	**Employee Pension/Benefits Acct E926**	LABOR	0	0	0	0	0	0	0	0	0
34	LR											
35	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060	16,538,721	12,287,599

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION										
1	CA	**FACTOR**										
2	CA											
3	CA	**INTANGIBLE PLANT**	not_used	0	0	0	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT**	not_used	0	0	0	0	0	0	0	0	0
5	CA											
6	CA	**TRANSMISSION PLANT**										
7	CA	E352 Structure & Improvements	not_used	0	0	0	0	0	0	0	0	0
8	CA	E353 Station Equipment	not_used	0	0	0	0	0	0	0	0	0
9	CA	E354/355 Towers and Fixtures	not_used	0	0	0	0	0	0	0	0	0
10	CA	E356 OH Cond and Devices	not_used	0	0	0	0	0	0	0	0	0
11	CA	E357 UG Conduits	not_used	0	0	0	0	0	0	0	0	0
12	CA	E358 Underground Cond. and Devices	not_used	0	0	0	0	0	0	0	0	0
13	CA	E359 Roads and Trails	not_used	0	0	0	0	0	0	0	0	0
14	CA	Other Tangible Plant Unallocated	not_used	0	0	0	0	0	0	0	0	0
15	CA	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0
16	CA											
17	CA	**DISTRIBUTION PLANT**										
18	CA	E360 Land and Land Rights	E360PLT	3,481,598	0	0	0	1,489,632	0	0	1,991,966	0
19	CA	E361 Structures and Improvements	E361PLT	1,433,350	0	0	0	613,271	0	0	820,079	0
20	CA	E362 Station Equipment	E362PLT	72,557,752	0	0	0	31,044,465	0	0	41,513,287	0
21	CA	E364 Poles Towers and Fixtures	E364PLT	86,501,520	835,763	0	27,289,006	11,682,762	0	0	17,165,182	29,528,807
22	CA	E365 OH Conductors and Dev.	E365PLT	235,018,380	712,839	0	55,631,373	54,222,955	0	0	66,198,377	58,252,835
23	CA	E366 Underground Conduits	E367PLT	3,221,386	7,610	462	1,053,507	467,715	0	0	555,885	1,136,207
24	CA	E367 Underground Cond. and Dev.	E367PLT	32,807,746	77,501	4,710	10,729,288	4,763,375	0	0	5,661,333	11,571,539
25	CA	E368 Line Transformers - Energy Related - Local	KWH_SEC_10	48,751,051	0	0	0	0	0	0	0	48,751,051
26	CA	E368 Line Transformers - Demand Related - Local	CP_SEC_04	44,108,093	0	0	44,108,093	0	0	0	0	0
27	CA	E369 Services	E369PLT	11,962,969	0	11,962,969	0	0	0	0	0	0
28	CA	E370 Meters	METERPLT	73,420,491	0	0	24,547,943	0	0	15,333,598	0	33,538,951
29	CA	E373 Street Lighting	E373PLT	39,887,684	37,128,046	149,507	676,211	527,152	0	0	677,394	729,374
30	CA	E374 Asset Retirement Obligations	TOTPLT									
31	CA	TOTAL DISTRIBUTION PLANT		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598	134,583,502	183,508,763
32	CA											
33	CA	**TOTAL CAPITAL ADDITIONS**		653,152,020	38,761,759	12,117,649	164,035,421	104,811,328	0	15,333,598	134,583,502	183,508,763

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	AF	**ALLOCATION FACTOR TABLE**										
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
3	AF											
4	AF	**ALLOCATION FACTORS PART A**										
5	AF											
6	AF	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	2,318,149	0	0	2,318,149	0	0	0	0	0
7	AF											
8	AF											
9	AF	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	3,519,017	0	0	0	3,519,017	0	0	0	0
10	AF	CP @ primary lines - systems	CP_PRI_05	8,928,659	0	0	0	8,928,659	0	0	0	0
11	AF	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	21,256,013	0	0	21,256,013	0	0	0	0	0
12	AF	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	19,856,464	0	0	19,856,464	0	0	0	0	0
13	AF	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	20,498,179	0	0	20,498,179	0	0	0	0	0
14	AF											
15	AF											
16	AF	CP @ secondary lines - local	CP_SEC_04	8,231,675	0	0	8,231,675	0	0	0	0	0
17	AF	CP @ primary lines - local	CP_PRI_04	8,928,659	0	0	8,928,659	0	0	0	0	0
18	AF	NCP @ meter - local	NCP_MTR_04	10,800,203	0	0	10,800,203	0	0	0	0	0
19	AF	NCP @ meter - measurement	NCP_MTR_07	10,800,203	0	0	0	0	0	10,800,203	0	0
20	AF	NCP @ meter - cust svs	NCP_MTR_06	10,800,203	0	0	0	0	10,800,203	0	0	0
21	AF	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	10,698,184	0	0	0	0	0	10,698,184	0	0
22	AF	**BILLING DETERMINANTS**										
23	AF											
24	AF	Number of Customers		2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219	2,348,219
25	AF	Delivered kWh @ Meter - annual (w/n net)		40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119	40,231,265,119
26	AF	Delivered Kw @ Meter - annual		0	0	0	0	0	0	0	0	0
27	AF											
28	AF											
29	AF	**ALLOCATION FACTORS PART B**										
30	AF											
31	AF	Delivery kWh @ meter	KWHMETER_04	40,816,033,564	0	0	40,816,033,564	0	0	0	0	0
32	AF	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	21,338,981,079	0	0	21,338,981,079	0	0	0	0	0
33	AF	Delivery kWh @ subtrans - System E	KWH_SUBT_09	12,282,908,123	0	0	0	0	0	0	12,282,908,123	0
34	AF	Delivery kWh @ primary - System E	KWH_PRI_09	36,303,573,183	0	0	0	0	0	0	36,303,573,183	0
35	AF	Delivery kWh @ primary - Local E	KWH_PRI_10	36,303,573,183	0	0	0	0	0	0	0	36,303,573,183
36	AF	Delivery kWh @ secondary - Local E	KWH_SEC_10	32,329,765,823	0	0	0	0	0	0	0	32,329,765,823
37	AF	Delivery kWh @ meter - measurement	KWHMETER_07	40,781,263,034	0	0	0	0	0	40,781,263,034	0	0
38	AF	Delivery kWh @ meter - cust svs	KWHMETER_06	40,781,263,034	0	0	0	0	40,781,263,034	0	0	0
39	AF											
40	AF											
41	AF	**ALLOCATION FACTORS PART C**										
42	AF											
43	AF	Avg Customer Bills - measurement	CUSTAVG_07	2,335,622	0	0	0	0	0	2,335,622	0	0
44	AF	E370 excess meter investment - local delivery - Demand	METERSEXC_04	124,473,055	0	0	124,473,055	0	0	0	0	0
45	AF	E370 excess meter investment - local delivery - Energy	METERSEXC_10	124,473,055	0	0	0	0	0	0	0	124,473,055
46	AF	Meter O&M - measurement	METERPLT_07	456,573,728	0	0	0	0	0	456,573,728	0	0
47	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
48	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
49	AF											
50	AF	E370 excess mtr invst - measrmnt	METERSEXC_07	124,473,055	0	0	0	0	0	124,473,055	0	0
51	AF	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0	0	0	0	0	0	0	0	0
52	AF	E587 Customer Installation Expenses Local	CUSINT_04	112	0	0	112	0	0	0	0	0
53	AF	E587 Customer Installation Expenses System	CUSINT_05	112	0	0	0	112	0	0	0	0
54	AF	Draft EC Proforma	ECPRO_07	434,841,736	0	0	0	0	0	434,841,736	0	0
55	AF	Expense Reclassification-local	ADJEXP_04	-17,563	0	0	-17,563	0	0	0	0	0
56	AF	Expense Reclassification Plus-local	ADJ_Plus_04	17,563	0	0	17,563	0	0	0	0	0
57	AF	E369 minimum Service investment- access	SERVICESMIN_03	360,747,418	0	360,747,418	0	0	0	0	0	0
58	AF	E369 excess Service investment- local delivery	SERVICESEXC_04	709,786,184	0	0	709,786,184	0	0	0	0	0
59	AF	Avg Customer Bills - local	CUSTAVG_04	2,348,219	0	0	2,348,219	0	0	0	0	0
60	AF	Avg Customer Bills - cust svs	CUSTAVG_06	2,348,219	0	0	0	0	2,348,219	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	AF	E370 minimum meter investment - measurement	METERSMIN_07	191,661,323	0	0	0	0	0	191,661,323	0	0
62	AF	E368 Line Transfomers - local	LNTRFRMR_04	559,887,636	0	0	559,887,636	0	0	0	0	0
63	AF	Billing Function costs - cust svs	BILLING_06	130,951	0	0	0	0	130,951	0	0	0
64	AF	Account Maint - cust svs	ACCTMAINT_06	80,564,013	0	0	0	0	80,564,013	0	0	0
65	AF	Meter Reading Costs - measurement	MRCOST_07	20,538,511	0	0	0	0	0	20,538,511	0	0
66	AF	Sales	SALES_06	0	0	0	0	0	0	0	0	0
67	AF	Other Utility work by Cust Ops - local	UTILWORK_04	3,334,747	0	0	3,334,747	0	0	0	0	0
68	AF											
69	AF											
70	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
71	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
72	AF											
73	AF	Choice - local	CHOICE_04	0	0	0	0	0	0	0	0	0
74	AF											
75	AF	Direct - PSAL - streetlighting	DIR_PSAL_02	1	1	0	0	0	0	0	0	0
76	AF	Direct - BPL - streetlighting	DIR_BPL_02	1	1	0	0	0	0	0	0	0
77	AF	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1	1	0	0	0	0	0	0	0
78	AF	Direct - HTS-HV - access	DIR_HTSHV_03	1	0	1	0	0	0	0	0	0
79	AF	Direct - HEP - access	DIR_HEP_03	0	0	0	0	0	0	0	0	0
80	AF	Direct - HTS-Sub - systems	DIR_HTSS_05	1	0	0	0	1	0	0	0	0
81	AF											
82	AF	Direct - HTS-Sub - local	DIR_HTSS_04	1	0	0	1	0	0	0	0	0
83	AF	Meter O&M - minimum - measurement	MTROMMIN_07	6,387,137	0	0	0	0	0	6,387,137	0	0
84	AF	Meter O&M - excess - measurement	MTROMEXC_07	0	0	0	0	0	0	0	0	0
85	AF	WN TEFA Responsibility	TEFA_04	0	0	0	0	0	0	0	0	0
86	AF											
87	AF	E370 excess meter investment - dummy	METERSEXC_08	5,064	0	0	0	0	0	0	0	0
88	AF	Meter O&M - excess - dummy	MTROMEXC_08	0	0	0	0	0	0	0	0	0
89	AF	E369 excess Service investment- dummy	SERVICESEXC_08	0	0	0	0	0	0	0	0	0
90	AF	E368 Line Transfomers - dummy	LNTRFRMR_08	0	0	0	0	0	0	0	0	0
91	AF	CP @ primary lines - dummy	CP@PRI_08	0	0	0	0	0	0	0	0	0
92	AF	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0	0	0	0	0	0	0	0	0
93	AF											
94	AF											
95	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0	0	0	0
96	AF											
97	AF	**Plant Related**										
98	AF	Distribution Plant Total	DISTPLT	10,773,828,418	488,615,049	537,418,784	2,552,883,868	1,894,899,857	0	76,316,914	2,434,960,990	2,788,732,956
99	AF	Distribution Plant x meters	DISTPLTXMTR	10,408,406,976	488,615,049	537,418,784	2,430,706,197	1,894,899,857	0	0	2,434,960,990	2,621,806,099
100	AF	Acct E360 - Land & Land Rights	E360PLT	51,314,168	0	0	0	21,955,213	0	0	29,358,955	0
101	AF	Acct E361 - Structures & Improvments	E361PLT	242,256,447	0	0	0	103,651,528	0	0	138,604,918	0
102	AF	Acct E362 - Station Equipment	E362PLT	1,565,418,169	0	0	0	669,777,783	0	0	895,640,386	0
103	AF	Acct E364 - Poles & Towers	E364PLT	1,027,443,483	9,926,985	0	324,132,007	138,764,932	0	0	203,883,749	350,735,810
104	AF	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	2,856,184,590	8,663,157	0	676,089,548	658,973,011	0	0	804,510,629	707,948,244
105	AF	Acct E366 - UG Conduit	E366PLT	512,107,003	1,209,731	73,522	167,477,027	74,353,110	0	0	88,369,620	180,623,992
106	AF	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1,431,183,475	3,380,831	205,472	468,047,404	207,794,351	0	0	246,966,239	504,789,178
107	AF	Acct E369 Services	E369PLT	535,269,333	0	535,269,333	0	0	0	0	0	0
108	AF	Acct E370 Meters	METERPLT	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
109	AF	Acct E370 Meters x load profile meters	METERPLTXPR	365,421,442	0	0	122,177,671	0	0	76,316,914	0	166,926,857
110	AF	Acct E373 - Streetlights	E373PLT	499,027,153	464,501,858	1,870,457	8,459,940	6,595,096	0	0	8,474,749	9,125,053
111	AF	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.0000			0.2110	0.7890				
112	AF	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.0000			0.5000	0.5000				
113	AF	Acct E301-E303 Intangible Plt	INTANGPLT	40,584,928	1,814,427	1,995,655	9,483,470	7,036,536	490,200	393,380	9,042,004	10,329,255
114	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**										
115	AF											
116	AF	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0	0	0	0	0	0	0	0	0
117	AF	E391-E398 General Plant	GENPLT	429,584,593	20,166,534	22,180,803	100,322,166	78,207,913	0	0	100,497,773	108,209,403
118	AF	Common Plant	COMPLT	126,654,044	1,587,719	1,746,304	11,272,300	6,157,341	72,130,276	17,328,503	7,912,231	8,519,370
119	AF	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	556,238,637	21,754,254	23,927,107	111,594,466	84,365,254	72,130,276	17,328,503	108,410,004	116,728,774
120	AF											

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	AF	Total Plant	TOTPLT	11,456,990,950	512,206,759	563,366,875	2,677,152,347	1,986,390,954	138,381,700	111,050,006	2,552,527,759	2,915,914,551
122	AF											
123	AF	Total Distribution Plant Reserve	TOTDRESERVE	3,099,332,698	126,416,094	252,481,133	742,150,688	455,781,716	84,778,006	49,872,573	577,895,582	809,956,907
124	AF	Total Net Plant	TOTPLTNET	8,357,658,252	385,790,665	310,885,742	1,935,001,659	1,530,609,238	53,603,694	61,177,433	1,974,632,177	2,105,957,644
125	AF											
126	AF											
127	AF	**Revenue Related**										
128	AF	Total Operating Revenue	TOTREV	1,887,985,784	83,986,414	55,787,607	371,121,560	301,389,237	122,125,623	164,440,675	387,005,653	402,129,014
129	AF											
130	AF	**Expense Related**										
131	AF	Distr Oper Exp	DISTEXPO	52,242,807	602,481	4,919	1,264,034	9,451,348	0	18,746,406	11,850,265	10,323,355
132	AF	Distr Maint Exp	DISTEXPM	123,204,777	12,435,991	2,882	22,178,526	28,544,919	0	179,330	36,225,717	23,637,412
133	AF	Cust Serv & Info Expense	CUSTS_I	5,318,001	0	0	2,010,317	0	3,307,684	0	0	0
134	AF	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
135	AF	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	99,712,063	0	0	3,623,918	0	77,475,509	18,612,636	0	0
136	AF	Sales Expense	SALESEXP	40,922	0	0	40,922	0	0	0	0	0
137	AF	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	311,457,637	14,619,870	4,542,993	43,629,616	49,718,221	58,862,615	23,972,325	63,020,218	53,091,779
138	AF	Tot Admin & Genl Exp xPension/Ben	A_GEXP	111,662,106	5,130,402	4,485,186	25,892,473	17,608,596	5,690,820	5,888,111	22,391,031	24,575,487
139	AF	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	94,394,062	0	0	1,613,601	0	74,167,825	18,612,636	0	0
140	AF	O&M + Capital Additions	EXPENDITURES	964,609,657	53,381,629	16,660,642	207,665,037	154,529,550	58,862,615	39,305,922	197,603,720	236,600,542
141	AF											
142	AF	Depreciation Expense (total)	DEPREXP	286,771,855	12,734,767	14,006,738	66,520,119	49,386,749	5,248,426	3,086,796	63,462,355	72,325,904
143	AF											
144	AF	NJ State Income Tax (CBT)	STATEINCTAX	116,400,498	5,239,323	3,964,788	25,555,900	20,069,047	545,393	7,204,848	25,872,953	27,948,245
145	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	1,034,603	49,579	-308	130,323	84,027	325,719	260,875	106,338	78,051
146	AF											
147	AF	**Labor Expense Related**										
148	AF	Total Distribution Exp (Oper) Labor	TLABDO	43,603,802	200,206	2,357	2,292,485	3,769,357	0	27,422,758	4,670,963	5,245,674
149	AF	Total Distribution Exp (Maint) Labor	TLABDM	45,417,214	7,414,246	31,034	9,065,842	9,294,996	0	701,413	11,867,757	7,041,925
150	AF	Total Labor	LABOR	159,006,836	7,614,452	33,391	20,204,791	13,064,353	49,565,467	39,698,060	16,538,721	12,287,599
151	AF											
152	AF	**REVENUES AND BILLING DETERMINANTS**											
153	AF											
154	AF	Base Rate Sales Revenue	SALESREV	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
155	AF											
156	AF	Residential Service	REVRS	817,837,432	0	86,433	180,063,110	139,066,006	70,757,324	127,086,199	133,932,620	166,845,741
157	AF	**ALLOCATION FACTOR TABLE CONTINUED**										
158	AF											
159	AF	Residential Heating Service	REVRHS	4,371,623	0	544,133	585,845	447,756	342,780	441,165	914,735	1,095,209
160	AF	Residential Load Management Service	REVRLM	23,721,865	0	14,754,404	1,939,332	1,528,767	583,211	739,733	1,909,409	2,267,010
161	AF	Water Heating Service	REVWH	34,174,203	0	34,030,901	5,578	0	12,139	113,297	5,723	6,565
162	AF	Water Heating Storage Service	REVWHS	146,591	0	144,405	83	0	186	1,767	70	80
163	AF	Building Heating Service	REVHS	701,978	0	0	129,028	99,066	143,951	75,955	115,870	138,109
164	AF	Body Police Lighting Service	REVBLP	66,086,163	59,591,770	0	28,723	0	512,565	207	2,772,479	3,180,419
165	AF	Body Police Lighting Service from Publicly Owned	REVBLPPOF	730,955	386,296	0	908	0	21,962	11	149,863	171,914
166	AF	Private Street and Area Lighting Service	REVPAL	26,795,398	22,962,497	0	22,568	0	932,125	100	1,340,439	1,537,670
167	AF	General Power and Lighting Service	REVGLP	384,902,021	0	5,443,311	98,013,689	75,139,161	22,903,156	23,638,990	71,325,946	88,437,768
168	AF	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	102,952	76,299,397	61,198,678	14,368,111	6,947,861	102,205,398	118,347,602
169	AF	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	24,942	8,841,568	15,660,204	3,074,816	1,173,602	29,519,937	14,529,350
170	AF	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	43	184,854	4,201,745	4,695,018	1,548,489	37,450,846	112,638
171	AF	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	58,023	0	2,197,961	669,083	0	0
172	AF	HEP	REVHEP	0	0	0	0	0	0	0	0	0
173	AF											
174	AF											
175	AF	Total Rev Req @ desired ROR	REVREQ	1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
176	AF											
177	AF											
178	AF	**PRESENT REVENUES FROM SALES INPUT**										
179	AF											
180	AF	Total Sales of Electricity Revenues		0	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
181	AF	Sales of Electricity Revenues - Rates		1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745	1,254,696,745
182	AF	Sales of Electricity Revenues - Other		0	0	0	0	0	0	0	0	0
183	AF											
184	AF	**RATE OF RETURN**										
185	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	AP	**ALLOCATION PROPORTIONS TABLE**										
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
3	AP											
4	AP	**ALLOCATION FACTORS PART A**										
5	AP											
6	AP	CP @ secondary lines - local	CP_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
7	AP	Number of Customers x Aux &SL rates - local	CUSTNUMX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
8	AP											
9	AP											
10	AP	CP @ 26 kV lines - switching station load -systems	CP_SUBT_05	1.000000				1.000000				
11	AP	CP @ primary lines - systems	CP_PRI_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Sum Cust Peaks @ 26 kV lines - local	SUMPK_SUBT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AP	Sum Cust Peaks @ primary lines - local	SUMPK_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AP	Sum Cust Peaks @ secondary lines - local	SUMPK_SEC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
15	AP	CP @ primary lines - local	CP_PRI_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
16	AP	NCP @ meter - local	NCP_MTR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
17	AP	NCP @ meter - measurement	NCP_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
18	AP	NCP @ meter - cust svs	NCP_MTR_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
19	AP	NCP x SL rates @ meter - measurement	NCPXSL_MTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
20	AP	**BILLING DETERMINANTS**										
21	AP											
22	AP	Number of Customers										
23	AP	Delivered kWh @ Meter - annual (w/n net)										
24	AP	Delivered Kw @ Meter - annual										
25	AP											
26	AP	**ALLOCATION FACTORS PART B**										
27	AP											
28	AP	Delivery kWh @ meter	KWHMETER_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
29	AP	Delivery kWh @ meter x non-profiled rates	KWHMETERX_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
30	AP											
31	AP	Delivery kWh @ subtrans - System E	KWH_SUBT_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
32	AP	Delivery kWh @ primary - System E	KWH_PRI_09	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
33	AP	Delivery kWh @ primary - Local E	KWH_PRI_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
34	AP	Delivery kWh @ secondary - Local E	KWH_SEC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
35	AP	Delivery kWh @ meter - measurement	KWHMETER_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
36	AP	Delivery kWh @ meter - cust svs	KWHMETER_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
37	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
38	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
39	AP											
40	AP	**ALLOCATION FACTORS PART C**										
41	AP											
42	AP	Avg Customer Bills - measurement	CUSTAVG_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
43	AP	E370 excess meter investment - local delivery - Demand	METERSEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	E370 excess meter investment - local delivery - Energy	METERSEXC_10	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
45	AP	Meter O&M - measurement	METERPLT_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
46	AP	E370 excess mtr invst - measrmnt	METERSEXC_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
47	AP	E587 Customer Installation Expenses Local	CUSINT_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	AP	E587 Customer Installation Expenses System	CUSINT_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
49	AP	Draft EC Proforma	ECPRO_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
50	AP	Expense Reclassification-local	ADJEXP_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
51	AP	Expense Reclassification Plus-local	ADJ_Plus_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	E369 minimum Service investment- access	SERVICESMIN_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	E369 excess Service investment- local delivery	SERVICESEXC_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Avg Customer Bills - local	CUSTAVG_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
56	AP	E370 minimum meter investment - measurement	METERSMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
57	AP	E368 Line Transfomers - local	LNTRFRMR_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
58	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
59	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
60	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	AP	Sales	SALES_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
62	AP	Other Utility work by Cust Ops - local	UTILWORK_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
63	AP											
64	AP	Choice - local	CHOICE_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP											
66	AP	Direct - PSAL - streetlighting	DIR_PSAL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
67	AP	Direct - BPL - streetlighting	DIR_BPL_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
68	AP	Direct - BPL-POF - streetlighting	DIR_BPLPOF_02	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
69	AP	Direct - HTS-HV - access	DIR_HTSHV_03	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
70	AP	Direct - HEP - access	DIR_HEP_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
71	AP	Direct - HTS-Sub - systems	DIR_HTSS_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
72	AP											
73	AP	Direct - HTS-Sub - local	DIR_HTSS_04	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
74	AP	Meter O&M - minimum - measurement	MTROMMIN_07	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
75	AP	Meter O&M - excess - measurement	MTROMEXC_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
76	AP	WN TEFA Responsibility	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
77	AP											
78	AP	E370 excess meter investment - dummy	METERSEXC_08	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Meter O&M - excess - dummy	MTROMEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	E369 excess Service investment- dummy	SERVICESEXC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
81	AP	E368 Line Transfomers - dummy	LNTRFRMR_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
82	AP	CP @ 26 kV lines - switching station load - dummy	CP@SUBT_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
83	AP	CP @ primary lines - dummy	CP@PRI_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
84	AP	Sum Cust Peaks @ secondary lines - local	SUMPK@SEC_08	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
85	AP											
86	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
87	AP	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
88	AP											
89	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
90	AP											
91	AP	**Plant Related**										
92	AP	Distribution Plant Total	DISTPLT	1.000000	0.045352	0.049882	0.236952	0.175880	0.000000	0.007084	0.226007	0.258843
93	AP	Distribution Plant x meters	DISTPLTXMTR	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000	0.233942	0.251893
94	AP	Acct E360 - Land & Land Rights	E360PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
95	AP	Acct E361 - Structures & Improvments	E361PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
96	AP	Acct E362 - Station Equipment	E362PLT	1.000000	0.000000	0.000000	0.000000	0.427859	0.000000	0.000000	0.572141	0.000000
97	AP	Acct E364 - Poles & Towers	E364PLT	1.000000	0.009662	0.000000	0.315474	0.135058	0.000000	0.000000	0.198438	0.341367
98	AP	Acct E365 - OH Conductors & Devices x HTSHV	E365PLT	1.000000	0.003033	0.000000	0.236711	0.230718	0.000000	0.000000	0.281673	0.247865
99	AP	Acct E366 - UG Conduit	E366PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000	0.172561	0.352708
100	AP	Acct E367 - UG Conductors & Devices x HEP	E367PLT	1.000000	0.002362	0.000144	0.327035	0.145191	0.000000	0.000000	0.172561	0.352708
101	AP	Acct E369 Services	E369PLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
102	AP	Acct E370 Meters	METERPLT	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846	0.000000	0.456806
103	AP	Acct E370 Meters x load profile meters	METERPLTXPR	1.000000	0.000000	0.000000	0.334347	0.000000	0.000000	0.208846	0.000000	0.456806
104	AP	Acct E373 - Streetlights	E373PLT	1.000000	0.930815	0.003748	0.016953	0.013216	0.000000	0.000000	0.016983	0.018286
105	AP	Subtrans Lines - HTS-S/Switching Station load	SUBTRANSLINES	1.000000	0.000000	0.000000	0.211000	0.789000	0.000000	0.000000	0.000000	0.000000
106	AP	Primary Lines - 50 Sys CP/50 Loc Sum Cust Pks	PRIMARYLINES	1.000000	0.000000	0.000000	0.500000	0.500000	0.000000	0.000000	0.000000	0.000000
107	AP											
108	AP	Acct E301-E303 Intangible Plt	INTANGPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693	0.222792	0.254510
109	AP	Acct E399.10-23 Oth Tangible Plt	TANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
110	AP	E391-E398 General Plant	GENPLT	1.000000	0.046944	0.051633	0.233533	0.182055	0.000000	0.000000	0.233942	0.251893
111	AP	Common Plant	COMPLT	1.000000	0.012536	0.013788	0.089001	0.048615	0.569506	0.136818	0.062471	0.067265
112	AP	Accts C389-C399, E389-E399 Com & Gen Plt	COMGENPLT	1.000000	0.039110	0.043016	0.200623	0.151671	0.129675	0.031153	0.194898	0.209854
113	AP											
114	AP	Total Plant	TOTPLT	1.000000	0.044707	0.049172	0.233670	0.173378	0.012078	0.009693	0.222792	0.254510
115	AP											
116	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.040788	0.081463	0.239455	0.147058	0.027354	0.016091	0.186458	0.261333
117	AP	Total Net Plant	TOTPLTNET	1.000000	0.046160	0.037198	0.231524	0.183139	0.006414	0.007320	0.236266	0.251979
118	AP											
119	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
120	AP	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
121	AP											
122	AP	**Revenue Related**										
123	AP	Total Operating Revenue	TOTREV	1.000000	0.044485	0.029549	0.196570	0.159635	0.064686	0.087098	0.204983	0.212994
124	AP											
125	AP	**Expense Related**		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.011532	0.000094	0.024195	0.180912	0.000000	0.358832	0.226831	0.197603
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.100938	0.000023	0.180014	0.231687	0.000000	0.001456	0.294029	0.191855
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.000000	0.378021	0.000000	0.621979	0.000000	0.000000	0.000000
129	AP	Acct E901-E903,E905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180	0.000000	0.000000
130	AP	Accts E901-E910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.000000	0.036344	0.000000	0.776992	0.186664	0.000000	0.000000
131	AP	Sales Expense	SALESEXP	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
132	AP	Total O&M Expense Excl 904-Uncollectibles	TOTOMXAG	1.000000	0.046940	0.014586	0.140082	0.159631	0.188991	0.076968	0.202340	0.170462
133	AP	Tot Admin & Genl Exp xPension/Ben	A_GEXP	1.000000	0.045946	0.040167	0.231882	0.157695	0.050965	0.052732	0.200525	0.220088
134	AP	Accts E901-E905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.000000	0.017094	0.000000	0.785726	0.197180	0.000000	0.000000
135	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.055340	0.017272	0.215284	0.160199	0.061022	0.040748	0.204854	0.245281
136	AP											
137	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.044407	0.048843	0.231962	0.172216	0.018302	0.010764	0.221299	0.252207
138	AP											
139	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.045011	0.034062	0.219551	0.172414	0.004685	0.061897	0.222275	0.240104
140	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.047921	-0.000297	0.125964	0.081217	0.314825	0.252150	0.102782	0.075440
141	AP											
142	AP	**Labor Expense Related**										
143	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.004591	0.000054	0.052575	0.086446	0.000000	0.628908	0.107123	0.120303
144	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.163247	0.000683	0.199612	0.204658	0.000000	0.015444	0.261305	0.155050
145	AP	Total Labor	LABOR	1.000000	0.047888	0.000210	0.127069	0.082162	0.311719	0.249663	0.104013	0.077277
146	AP											
147	AP	REVENUES AND BILLING DETERMINANTS										
148	AP											
149	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.044523	0.029595	0.196563	0.159614	0.064709	0.087196	0.204867	0.212934
150	AP											
151	AP	Residential Service	REVRS	1.000000	0.000000	0.000106	0.220170	0.170041	0.086518	0.155393	0.163764	0.204008
152	AP	Residential Heating Service	REVRHS	1.000000	0.000000	0.124469	0.134011	0.102423	0.078410	0.100916	0.209244	0.250527
153	AP	Residential Load Management Service	REVRLM	1.000000	0.000000	0.621975	0.081753	0.064445	0.024585	0.031184	0.080492	0.095566
154	AP	Water Heating Service	REVWH	1.000000	0.000000	0.995807	0.000163	0.000000	0.000355	0.003315	0.000167	0.000192
155	AP	Water Heating Storage Service	REVWHS	1.000000	0.000000	0.985085	0.000569	0.000000	0.001269	0.012051	0.000477	0.000548
156	AP	Building Heating Service	REVHS	1.000000	0.000000	0.000000	0.183806	0.141124	0.205065	0.108201	0.165062	0.196742
157	AP	Body Police Lighting Service	REVBLP	1.000000	0.901728	0.000000	0.000435	0.000000	0.007756	0.000003	0.041952	0.048125
158	AP	Body Police Lighting Service from Publicly Owned	REVBLPPOF	1.000000	0.528481	0.000000	0.001242	0.000000	0.030046	0.000015	0.205024	0.235191
159	AP	Private Street and Area Lighting Service	REVPAL	1.000000	0.856957	0.000000	0.000842	0.000000	0.034787	0.000004	0.050025	0.057386
160	AP	General Power and Lighting Service	REVGLP	1.000000	0.000000	0.014142	0.254646	0.195216	0.059504	0.061416	0.185309	0.229767
161	AP	Large Power and Lighting Service - Secondary	REVLPLS	1.000000	0.000000	0.000271	0.201068	0.161274	0.037864	0.018309	0.269337	0.311876
162	AP	Large Power and Lighting Service - Primary	REVLPLP	1.000000	0.000000	0.000342	0.121409	0.215041	0.042222	0.016115	0.405358	0.199512
163	AP	High Tension Service - Subtransmission	REVHTSS	1.000000	0.000000	0.000001	0.003836	0.087185	0.097420	0.032131	0.777091	0.002337
164	AP	High Tension Service - High Voltage	REVHTSHV	1.000000	0.000000	0.000000	0.019836	0.000000	0.751423	0.228741	0.000000	0.000000
165	AP	HEP	REVHEP	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
166	AP											
167	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.044523	0.029595	0.196563	0.159614	0.064709	0.087196	0.204867	0.212934
168	AP											
169	AP	**PRESENT REVENUES FROM SALES INPUT**										
170	AP											
171	AP	Total Sales of Electricity Revenues		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
172	AP	Sales of Electricity Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
173	AP	Sales of Electricity Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**										
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**										
3	ADA											
4	ADA	**Net Write-Offs**										
5	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
6	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
7	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
8	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
9	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
10	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0	0
11	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
12	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
13	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0	0
14	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0	0
15	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0	0
16	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0	0
17	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0	0
18	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0	0
19	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
20	ADA											
21	ADA	Total Write-Offs	EXP_904	0	0	0	0	0	0	0	0	0
22	ADA											
23	ADA	Total Write-Offs	EXP_904									
24	ADA											
25	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0	0
26	ADA											
27	ADA											
28	ADA	**Rev to Customers w/Late Payment fees**										
29	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
30	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
31	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
32	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
33	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
34	ADA	Building Heating Service	REVHS	701,978	0	0	129,028	99,066	143,951	75,955	115,870	138,109
35	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
36	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
37	ADA	Private Street and Area Lighting Service	REVPAL	26,795,398	22,962,497	0	22,568	0	932,125	100	1,340,439	1,537,670
38	ADA	General Power and Lighting Service	REVGLP	384,902,021	0	5,443,311	98,013,689	75,139,161	22,903,156	23,638,990	71,325,946	88,437,768
39	ADA	Large Power and Lighting Service - Secondary	REVLPLS	379,469,998	0	102,952	76,299,397	61,198,678	14,368,111	6,947,861	102,205,398	118,347,602
40	ADA	Large Power and Lighting Service - Primary	REVLPLP	72,824,417	0	24,942	8,841,568	15,660,204	3,074,816	1,173,602	29,519,937	14,529,350
41	ADA	High Tension Service - Subtransmission	REVHTSS	48,193,633	0	43	184,854	4,201,745	4,695,018	1,548,489	37,450,846	112,638
42	ADA	High Tension Service - High Voltage	REVHTSHV	2,925,067	0	0	58,023	0	2,197,961	669,083	0	0
43	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
44	ADA											
45	ADA	Total Late Payment Fees	REVLATEP	915,812,512	22,962,497	5,571,247	183,549,126	156,298,854	48,315,137	34,054,078	241,958,435	223,103,137
46	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.025073	0.006083	0.200422	0.170667	0.052757	0.037185	0.264201	0.243612
47	ADA											
48	ADA	**ALLOCATED DIRECT ASSIGNMENTS**										
49	ADA	DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS										
50	ADA											
51	ADA	**AVAILABLE**										
52	ADA	Residential Service	REVRS	0	0	0	0	0	0	0	0	0
53	ADA	Residential Heating Service	REVRHS	0	0	0	0	0	0	0	0	0
54	ADA	Residential Load Management Service	REVRLM	0	0	0	0	0	0	0	0	0
55	ADA	Water Heating Service	REVWH	0	0	0	0	0	0	0	0	0
56	ADA	Water Heating Storage Service	REVWHS	0	0	0	0	0	0	0	0	0
57	ADA	Building Heating Service	REVHS	0	0	0	0	0	0	0	0	0
58	ADA	Body Police Lighting Service	REVBLP	0	0	0	0	0	0	0	0	0
59	ADA	Body Police Lighting Service from Publicly Owned	REVBLPPOF	0	0	0	0	0	0	0	0	0
60	ADA	Private Street and Area Lighting Service	REVPAL	0	0	0	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
61	ADA	General Power and Lighting Service	REVGLP	0	0	0	0	0	0	0	0	0
62	ADA	Large Power and Lighting Service - Secondary	REVLPLS	0	0	0	0	0	0	0	0	0
63	ADA	Large Power and Lighting Service - Primary	REVLPLP	0	0	0	0	0	0	0	0	0
64	ADA	High Tension Service - Subtransmission	REVHTSS	0	0	0	0	0	0	0	0	0
65	ADA	High Tension Service - High Voltage	REVHTSHV	0	0	0	0	0	0	0	0	0
66	ADA	HEP	REVHEP	0	0	0	0	0	0	0	0	0
67	ADA											
68	ADA	Total Available	REVAVAIL	0	0	0	0	0	0	0	0	0
69	ADA	Total Available	REVAVAIL									

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 STAFF ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Street Lighting	Access	Local Delivery Demand	System Delivery Demand	Customer Service	Measurement	System Delivery Energy	Local Delivery Energy
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RRW	**REVENUE REQUIREMENTS**										
2	RRW											
3	RRW	PRESENT RATES										
4	RRW	----------										
5	RRW	RATE BASE		9,635,540,505	428,006,101	303,548,316	2,062,243,696	1,626,936,215	91,388,048	766,643,982	2,097,950,132	2,258,824,013
6	RRW	NET OPER INC (PRESENT RATES)		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
10	RRW	REVENUE PRES RATES $/KWH		$0.0456	$0.0020	$0.0014	$0.0090	$0.0073	$0.0030	$0.0040	$0.0094	$0.0097
11	RRW	REVENUE REQUIRED - $/MO/CUST		$66.11	$2.94	$1.96	$12.99	$10.55	$4.28	$5.76	$13.54	$14.08
12	RRW	SALES REV REQUIRED $/KW										
13	RRW											
14	RRW	CLAIMED RATE OF RETURN										
15	RRW	----------										
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		711,102,889	31,586,850	22,401,866	152,193,585	120,067,893	6,744,438	56,578,326	154,828,720	166,701,212
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,862,881,345	82,940,563	55,131,523	366,172,706	297,341,383	120,545,304	162,436,456	381,643,335	396,670,076
19	RRW	REVENUE DEFICIENCY SALES REV						0		(0)	0	
20	RRW	PERCENT INCREASE REQUIRED										
21	RRW	ANNUAL BOOKED KWH SALES		40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564	40,816,033,564
22	RRW	SALES REV REQUIRED $/KWH		$0.0456	$0.0020	$0.0014	$0.0090	$0.0073	$0.0030	$0.0040	$0.0094	$0.0097
23	RRW	REVENUE DEFICIENCY $/KWH										

Functional Cost Summary
2022 STAFF ELECTRIC COST OF SERVICE STUDY
Updated for 5 and 7

EXHIBIT P-9E
Schedule SS-E15

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RS	RHS	RLM	WH	WHS	HS	BPL
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Street Lighting	$82,940,563	0	0	0	0	0	0	$59,591,770
2	Access	$55,131,523	$86,433	$544,133	$14,754,404	$34,030,901	$144,405	0	0
3	Local Delivery Demand	$366,172,706	$180,063,110	$585,845	$1,939,332	$5,578	$83	$129,028	$28,723
4	Local Delivery Energy	$396,670,076	$166,845,741	$1,095,209	$2,267,010	$6,565	$80	$138,109	$3,180,419
5	System Delivery Demand	$297,341,383	$139,066,006	$447,756	$1,528,767	0	0	$99,066	0
6	System Delivery Energy	$381,643,335	$133,932,620	$914,735	$1,909,409	$5,723	$70	$115,870	$2,772,479
7	Customer Service	$120,545,304	$70,757,324	$342,780	$583,211	$12,139	$186	$143,951	$512,565
8	Measurement	162,436,456	127,086,199	441,165	739,733	113,297	1,767	75,955	207
9	Total	$1,862,881,345	$817,837,432	$4,371,623	$23,721,865	$34,174,203	$146,591	$701,978	$66,086,163

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 ELECTRIC COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	BPL-POF (9)	PSAL (10)	GLP (11)	LPL-Secondary (12)	LPL-Primary (13)	HTS-Subtransmission (14)	HTS-High Voltage (15)
1	Street Lighting	$386,296	$22,962,497	0	0	0	0	0
2	Access	0	0	$5,443,311	$102,952	$24,942	$43	0
3	Local Delivery Demand	$908	$22,568	$98,013,689	$76,299,397	$8,841,568	$184,854	$58,023
4	Local Delivery Energy	$171,914	$1,537,670	$88,437,768	$118,347,602	$14,529,350	$112,638	0
5	System Delivery Demand	0	0	$75,139,161	$61,198,678	$15,660,204	$4,201,745	0
6	System Delivery Energy	$149,863	$1,340,439	$71,325,946	$102,205,398	$29,519,937	$37,450,846	0
7	Customer Service	$21,962	$932,125	$22,903,156	$14,368,111	$3,074,816	$4,695,018	$2,197,961
8	Measurement	11	100	23,638,990	6,947,861	1,173,602	1,548,489	669,083
9	Total	$730,955	$26,795,398	$384,902,021	$379,469,998	$72,824,417	$48,193,633	$2,925,067

Service Charge Calculations

Service charges are comprised of revenue requirements for the Distribution Access and Measurement segments related to Minimum Size Facilities, plus the Revenue Requirements for the Customer Service segment.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Average Distribution Increase =		41.842%							
line #	Rate Schedule	Access Segment Revenue Requirement From Synced COS Study	Measurement Segment Revenue Requirement From Synced COS Study	Customer Service Segment Revenue Requirements From Synced COS Study	Rev Req to be recovered through Service Charge	# of Customers	Cost Based Monthly Service Charge	Current Monthly Service Charge ($/month)	Proposed Limited Monthly Service Charge	
2	RS	$ 50,821,825	$ 53,086,359	$ 79,920,982	$ 183,829,165	1,981,089	$ 7.73	$ 4.64	$ 7.55	see Note 1
3	RHS	$ 266,449	$ 321,696	$ 621,521	$ 1,209,665	6,404	$ 15.74	$ 4.64	$ 7.55	see Note 1
4	RLM	$ 350,874	$ 438,751	$ 821,245	$ 1,610,869	11,197	$ 11.99	$ 13.07	$ 13.07	see Note 2
5	WH	no service charge								
6	WHS	$ 32	$ 1,459	$ 535	$ 2,027	11	$ 15.71	$ 0.63	$ 1.03	see Note 2
7	HS	$ -	$ 32,965	$ 71,307	$ 104,272	714	$ 12.17	$ 3.75	$ 6.10	see Note 2
8	BPL	no service charge								
9	BPL-POF	no service charge								
10	PSAL	no service charge								
11	GLP	$ 12,677,035	$ 16,379,708	$ 23,203,673		272,921				
12	GLP Metered					256,116	$ 16.42	$ 4.78	$ 7.78	see Note 3
13	GLP Unmetered					5,766	$ 8.87	$ 2.20	$ 3.58	see Note 4
14	GLP-NU					64			$ 347.77	set equal to LPL-S
15	LPL-S	$ 1,176,099	$ 14,248,015	$ 15,874,355	$ 31,298,469	9,379	$ 278.08	$ 347.77	$ 347.77	see Note 2
16	LPL-P	$ 238,299	$ 2,232,543	$ 3,553,274	$ 6,024,116	770	$ 652.02	$ 347.77	$ 566.04	see Note 2
17	LPL-P <100 kW						$ 393.46	$ 21.58	$ 35.12	see Note 5
18	HTS-S	$ 61,237	$ 2,177,125	$ 4,487,900	$ 6,726,262	189	$ 2,959.36	$ 1,911.39	$ 2,959.36	see Note 2
19	HTS-HV	$ -	$ 169,708	$ 296,291	$ 465,998	16	$ 2,379.87	$ 1,720.25	$ 2,379.87	see Note 2
Source:					= (2) + (3) + (4)		= (5) / (6) / 12	From Tariff		

Notes: 1 Move Toward Cost limited at no decrease from current service charge and no increase greater than 1.5 times the overall average distribution % increase.

2 Access and Customer Service Rev Req per total GLP Customer plus Measurement Rev Req divided by the number of metered customers divided by 12; limits the same as Note 1

3 Access and Customer Service Rev Req per total GLP Customer divided by 12; limits the same as Note 1

4 Calculated at the GLP Access Segment per customer plus the GLP Customer Service Segment Revenue Requirements per customer plus the LPL-P Measurement Segment per customer divided by 12; limits the same as Note 1

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Proposed Rate Calculations

Actual results through: 10/31/2023

Schedule SS-TAC-1

($'s Unless Specified)

SUT Rate 6.625%

Line	Date(s)		Electric	Gas	Total	Source/Description
1	Sept24 - Dec25	Net Revenue Requirements	(188,652,303)	(256,978,518)	(445,630,821)	SS-2E/G, Col 26
2	Aug-24	(Over) / Under Recovered Balance	353,224	(13,018,165)	(12,664,941)	- SS-3E/G, Col 5
3	Aug-24	Cumulative Interest Exp / (Credit)	74,869	(136,068)	(61,199)	- SS-3E/G, Col 10
4	Sept24 - Dec25	Total Target Rate Revenue	(188,224,210)	(270,132,751)	(458,356,961)	ln 1 + ln 2 + ln 3
5	Sept24 - Dec25	Revenue at Proposed 2024 TAC rates	(45,101,391)	(122,531,548)	(167,632,940)	SS-6E/G, ln 19
6	Sept24 - Dec25	Proposed TAC Increase / (Decrease)	(143,122,819)	(147,601,203)	(290,724,022)	Ln 4 - ln 5
7	Sep24 - Aug25	Annualized Target Rate Revenue	(142,860,375)	(211,473,051)	(354,333,426)	SS-6E/G, ln 15
8	Sep24 - Aug25	Annualized Revenue at Proposed 2024 TAC rates	(34,225,047)	(95,774,969)	(130,000,016)	SS-6E/G, ln 17
9	Sep24 - Aug25	Annualized TAC Increase / (Decrease)	(108,635,328)	(115,698,082)	(224,333,410)	Ln 7 - ln 8

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Electric Net Revenue Requirement

$000

	1	2	3	4	5	6	7	8	9	10	11	12
	1. Return Historic ADIT											
	Unprotected Excess			**Protected Excess**			**SHARE**			**Mixed Service Cost**		
	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance
Jan-23	71,138	(5,297)	65,841	351,198	(847)	350,351	95,414	(702)	94,713	-	-	-
Feb-23	65,841	(5,297)	60,543	350,351	(847)	349,504	94,713	(702)	94,011	-	-	-
Mar-23	60,543	(10,137)	50,407	349,504	(1,516)	347,988	94,011	(1,342)	92,669	-	-	-
Apr-23	50,407	(3,694)	46,713	347,988	(572)	347,416	92,669	(489)	92,179	-	-	-
May-23	46,713	(3,440)	43,273	347,416	(533)	346,883	92,179	(456)	91,724	-	-	-
Jun-23	43,273	(5,387)	37,886	346,883	(834)	346,049	91,724	(713)	91,010	-	-	-
Jul-23	37,886	(6,847)	31,039	346,049	(1,060)	344,988	91,010	(907)	90,104	-	-	-
Aug-23	31,039	(6,091)	24,948	344,988	(943)	344,045	90,104	(807)	89,297	-	-	-
Sep-23	24,948	(3,328)	21,620	344,045	(515)	343,530	89,297	(441)	88,856	-	-	-
Oct-23	21,620	(3,737)	17,883	343,530	(579)	342,951	88,856	(495)	88,361	-	-	-
Nov-23	17,883	(4,985)	12,898	342,951	(772)	342,179	88,361	(660)	87,701	-	-	-
Dec-23	12,898	(5,329)	7,569	342,179	(825)	341,354	87,701	(706)	86,995	-	-	-
Jan-24	7,569	(1,014)	6,555	341,354	(1,363)	339,991	86,995	(2,332)	84,664	-	-	-
Feb-24	6,555	(778)	5,777	339,991	(1,046)	338,945	84,664	(1,789)	82,875	-	-	-
Mar-24	5,777	(676)	5,101	338,945	(908)	338,037	82,875	(1,554)	81,321	-	-	-
Apr-24	5,101	(440)	4,661	338,037	(591)	337,446	81,321	(1,011)	80,310	-	-	-
May-24	4,661	(410)	4,251	337,446	(550)	336,896	80,310	(941)	79,369	-	-	-
Jun-24	4,251	(641)	3,610	336,896	(862)	336,035	79,369	(1,474)	77,894	-	-	-
Jul-24	3,610	(815)	2,795	336,035	(1,095)	334,939	77,894	(1,874)	76,020	-	-	-
Aug-24	2,795	(725)	2,069	334,939	(974)	333,965	76,020	(1,667)	74,353	-	-	-
Sep-24	2,069	(396)	1,673	333,965	(532)	333,433	74,353	(911)	73,442	-	-	-
Oct-24	1,673	(445)	1,228	333,433	(598)	332,835	73,442	(1,023)	72,419	-	-	-
Nov-24	1,228	(594)	635	332,835	(797)	332,037	72,419	(1,364)	71,055	-	-	-
Dec-24	635	(635)	0	332,037	(852)	331,185	71,055	(1,459)	69,596	-	-	193,961
Jan-25	0	-	0	331,185	(967)	330,218	69,596	(2,332)	67,265	193,961	(9,381)	184,580
Feb-25	0	-	0	330,218	(742)	329,477	67,265	(1,789)	65,476	184,580	(7,198)	177,383
Mar-25	0	-	0	329,477	(644)	328,832	65,476	(1,554)	63,922	177,383	(6,250)	171,132
Apr-25	0	-	0	328,832	(419)	328,413	63,922	(1,011)	62,911	171,132	(4,068)	167,065
May-25	0	-	0	328,413	(390)	328,023	62,911	(941)	61,970	167,065	(3,788)	163,277
Jun-25	0	-	0	328,023	(611)	327,412	61,970	(1,474)	60,495	163,277	(5,932)	157,346
Jul-25	0	-	0	327,412	(777)	326,635	60,495	(1,874)	58,621	157,346	(7,540)	149,805
Aug-25	0	-	0	326,635	(691)	325,943	58,621	(1,667)	56,954	149,805	(6,708)	143,098
Sep-25	0	-	0	325,943	(378)	325,566	56,954	(911)	56,043	143,098	(3,665)	139,433
Oct-25	0	-	0	325,566	(424)	325,142	56,043	(1,023)	55,020	139,433	(4,115)	135,319
Nov-25	0	-	0	325,142	(566)	324,576	55,020	(1,364)	53,656	135,319	(5,489)	129,829
Dec-25	0	-	0	324,576	(605)	323,971	53,656	(1,459)	52,197	129,829	(5,868)	123,961
	= Prev Col 3 + Col 1 & 2 of "Balances" Wkst	Input	= Col 1 + Col 2	= Prev Col 6 + Col 3 of "Balances" Wkst	Input	= Col 4 + Col 5	= Prev Col 9 + Col 4 of "Balances" Wkst	Input	= Col 7 + Col 8	= Prev Col 12 + Col 5 of "Balances" Wkst	Input	= Col 10 + Col 11
Annual												
2023		(63,569)			(9,845)			(8,419)			-	
2024		(7,569)			(10,169)			(17,399)			-	
2025		-			(7,214)			(17,399)			(70,000)	
2026		-			(5,958)			(17,399)			(45,000)	
2027		-			(6,259)			(17,399)			(33,000)	
2028		-			(6,119)			(17,399)			(20,000)	
2029		-			(5,116)			(17,399)			(25,961)	

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Electric Net Revenue Requirement

$000

Exhibit P-9E

Schedule SS-TAC-2E

	Monthly After Tax WACC Post -2023 BRC:	0.587%		Monthly After Tax WACC Post -2023 BRC:	0.587%								Revenue Factor =	1.3947
	Monthly After Tax WACC Pre-2023 BRC:	0.540%		Monthly After Tax WACC Pre-2023 BRC:	0.540%	Fed Tax Rate =	21.00%							
13	14	15	16	17	18	19	20	21	22	23	24	25	26	
	1. Return Historic ADIT (cont.)			**1a. Return Historic ADIT (cont.)**				**2. Current ESHARE Deduciton**	**2a. Current Mixed Srv & IDD**	**3. Other**				
	Return on Rate Base			**Return on Non Rate Base**										
	Unprotected Excess ADIT Rate Base Related %	Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Non-Rate Base Related Portion of Unprotected Excess	Non-Rate Base Related Portion of Unprotected Excess ADIT Amortizaiton to Customers	Ending Non-Rate Base Related Portion of Unprotected Excess	After-Tax Interest to Customers	Actual SHARE Deduction Flow-Through	Actual Mixed Service Cost Deduction Flow-Through	IRS ESHARE Deduction Audit Adjustments	Other Major Tax Adjustments	Net Tax Adjustment	**Net Revenue Requirement**
Jan-23	78%	(4,135)	247,378	1,302	13,947	(1,162)	12,785	(72)	(1,150)	-	-	-	(6,766)	**(9,437)**
Feb-23	78%	(4,135)	252,928	1,351	12,785	(1,162)	11,623	(66)	(1,150)	-	-	-	(6,711)	**(9,359)**
Mar-23	78%	(7,913)	258,344	1,381	11,623	(2,224)	9,399	(57)	(2,393)	-	-	(3)	(14,067)	**(19,619)**
Apr-23	78%	(2,883)	263,734	1,410	9,399	(810)	8,588	(49)	(836)	-	-	(5)	(4,234)	**(5,906)**
May-23	78%	(2,685)	269,054	1,439	8,588	(755)	7,834	(44)	(779)	-	-	(3)	(3,814)	**(5,320)**
Jun-23	78%	(4,205)	274,306	1,468	7,834	(1,182)	6,652	(39)	(1,219)	-	-	(2)	(6,727)	**(9,382)**
Jul-23	78%	(5,345)	279,489	1,496	6,652	(1,502)	5,149	(32)	(1,550)	-	-	(3)	(8,903)	**(12,417)**
Aug-23	78%	(4,755)	284,602	1,524	5,149	(1,336)	3,813	(24)	(1,379)	-	-	(4)	(7,725)	**(10,774)**
Sep-23	78%	(2,598)	289,648	1,551	3,813	(730)	3,083	(19)	(753)	-	-	(3)	(3,508)	**(4,893)**
Oct-23	78%	(2,917)	294,624	1,578	3,083	(820)	2,263	(14)	(846)	-	-	(1)	(4,093)	**(5,709)**
Nov-23	78%	(3,891)	299,533	1,605	2,263	(1,094)	1,169	(9)	(1,128)	-	-	(0)	(5,950)	**(8,299)**
Dec-23	78%	(4,160)	304,372	1,631	1,169	(1,169)	-	(3)	(1,206)	-	-	0	(6,438)	**(8,979)**
Jan-24	100%	(1,014)	312,508	1,666	-	-	-	-	(2,095)	-	-	-	(5,138)	**(7,166)**
Feb-24	100%	(778)	315,299	1,696	-	-	-	-	(1,608)	-	-	-	(3,525)	**(4,916)**
Mar-24	100%	(676)	318,019	1,711	-	-	-	-	(1,396)	-	-	-	(2,823)	**(3,937)**
Apr-24	100%	(440)	320,669	1,725	-	-	-	-	(909)	-	-	-	(1,225)	**(1,709)**
May-24	100%	(410)	323,248	1,739	-	-	-	-	(846)	-	-	-	(1,008)	**(1,406)**
Jun-24	100%	(641)	325,757	1,753	-	-	-	-	(1,325)	-	-	-	(2,549)	**(3,556)**
Jul-24	100%	(815)	328,194	1,766	-	-	-	-	(1,684)	-	-	-	(3,703)	**(5,164)**
Aug-24	100%	(725)	330,560	1,779	-	-	-	-	(1,498)	-	-	-	(3,086)	**(4,304)**
Sep-24	100%	(396)	8,538	996	-	-	-	-	(819)	-	-	-	(1,662)	**(2,318)**
Oct-24	100%	(445)	10,762	57	-	-	-	-	(919)	-	-	-	(2,928)	**(4,083)**
Nov-24	100%	(594)	12,917	70	-	-	-	-	(1,226)	-	-	-	(3,912)	**(5,456)**
Dec-24	100%	(635)	15,000	82	-	-	-	-	(1,311)	-	-	-	(4,174)	**(5,822)**
Jan-25	0.0%	-	33,096	141	-	-	-	-	(1,876)	(1,206)	-	-	(15,620)	**(21,786)**
Feb-25	0%	-	42,707	223	-	-	-	-	(1,440)	(925)	-	-	(11,871)	**(16,556)**
Mar-25	0%	-	50,998	275	-	-	-	-	(1,250)	(804)	-	-	(10,226)	**(14,263)**
Apr-25	0%	-	56,359	315	-	-	-	-	(814)	(523)	-	-	(6,519)	**(9,092)**
May-25	0%	-	61,318	346	-	-	-	-	(758)	(487)	-	-	(6,018)	**(8,393)**
Jun-25	0%	-	69,033	383	-	-	-	-	(1,186)	(763)	-	-	(9,583)	**(13,366)**
Jul-25	0%	-	78,775	434	-	-	-	-	(1,508)	(969)	-	-	(12,234)	**(17,063)**
Aug-25	0%	-	87,383	488	-	-	-	-	(1,342)	(862)	-	-	(10,782)	**(15,037)**
Sep-25	0%	-	92,055	527	-	-	-	-	(733)	(471)	-	-	(5,630)	**(7,853)**
Oct-25	0%	-	97,264	556	-	-	-	-	(823)	(529)	-	-	(6,357)	**(8,866)**
Nov-25	0%	-	104,168	592	-	-	-	-	(1,098)	(706)	-	-	(8,632)	**(12,038)**
Dec-25	0%	-	111,496	633	-	-	-	-	(1,174)	(754)	-	-	(9,226)	**(12,868)**
	= Col 14 / Col 2	Input	See "RateBase-E", Col 9	= (Prev Col 15 + Col 15) / 2 * Monthly AT WACC	Previous Col 19 + Col 1 of "Balances" Wkst	Input	= (Prev Col 17 - Col 18)	= (Prev Col 19 + Col 19) / 2 * Monthly AT WACC	= - (Col 21) * Fed Tax Rate	= - (Col 22) * Fed Tax Rate	Input	Input	= Col 2 + Col 5 + Col 8 + Col 11 + Col 16 + Col 20+ Col 21+ Col 22 + Col 24	= Col 25 * Rev Fct
Annual														
2023				17,737		(13,947)		(429)	(14,389)	-	-	(24)	(78,937)	**(110,093)**
2024				15,041		-		-	(15,636)	-	-	-	(35,732)	**(49,836)**
2025				4,914		-		-	(14,000)	(9,000)	-	-	(112,699)	**(157,181)**
2026				10,612		-		-	(14,000)	(9,000)	-	-	(80,744)	**(112,614)**
2027				14,987		-		-	(14,000)	(9,000)	-	-	(64,671)	**(90,196)**
2028				18,486		-		-	(14,000)	(9,000)	-	-	(48,032)	**(66,991)**
2029				21,710		-		-	(14,000)	(9,000)	-	-	(49,767)	**(69,409)**

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT 10/31/2023 Exhibit P-9E

Electric Over/(Under) Calculation Schedule SS-TAC-3E

Reflects a tax rate of 28.11%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Monthly Calculations	Over / (Under) Recovery Beginning Balance	Electric Revenues	Revenue Requirement Excluding WACC Cost	Over / (Under) Recovery	Over / (Under) Recovery Ending Balance	Over / (Under) Average Monthly Balance	Interest Rate (Annualized)	Interest On Over / (Under) Average Monthly Balance	Interest Roll-In	Cumulative Interest
Jan-23	(14,935,705)	(9,101,202)	(9,436,537)	335,334	(14,600,371)	(14,768,038)	0.16%	(1,416)	-	(11,231)
Feb-23	(14,600,371)	(8,073,880)	(9,359,172)	1,285,293	(13,315,078)	(13,957,725)	4.64%	(38,799)	-	(50,030)
Mar-23	(13,315,078)	(8,540,596)	(19,619,021)	11,078,425	(2,236,653)	(7,775,866)	4.78%	(22,267)	-	(72,297)
Apr-23	(2,236,653)	(6,993,582)	(5,905,692)	(1,087,890)	(3,324,543)	(2,780,598)	5.32%	(8,862)	-	(81,159)
May-23	(3,324,543)	(7,543,824)	(5,319,679)	(2,224,145)	(5,548,688)	(4,436,616)	5.32%	(14,140)	-	(95,299)
Jun-23	(5,548,688)	(9,671,729)	(9,381,900)	(289,830)	(5,838,518)	(5,693,603)	5.54%	(18,897)	-	(114,196)
Jul-23	(5,838,518)	(14,169,073)	(12,417,153)	(1,751,921)	(7,590,438)	(6,714,478)	5.25%	(21,118)	-	(135,314)
Aug-23	(7,725,752)	(10,458,907)	(10,773,659)	314,752	(7,411,000)	(7,568,376)	5.21%	(23,636)	(135,314)	(23,636)
Sep-23	(7,411,000)	(8,327,826)	(4,893,170)	(3,434,656)	(10,845,656)	(9,128,328)	5.21%	(28,508)	-	(52,144)
Oct-23	(10,845,656)	(6,663,048)	(5,708,894)	(954,154)	(11,799,810)	(11,322,733)	5.49%	(37,206)	-	(89,350)
Nov-23	(11,799,810)	(6,494,340)	(8,298,797)	1,804,457	(9,995,353)	(10,897,582)	5.49%	(35,809)	-	(125,159)
Dec-23	(9,995,353)	(7,973,971)	(8,979,316)	1,005,345	(8,990,009)	(9,492,681)	5.49%	(31,193)	-	(156,352)
Jan-24	(9,146,361)	(2,942,306)	(7,165,805)	4,223,499	(4,922,862)	(7,034,611)	5.49%	(23,116)	(156,352)	(23,116)
Feb-24	(4,922,862)	(2,598,517)	(4,916,039)	2,317,522	(2,605,340)	(3,764,101)	5.49%	(12,369)	-	(35,484)
Mar-24	(2,605,340)	(2,757,529)	(3,936,922)	1,179,393	(1,425,947)	(2,015,643)	5.49%	(6,623)	-	(42,108)
Apr-24	(1,425,947)	(2,369,771)	(1,708,629)	(661,142)	(2,087,089)	(1,756,518)	5.49%	(5,772)	-	(47,879)
May-24	(2,087,089)	(2,568,943)	(1,405,621)	(1,163,322)	(3,250,410)	(2,668,750)	5.49%	(8,769)	-	(56,649)
Jun-24	(3,250,410)	(2,925,404)	(3,555,592)	630,188	(2,620,223)	(2,935,317)	5.49%	(9,645)	-	(66,294)
Jul-24	(2,620,223)	(3,666,482)	(5,163,925)	1,497,444	(1,122,779)	(1,871,501)	5.49%	(6,150)	-	(72,444)
Aug-24	(1,122,779)	(3,534,148)	(4,303,704)	769,555	(353,224)	(738,002)	5.49%	(2,425)	-	(74,869)
Sep-24	(428,093)	(11,571,068)	(2,318,173)	(9,252,895)	(9,680,988)	(5,054,541)	5.49%	(16,609)	(74,869)	(16,609)
Oct-24	(9,680,988)	(11,132,104)	(4,083,260)	(7,048,844)	(16,729,832)	(13,205,410)	5.49%	(43,393)	-	(60,002)
Nov-24	(16,729,832)	(10,378,348)	(5,456,197)	(4,922,151)	(21,651,984)	(19,190,908)	5.49%	(63,061)	-	(123,062)
Dec-24	(21,651,984)	(12,072,828)	(5,821,922)	(6,250,906)	(27,902,890)	(24,777,437)	5.49%	(81,418)	-	(204,480)
Jan-25	(27,902,890)	(12,331,299)	(21,785,568)	9,454,268	(18,448,622)	(23,175,756)	5.49%	(76,155)	-	(280,635)
Feb-25	(18,448,622)	(10,890,470)	(16,555,979)	5,665,509	(12,783,113)	(15,615,867)	5.49%	(51,313)	-	(331,949)
Mar-25	(12,783,113)	(11,556,895)	(14,262,673)	2,705,778	(10,077,335)	(11,430,224)	5.49%	(37,559)	-	(369,508)
Apr-25	(10,077,335)	(9,931,786)	(9,091,899)	(839,887)	(10,917,221)	(10,497,278)	5.49%	(34,494)	-	(404,002)
May-25	(10,917,221)	(10,766,523)	(8,393,353)	(2,373,169)	(13,290,390)	(12,103,806)	5.49%	(39,773)	-	(443,775)
Jun-25	(13,290,390)	(12,260,465)	(13,366,105)	1,105,640	(12,184,750)	(12,737,570)	5.49%	(41,855)	-	(485,630)
Jul-25	(12,184,750)	(15,366,345)	(17,063,358)	1,697,013	(10,487,737)	(11,336,244)	5.49%	(37,251)	-	(522,880)
Aug-25	(10,487,737)	(14,811,731)	(15,037,446)	225,715	(10,262,022)	(10,374,879)	5.49%	(34,092)	-	(556,972)
Sep-25	(10,262,022)	(11,571,068)	(7,852,757)	(3,718,310)	(13,980,332)	(12,121,177)	5.49%	(39,830)	-	(596,802)
Oct-25	(13,980,332)	(11,132,104)	(8,866,197)	(2,265,907)	(16,246,239)	(15,113,286)	5.49%	(49,662)	-	(646,464)
Nov-25	(16,246,239)	(10,378,348)	(12,038,457)	1,660,108	(14,586,131)	(15,416,185)	5.49%	(50,657)	-	(697,121)
Dec-25	(14,586,131)	(12,072,828)	(12,867,548)	794,720	(13,791,411)	(14,188,771)	5.49%	(46,624)	-	(743,745)
	(Prior Col 5) + (Col 9)	Forecasted kWh * Proposed Rate	See Revenue Requirements Schedule for Details	Col 2 - Col 3	Col 1 + Col 4	(Col 1 + Col 5) / 2	Input	(Col 6 * (Col 7) / 12)*net of tax rate		Prior Month + Col 8 - Col 9

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Weighted Average Cost of Capital

Schedule SS-TAC-4

		Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After-Tax Weighted Cost
Long-Term Debt		45.53%	3.96%	1.80%	1.80%	1.30%
Customer Deposits		0.47%	0.87%	0.00%	0.00%	0.00%
Common Equity		54.00%	9.60%	5.18%	7.21%	5.18%
Total		100.00%		6.99%	9.02%	6.48%
Federal Tax Rate	21.00%					0.5402%
State Tax Rate	9.00%					
Fed Benefit of State Tax Deduction	-1.89%					
Effective Tax Rate	28.11%					

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Revenue Factor

Schedule SS-TAC-5

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.2130	0.2130
Rate Counsel Assessment Rate	0.0502	0.0502
Income before State of NJ Bus. Tax	99.7367	99.7367
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7604	90.7604
Federal Income Taxes	19.0597	19.0597
Return	71.7007	71.7007
Revenue Factor	**1.3947**	**1.3947**

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9E

Proposed Electric TAC Calculation

Schedule SS-TAC-6E

($'s Unless Specified)

Current SUT Rate 6.625%

Line		Electric															
		RS	RHS	RLM	WH	WHS	HS	GLP	LPL-S	LPL-P	HTS-S	HTS-HV	BPL	BPL-POF	PSAL	Total	Source/Description
1	2024 Sales (MWh)	13,108,453	81,419	176,712	492	10	9,630	6,816,613	10,257,891	2,792,604	4,404,888	464,483	287,195	14,795	139,211	38,554,397	Input
2	Rate Class Allocation[1]	71.15%	0.63%	0.90%	0.00%	0.00%	0.03%	12.26%	10.44%	1.82%	2.64%	0.11%	0.00%	0.02%	0.00%	100.00%	CreditCalc-E TAC 2023
3	Revenue Requirements	(24,289,116)	(213,548)	(307,373)	0	0	(11,887)	(4,186,254)	(3,563,230)	(620,689)	(900,890)	(37,360)	0	(6,793)	0	(34,137,139)	CreditCalc-E TAC 2023
4	Proposed Rate w/o SUT ($/kWh)	(0.001853)	(0.002623)	(0.001739)	0.000000	0.000000	(0.001234)	(0.000614)	(0.000347)	(0.000222)	(0.000205)	(0.000080)	0.000000	(0.000459)	0.000000		CreditCalc-E TAC 2023
5	Public Notice Rate w/o SUT ($/kWh)																CreditCalc-E TAC 2023
6	Proposed Rate w/ SUT ($/kWh)	(0.001976)	(0.002797)	(0.001854)	0.000000	0.000000	(0.001316)	(0.000655)	(0.000370)	(0.000237)	(0.000219)	(0.000085)	0.000000	(0.000489)	0.000000		CreditCalc-E TAC 2023
7	Sep-24 to Dec-25 Sales (MWh)	17,097,213	107,726	231,068	696	10	13,320	9,448,710	13,621,964	3,987,859	6,099,158	581,140	389,656	19,549	186,559	51,784,628	
8	Rate Class Allocation	71.19%	0.63%	0.90%				12.27%	10.44%	1.82%	2.64%	0.11%				100.00%	Line 2 / Sum Line 2
9	Revenue Requirements	(133,997,836)	(1,178,096)	(1,695,709)	0	0	0	(23,094,662)	(19,657,573)	(3,424,207)	(4,970,019)	(206,108)	0	0	0	(188,224,210)	(SS-TAC-1, ln 4 [Electric]) * Line 8 * 1000
10	Proposed Rate w/o SUT ($/kWh)	(0.007837)	(0.010936)	(0.007339)	0.000000	0.000000	0.000000	(0.002444)	(0.001443)	(0.000859)	(0.000815)	(0.000355)	0.000000	0.000000	0.000000		(Line 7 / (Line 9 * 1,000)) [Rnd 6]
11	Public Notice Rate w/o SUT ($/kWh)																
12	Proposed Rate w/ SUT ($/kWh)	(0.008356)	(0.011661)	(0.007825)	0.000000	0.000000	0.000000	(0.002606)	(0.001539)	(0.000916)	(0.000869)	(0.000379)	0.000000	0.000000	0.000000		(Line 10 * (1 + SUT Rate)) [Rnd 6]
13	Jun-23 to May 24 Sales (MWh)	13,044,353	83,042	176,965	523	8	10,350	7,084,026	10,200,967	2,944,785	4,541,551	435,991	285,913	14,294	137,182	38,959,950	Input
14	Annulization Factor	76.30%	77.09%	76.59%				74.97%	74.89%	73.84%	74.46%	75.02%					(Line 7) / (Line 13)
15	Annualized Revenue Requirements	(102,233,919)	(908,148)	(1,298,668)	0	0	0	(17,314,870)	(14,720,804)	(2,528,564)	(3,700,772)	(154,629)	0	0	0	(142,860,375)	(Line 9) * (Line 14)
16	Filed Rates 2024	(0.001853)	(0.002623)	(0.001739)	0.000000	0.000000	(0.001234)	(0.000614)	(0.000347)	(0.000222)	(0.000205)	(0.000080)	0.000000	(0.000459)	0.000000		Line 4
17	Test Year Revenue Requirements at Filed Rates 2024	(24,171,186)	(217,819)	(307,741)	0	0	(12,772)	(4,349,592)	(3,539,736)	(653,742)	(931,018)	(34,879)	0	(6,561)	0	(34,225,047)	(Line 13 * Line 16)*1000
18	Annualized Change	(78,062,733)	(690,329)	(990,927)	0	0	12,772	(12,965,278)	(11,181,068)	(1,874,821)	(2,769,754)	(119,750)	0	6,561	0	(108,635,328)	Line 15 - Line 17
19	16 Month Revenue Requiremnets at Filed 2024 Rates	(31,681,136)	(282,566)	(401,827)	0	0	(16,437)	(5,801,508)	(4,726,822)	(885,305)	(1,250,327)	(46,491)	0	(8,973)	0	(45,101,391)	(Line 7 * Line 16)*1000

[1]Rate Class Allocation remains the same and stays in effect until the conclusion of the Company's next Base Rate Case

PSE&G Electric - Storm Recovery Charge

Schedule SS-SRC-1E

SRC Electric Rate Calculation

($'s - Unless noted)

Line No.	Calculation	Description	
1		Deferred Storm Cost Balance as of 9/1/24	105,073,253
2		Estimated Interest Expenses	8,880,588
3	=(1+2)/3 Years	Estimated Annual Revenue Requirement	37,984,614
4		Forecasted Annual kWh	39,579,987,063
5	=3/4	Proposed SRC ($/kWh excluding Sales & Use Tax)	0.000959
6	=5*(1+SUT%)	Proposed SRC ($/kWh Including Sales and Use Tax)	0.001023
7		Existing SRC ($/kWh Including Sales & Use Tax)	0.000000
8	=(5-7)*4	Storm Recovery Charge Increase / (Decrease)	37,957,208

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation

Schedule SS-SRC-2E

($'s - Unless noted)

Month	(1) Input SRC Revenue	(2) Input Incremental Deferred Major Storm Expenses	(3) Prior Col 6 - Col 1 + Col 2 Prior Month (Over)/Under Balance + Monthly Activity)	(4) Input Annual Interest Rate	(5) (Prior Col 6 + Col 3) / 2 * (Col 4 / 12) Interest Expense	(6) Col 3 + Col 5 SRC Balance - (Over)/Under
Aug-24						105,073,253
Sep-24	3,258,053	-	101,815,200	5.43%	467,740	102,282,941
Oct-24	2,858,444	-	99,424,497	5.43%	456,027	99,880,523
Nov-24	2,897,302	-	96,983,222	5.43%	445,076	97,428,298
Dec-24	3,163,531	-	94,264,767	5.43%	433,386	94,698,153
Jan-25	3,243,290	-	91,454,863	5.43%	420,861	91,875,724
Feb-25	2,846,849	-	89,028,875	5.43%	408,995	89,437,870
Mar-25	3,050,903	-	86,386,967	5.43%	397,511	86,784,478
Apr-25	2,607,703	-	84,176,774	5.43%	386,515	84,563,289
May-25	2,826,288	-	81,737,001	5.43%	375,977	82,112,978
Jun-25	3,318,797	-	78,794,181	5.43%	363,784	79,157,965
Jul-25	4,028,686	-	75,129,279	5.43%	348,818	75,478,096
Aug-25	3,976,100	-	71,501,996	5.43%	332,297	71,834,294
Sep-25	3,256,799	-	68,577,495	5.43%	317,448	68,894,942
Oct-25	2,849,948	-	66,044,994	5.43%	305,077	66,350,071
Nov-25	2,873,892	-	63,476,179	5.43%	293,516	63,769,694
Dec-25	3,182,661	-	60,587,033	5.43%	281,150	60,868,183
Jan-26	3,238,321	-	57,629,862	5.43%	267,904	57,897,767
Feb-26	2,823,434	-	55,074,333	5.43%	255,411	55,329,744
Mar-26	3,021,906	-	52,307,838	5.43%	243,351	52,551,189
Apr-26	2,531,868	-	50,019,320	5.43%	231,895	50,251,215
May-26	2,864,980	-	47,386,236	5.43%	220,742	47,606,978
Jun-26	3,256,489	-	44,350,488	5.43%	207,901	44,558,389
Jul-26	4,016,272	-	40,542,117	5.43%	192,398	40,734,515
Aug-26	3,958,044	-	36,776,470	5.43%	175,239	36,951,710
Sep-26	3,237,273	-	33,714,437	5.43%	159,764	33,874,202
Oct-26	2,784,985	-	31,089,217	5.43%	146,871	31,236,088
Nov-26	2,866,377	-	28,369,711	5.43%	134,759	28,504,470
Dec-26	3,169,822	-	25,334,649	5.43%	121,721	25,456,370
Jan-27	3,312,567	-	22,143,803	5.43%	107,616	22,251,419
Feb-27	2,847,490	-	19,403,929	5.43%	94,176	19,498,104
Mar-27	3,011,391	-	16,486,713	5.43%	81,356	16,568,069
Apr-27	2,609,086	-	13,958,983	5.43%	69,017	14,028,000
May-27	2,894,918	-	11,133,081	5.43%	56,885	11,189,966
Jun-27	3,228,713	-	7,961,253	5.43%	43,298	8,004,551
Jul-27	4,039,724	-	3,964,827	5.43%	27,061	3,991,888
Aug-27	3,982,449	-	9,439	5.43%	9,046	18,485

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation

Schedule SS-SRC-3E

($'s - Unless noted)

(1)	(2)	(3)
Input	Input	[Schedule SS-SRC-1E] Line 5 x Col 2
Rate Class	**Annual kWh**	**Annual Revenue**
RS	13,390,516,645	12,841,505
RHS	74,071,772	71,035
RLM	174,889,380	167,719
WH	554,008	531
WHS	7,013	7
HS	9,842,905	9,439
BPL	249,631,666	239,397
BPL-POF	13,978,769	13,406
PSAL	108,941,398	104,475
GLP	6,916,145,205	6,632,583
LPL-S	10,020,481,341	9,609,642
LPL-P	2,882,687,883	2,764,498
HTS-S	5,068,122,778	4,860,330
HTS-HV	670,116,301	642,642
Total	39,579,987,063	37,957,208

PSE&G Residential Electric Vehicle Cost of Service Study

Exhibit P-9
Schedule SS-EV-1

System Peak	10,147,020	kW
Peak Date	8/9/2022 Tuesday	
Peak Hour Ending	17	i.e. 4-5pm

Customers	826			
Sum of Peaks	16,651	kW		
CP	34	kW		
Total Usage	2,921,627	kWh		
			5n7	
Local Delivery	$ 470,258,234	Sum of Peaks	from 5n7 Cost of Service output	
System Delivery	$ 300,953,037	Coincident Peaks	from 5n7 Cost of Service output	
			Scaled	
RS Customers	2,000,647		0.04%	
RS WN Sum of Peaks	11,830,661	kW	4,884	kW
RS WN Coincident Peak	4,362,852	kW	1,801	kW
RS Usage	13,046,972,126	kWh	5,386,657	kWh

	RS Cost Rate	
RS Local Delivery Rate	0.036043	
RS System Delivery Rate	0.023067	
Total	0.05911	$/kWh

RS EV Sum of Peak Ratio	0.1407%	
RS EV Coincident Peak Ratio	0.0008%	

RS EV Sum of Peaks $	$ 661,857	$ 194,154
RS EV Coincident Peak $	$ 2,348	$ 124,253
Total $	$ 664,204	$ 318,407

	EV Cost Rate	
RS EV Sum of Peaks Rate	$ 0.226537	
RS EV Coincident Peak Rate	$ 0.000804	
Total Rate	$ 0.227341	$/kWh

	Proposed Avg RS Rate	
proposed RS Dist kWh rev	763,438,000	
RS WN annual kWh	13,044,353	MWh
RS Proposed avg kWh rate	0.058526	$/kWh

PSE&G Non-Residential Electric Vehicle Cost of Service Study

Exhibit P-9
Schedule SS-EV-2

Customers	34			
Sum of Peaks	17,678	kW		
Coincident Peak	6,187	kW		
Total Usage	30,361,295	kWh		
			5n7	
Local Delivery	$ 102,876,070	Sum of Peaks	from 5n7 Cost of Service output	
System Delivery	$ 126,845,827	Coincident Peaks	from 5n7 Cost of Service output	
			Scaled	(for reference)
LPL-S Customers	9,532		0.36%	
LPL-S WN Sum of Peaks	2,893,512	kW	10,321	kW
LPL-S WN Coincident Peak	1,946,767	kW	6,944	kW
LPL-S Usage	10,497,945,935	kWh	37,443,827	kWh

System Peak	10,147,020 kW
Peak Date	8/9/2022 Tuesday
Peak Hour Ending	17 i.e. 4-5pm

LPL-S Local Delivery Rate	0.0098
LPL-S System Delivery Rate	0.012083
Total	0.021883
LPL-S EV Sum of Peaks Ratio	0.6110%
LPL-S EV Coincident Peak Ratio	0.3178%

LPL-S EV Sum of Peaks $	$ 628,538	$ 366,936
LPL-S EV Coincident Peak $	$ 403,125	$ 452,431
Total $	$ 1,031,663	$ 819,367

	EV Cost Rate
LPL-S EV Coincident Peak Rate	$ 0.020702
LPL-S EV Sum of Peaks Rate	$ 0.013278
Total	$ 0.033980

Rate Revenue	$ 215,064,000
COS Rev	$ 229,721,897
Ratio of Rate Revenue to COS	0.93619

	Proposed EV Rate - $/kWh		
DCFC Distribution kWh	0.031812	w/o SUT	Sales Tax Factor
DCFC Distribution kWh	0.033920	w/SUT	1.06625

PSE&G CEF Electric Vehicle Program **Exhibit P-9E**
Rate Adjustment Calculation CEF-EV-1
Sample Calculation
in ($000)

Rate Effective Date	**4/1/2025**	
Plant In Service as of Date	12/31/2025	
Rate Base Balance as of Date	3/31/2025	

RATE BASE CALCULATION

		Total	Notes
1	Gross Plant	$3,900	= ln 17
2	Regulatory Asset	$4,714	= ln 22 + ln 28 + ln 56
3	Accumulated Depreciation	($42)	= ln 28
4	Net Plant	$8,572	= ln 1 + ln 2 + ln 3
5	Accumulated Deferred Taxes	($1,177)	= ln 45
6	Rate Base	$7,395	= ln 4 + ln 5
7	Rate of Return - After Tax	7.55%	See Rate Case Schedule MPM-04 (WACC)
8	Return Requirement (After Tax)	$558	= ln 6 * ln 7
9	Depreciation Exp, net	$205	= ln 66
10	O&M Expense Regualtory Asset Amortization - After Tax	$563	= ln 70
11	Revenue Factor	1.3947	See Rate Case Schedule MPM-06 (Revenue Factor)
12	**Total Revenue Requirement**	**$1,850**	= (ln 8 + ln 9 + ln 10) * ln 11

SUPPORT

Investment

Real Assets (Pole to Meter)

13	Residential Smart Charging	$1,300	See "RevReq Detial Wkps
14	Mixed Use	$1,300	See "RevReq Detial Wkps
15	DCFC	$1,300	See "RevReq Detial Wkps
16	IT System Enhancements	$0	See "RevReq Detial Wkps
17	Total Real Assets	$3,900	= ln 13 + ln 14 + ln 15 + ln 16

Regulatory Assets (Meter to Stub / Rebates)

18	Residential Smart Charging	$1,300	See "RevReq Detial Wkps
19	Mixed Use	$1,300	See "RevReq Detial Wkps
20	DCFC	$1,560	See "RevReq Detial Wkps
21	IT System Enhancements	$0	See "RevReq Detial Wkps
22	Total Regulatory Assets	$4,160	= ln 18 + ln 19 + ln 20 + ln 21
23	**Total Investment**	**$8,060**	= ln 17 + ln 22

Depreciation & Amortization

Real Assets (Pole to Meter)

24	Residential Smart Charging	$14	See "RevReq Detial Wkps
25	Mixed Use	$14	See "RevReq Detial Wkps
26	DCFC	$14	See "RevReq Detial Wkps
27	IT System Enhancements	$0	See "RevReq Detial Wkps
28	Total Real Assets	$42	= ln 24 + ln 25 + ln 26 + ln 27

Regulatory Assets (Meter to Stub / Rebates)

29	Residential Smart Charging	$23	See "RevReq Detial Wkps
30	Mixed Use	$23	See "RevReq Detial Wkps
31	DCFC	$52	See "RevReq Detial Wkps
32	IT System Enhancements	$0	See "RevReq Detial Wkps
33	Total Regulatory Assets	$99	= ln 29 + ln 30 + ln 31 + ln 32
34	**Total Depreciation & Amortization**	**$141**	= ln 28 + ln 33

PSE&G CEF Electric Vehicle Program **Exhibit P-9E**
Rate Adjustment Calculation CEF-EV-1
Sample Calculation
in ($000)

	ADIT		
	Real Assets (Pole to Meter)		
35	Residential Smart Charging	$12	See "RevReq Detial Wkps
36	Mixed Use	$12	See "RevReq Detial Wkps
37	DCFC	$12	See "RevReq Detial Wkps
38	IT System Enhancements	$0	See "RevReq Detial Wkps
39	Total Real Assets	$35	= ln 35 + ln 36 + ln 37 + ln 38
	Regulatory Assets (Meter to Stub / Rebates)		
40	Residential Smart Charging	$359	See "RevReq Detial Wkps
41	Mixed Use	$359	See "RevReq Detial Wkps
42	DCFC	$424	See "RevReq Detial Wkps
43	IT System Enhancements	$0	See "RevReq Detial Wkps
44	Total Regulatory Assets	$1,142	= ln 40 + ln 41 + ln 42 + ln 43
45	**Total ADIT**	**$1,177**	= ln 39 + ln 44
	Deferred Return / Carrying Charges		
	Real Assets (Pole to Meter)		
46	Residential Smart Charging	$83	See "RevReq Detial Wkps
47	Mixed Use	$83	See "RevReq Detial Wkps
48	DCFC	$82	See "RevReq Detial Wkps
49	IT System Enhancements	$0	See "RevReq Detial Wkps
50	Total Real Assets	$248	= ln 46 + ln 47 + ln 48 + ln 49
	Regulatory Assets (Meter to Stub / Rebates)		
51	Residential Smart Charging	$83	See "RevReq Detial Wkps
52	Mixed Use	$83	See "RevReq Detial Wkps
53	DCFC	$98	See "RevReq Detial Wkps
54	IT System Enhancements	$0	See "RevReq Detial Wkps
55	Total Regulatory Assets	$264	= ln 51 + ln 52 + ln 53 + ln 54
56	**Total Deferred Return / Carrying Charges**	**$512**	= ln 50 + ln 55
	Amortization Period		
57	Residential Smart Charging	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
58	Mixed Use	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
59	DCFC	30	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
60	IT System Enhancements	5	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
	Amortization Recovery		
61	Residential Smart Charging	$92	= (ln 13 + ln 18 + ln 46 + ln 51) / ln 57
62	Mixed Use	$92	= (ln 14 + ln 19 + ln 47 + ln 52) / ln 58
63	DCFC	$101	= (ln 15 + ln 20 + ln 48 + ln 53) / ln 59
64	IT System Enhancements	$0	= (ln 16 + ln 21 + ln 49 + ln 54) / ln 60
65	Total D&A Recovery	$286	= ln 61 + ln 62 + ln 63 + ln 64
66	Total D&A (Net of Tax)	$205	= ln 65 * 1 - Tax Rate
	O&M Expense Regualatory Asset Amortization		
67	CEF-EV O&M Expenses	$3,913	See "RevReq Detial Wkps
68	Amortization Period (Years)	5	See Rate Case Schedule MPM-49 (Amort of CEF-EV Program)
69	Annaul CEF-EV O&M Expenses Amortization	$783	= ln 67 / ln 68
70	Total O&M Expense (Net of Tax)	$563	= ln 69 * 1 - Tax Rate

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY OF

STEPHEN SWETZ

SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

ON GAS COST OF SERVICE AND RATE DESIGN

December 29, 2023
P-9G

TABLE OF CONTENTS

SCOPE OF TESTIMONY ..... - 1 -

OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSIS ..... - 4 -
Overview ..... - 4 -
Weather Normalization of Billing Determinants ..... - 13 -
Scope of the COSS ..... - 13 -
Adjustments to Accounting Data ..... - 14 -

COSS OVERVIEW ..... - 14 -
Introduction ..... - 14 -
Cost Allocation Concepts ..... - 15 -
General Cost Allocation and Functionalization Methodology ..... - 15 -
Functionalization into Five Segments ..... - 16 -
Access Segment ..... - 18 -
Delivery Segment ..... - 18 -
Street Lighting Fixtures Segment ..... - 18 -
Customer Service Segment ..... - 19 -
Measurement Segment ..... - 19 -
Modeling Procedure ..... - 19 -
Synchronizing the COSS to the Rate Design ..... - 22 -

RATE DESIGN ..... - 23 -
Introduction ..... - 23 -
Limitations on Rate Changes ..... - 24 -
Inter Class Revenue Increase Allocations ..... - 25 -
General Rate Design Principles and Methodology ..... - 28 -

RATE SCHEDULE SPECIFIC CHANGES ..... - 29 -
Rate Schedule Residential Service Gas ("RSG") ..... - 29 -
Rate Schedule General Service Gas ("GSG") ..... - 30 -
Rate Schedule Large Volume Gas ("LVG") ..... - 31 -
Rate Schedule Street Lighting Gas ("SLG") ..... - 32 -
Rate Schedule Transportation Service Gas – Firm ("TSG-F") ..... - 32 -
Rate Schedule Transportation Service Gas – Non Firm ("TSG-NF") ..... - 33 -
Rate Schedule Co-Generation Industrial Gas ("CIG") ..... - 33 -
Rate Schedule Contract Service Gas ("CSG") ..... - 34 -

TARIFF CHANGES ..... **- 34 -**

TAX ADJUSTMENT CREDIT ("TAC") ..... **- 34 -**

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC") ..... **- 36 -**
SRC Mechanism ..... - 36 -
SRC Components ..... - 37 -

GAS BAD DEBT RECOVERED VIA THE SBC ..... **- 38 -**

STAFF COSS METHODOLOGY ..... **- 39 -**
Subsequent Base Case Requirements ..... - 41 -

APPENDIX G-1 - DETAILED REVIEW OF COST OF SERVICE STUDY - 42 -

ALLOCATOR NAMING CONVENTION ..... **- 42 -**
Direct Allocators ..... - 42 -
Indirect Allocators ..... - 43 -

ALLOCATION DETAILS ..... **- 43 -**
Intangible Plant ..... - 43 -
Production Plant ..... - 43 -
Storage Plant ..... - 44 -
Transmission Plant ..... - 44 -
Distribution Plant ..... - 44 -
Other Distribution Plant ..... - 45 -
General, Common and Other Plant ..... - 46 -
Depreciation Reserve ..... - 46 -
Adjustments to Develop Rate Base ..... - 47 -
Operating Revenues ..... - 47 -
Production Expenses ..... - 48 -
Gas Supply Expenses ..... - 48 -
Other Storage Expenses ..... - 48 -
Transmission and Distribution O&M Expenses ..... - 48 -
Customer Accounts, Service and Sales Expense ..... - 49 -
Administrative and General (A&G) Expenses ..... - 50 -
Depreciation and Amortization Expenses ..... - 50 -
Taxes Other Than Income Taxes ..... - 50 -
Pro Forma Expense Adjustments ..... - 50 -
Taxes ..... - 52 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS
ON
GAS COST OF SERVICE AND RATE DESIGN

Q. Please state your name, affiliation and business address.

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My credentials are set forth in the attached Schedule SS-G1.

Q. Please describe your responsibilities as Senior Director - Corporate Rates and Revenue Requirements.

A. In this position I have, among other things, responsibility for the development of rates and tariffs for Public Service Electric and Gas Company ("PSE&G" or "Company").

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. I have both submitted written testimony and testified live before the BPU in a number of proceedings that are identified in Schedule SS-G1.

SCOPE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the Company's proposed changes to its rates for Gas Service, which are designed to recover the revenue requirements for the gas distribution business as presented in this filing. My testimony provides the Company's embedded cost of service study ("Company COSS") used as the basis for development of the new gas rates and the proposed rate design for each rate schedule in PSE&G's Gas Tariff. I also present an

alternative embedded cost of service study ("the Staff COSS") as required under the 2018 Rate Case Order and explain why that COSS should not be used to set rates in this case.[1]

Additionally, I sponsor other studies and modifications to the Company's Tariff for Gas Service ("Tariff") including the following:

- Recovering Gas Bad Debt Costs consistent with method used in electric business; and
- The establishment of a Storm Recovery Charge ("SRC") to recover major storm costs as a component of a proposed Distribution Adjustment Charge ("DAC") that was previously proposed as part of the COVID-19 cost recovery proceeding;[2]
- Tax Adjustment Credit ("TAC") modifications.

I also sponsor the Company's proposed Tariff, which is attached to the Company's Petition in Exhibit P-1 as Schedule 3.

[1] *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 & GR18010030; *I/M/O the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*; BPU Docket No. AX18010001; *I/M/O Public Service Electric and Gas Company for Approval of Revised Rates (Effective on an Interim Basis April 1, 2018) to Reflect the Reduction Under the Tax Cuts and Jobs Act of 2017*, BPU Docket No. ER18030231, Decision and Order Adopting Initial Decision and Stipulation (October 29, 2018) (the "2018 Rate Case Order"), paragraph 25.

[2] *I/M/O the New Jersey Board of Public Utilities Response to the COVID-19 Pandemic*, BPU Docket No. AO20060471, PSE&G filing titled *I/M/O the Petition of Public Service Electric and Gas Company for Approval of Incremental COVID-19 Costs for Recovery Through a New Special-Purpose Clause, and for Authorization to Recover Uncollectible Costs for Gas Through the Societal Benefits Charge* (July 17, 2023).

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared and/or compiled by me or under my direction and supervision:

SCHEDULE DESCRIPTION	NUMBER
Qualifications of Stephen Swetz	SS-G1
Basis of Calculations Schedules	
Actual and Weather Normalized Billing Determinants	SS-G2
COSS Adjustments	SS-G3
Cost of Service Schedules	
Details of Complete COSS	SS-G4
COSS Summary Report by Functional Segment	SS-G5
COSS Revenue Requirements by Rate and Function	SS-G6
Sync with Rate Design	SS-G7
Rate and Rate Design Schedules	
Inter Class Revenue Increase Allocations	SS-G8
Service Charge Calculations	SS-G9
BGSS Calculations	SS-G10
Proof of Revenue by Rate Schedule	SS-G11
Typical Customer Bill Impacts by Rate Schedule	SS-G12
Staff's Cost Allocation Methodology Related Schedules	
Details of Complete COSS – Staff's Method	SS-G13
Summary Report – by Functional Segment – Staff's Method	SS-G14
Functional Cost Summary – Staff's Method	SS-G15

Service Charge Calculations – Staff's Method.....SS-G16

Tax Adjustment Credit ("TAC") Schedules

TAC Revenue Requirement and Rate Calculations.....SS-TAC-1-6G

SRC Schedules

SRC Balance and Rate Calculations.....SS-SRC 1-3G

Societal Benefits Charge ("SBC") Schedules

SBC Social Programs Rate Balance and Calculations.....SS-SBC-1-2

OVERVIEW OF THE COMPANY'S RATE FILING AND BASIS OF CALCULATIONS AND ANALYSIS

Overview

Q. What terminology does your direct testimony use regarding revenue and rates?

A. Throughout this testimony, the revenue or percentage increase for "Distribution" is based only on revenue from the Service Charge and Distribution Charge(s) for the particular rate schedule. The term "Delivery" refers to revenue from the Service Charge and Distribution Charges as indicated on the particular rate schedule, plus the revenue from the Balancing Charge and all of the applicable adjustment clauses. The "Total Bill" equals the Delivery Charges plus gas supply, and is calculated as if all customers were supplied on Basic Gas Supply Service ("BGSS").

Q. Please describe the gas distribution services provided by the Company.

A. The Company provides gas distribution services under the following Rate Schedules:

(i) Rate Schedule RSG sets forth the terms at which the Company provides firm delivery service for residential purposes;

(ii) Rate Schedule GSG sets forth the terms at which the Company provides firm delivery service to customers that do not qualify for Rate Schedule RSG and whose usage does not exceed 3,000 therms in any month;

(iii) Rate Schedule LVG sets forth the terms at which the Company provides firm delivery service for general purposes;

(iv) Rate Schedule SLG sets forth the terms at which the Company provides firm delivery service for gas street lighting purposes as well as lamp posts and maintenance;

(v) Rate Schedule TSG-F is a closed service that was available to customers who purchased or committed to purchase service prior to December 1, 1994 and whose maximum request for firm gas is not less than 150 therms per hour;

(vi) Rate Schedule TSG-NF sets forth the terms at which the Company provides interruptible delivery service to customers whose maximum request for gas is not less than a 150 therms per hour; and

(vii) Rate Schedule CIG is a closed interruptible service that was available to cogeneration customers who purchased or committed to purchase service prior to January 9, 2002.

(viii) Rate Schedule CSG is a firm or interruptible delivery service for general purposes where the customer is requesting a discount rate from a Public Service Rate Schedule for delivery service based on an (a) Economically Viable Bypass alternative or (b) Other Considerations.

Q. Please provide an overview of the Company's filing in this proceeding.

A. As described more fully by Company witness Mr. Michael McFadden's, PSE&G is seeking to increase its base delivery rates effective September 1, 2024 by approximately $422.8 million annually for its gas distribution business. As discussed further by Mr. McFadden and Company witness Mr. Cliff Pardo, the Company further proposes to make certain modifications to the Company's TAC, including flowing back Mixed Service deductions to customers. This change will reduce gas rates by approximately $102.0 million annually. In addition, the Company is

proposing the SRC to recover major storm costs, increasing gas rates by approximately $1.3 million annually. Finally, the Company is proposing to recover it gas bad debt costs through a new Social Programs component of the SBC for approximately $42.0 million. My testimony provides support on how these changes will impact rates.

Q. **How have Gas distribution charges changed since the 2018 base rate case?**

A. Gas distribution charges have increased at a compound annual growth rate ("CAGR") of 4.3% as shown in Figure 1. This increase is primarily driven by work to modernize the Gas system and replace cast iron and unprotected steel mains, which provide both a reliability and carbon emissions benefit to customers. Despite the considerable investment to modernize the gas system, the distribution charge CAGR for a residential customer using 1,000 therms per year is less than half of the statewide average of 10.6%. PSE&G's charges have increased considerably less than the New Jersey average because PSE&G has been able to control costs and maximize the value of its prior investments.

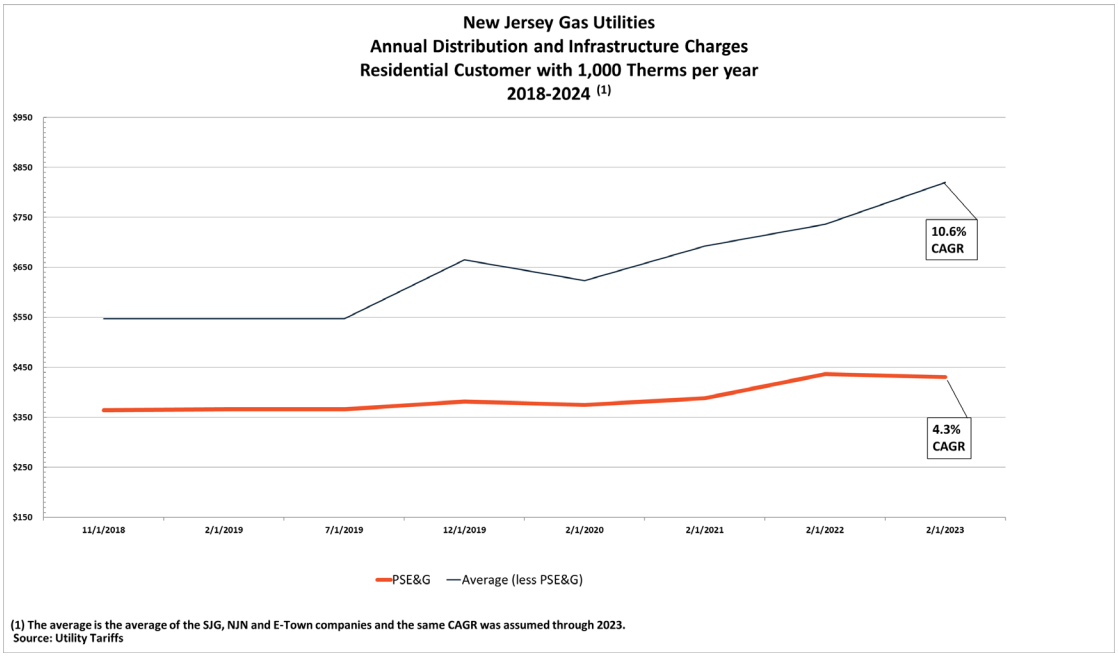


Figure 1

Q. **That shows that PSE&G's Distribution charges are lower than average, but how does PSE&G compare on a total bill basis?**

A. PSE&G continues to be lower than the average compared to its peers. In New Jersey, PSE&G remains on the lower cost side compared to of all of its peers in terms of the total gas and electric bill. Further, as shown in Figure 2 below, the Company has the lowest monthly gas bill amongst all of its peers – almost 27% lower than the average, as set forth in Figure 2 below.

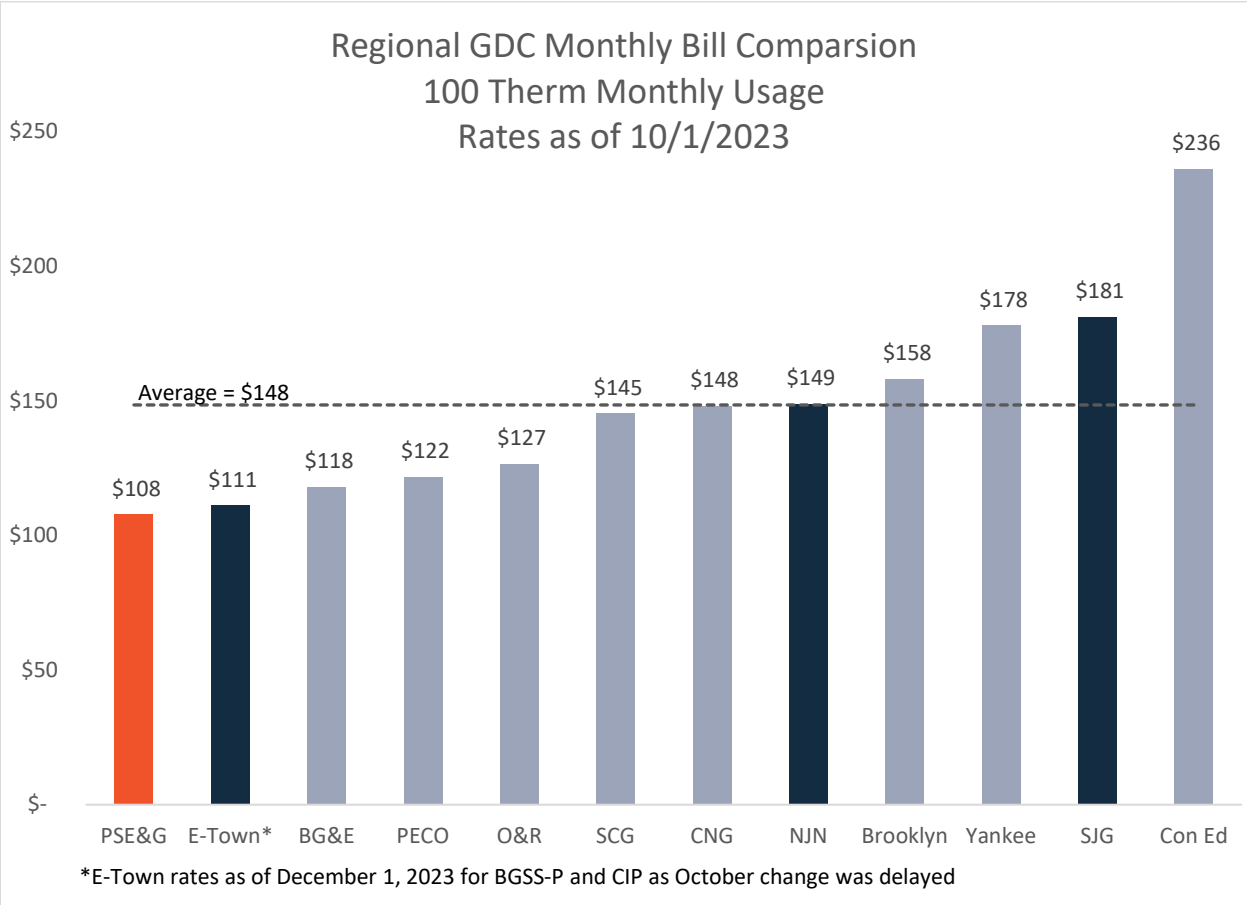


Figure 2

Q. How long has it been since PSE&G's last base rate case?

A. PSE&G filed its last base rate case on January 12, 2018, with new rates effective November 1, 2018. Since that time, every other NJ gas utility has filed at least two base rate cases.

Q. Why has PSE&G not filed a rate case until now?

A. As discussed in more detail below, this is primarily due to the Company's efforts to control costs. PSE&G takes very seriously its responsibility to customers to manage costs prudently and be good stewards of the gas distribution system and the customer funds needed to operate and maintain it effectively. This is achieved by regularly benchmarking Company costs and employee performance and creating appropriate employee incentives to continue to improve upon historic success.

Q. Please describe the efforts the Company has undertaken to protect lower-income customers from the impact of rate increases.

A. The Company is very focused on this vulnerable segment of our customer base. PSE&G's Energy Efficiency programs include incentives targeted to its lower income customers, with specific opportunities for both low and moderate income customers, who often face the highest energy burdens. The Company specifically seeks to provide energy savings opportunities to these customers in order to lower their energy burdens, as participants in the EE programs are expected to benefit from long term energy and bill savings, as well as health and safety improvements. The Company implements the State's Comfort Partners program to customers with incomes up to 250% of the Federal Poverty Level; that program provides free comprehensive energy savings solutions as well as upgrades to address health and safety problems in the home. PSE&G also recently filed its updated Clean Energy Future – Energy Efficiency II Program, which proposes to transfer administration of the Comfort Partners program to the Company in order further reduce market confusion and streamline the process for lower-income customers to take advantage of energy efficiency programs;[3] PSE&G believes this change in administration of the Comfort

[3] *I/M/O The Petition of Public Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency II (CEF-EE I) Program on A Regulated Basis*, BPU Docket No. QO23120874 (filed December 1, 2023).

Partners program will significantly improve customer access to energy efficiency and allow the Company more flexibility in serving the needs of lower-income customers. Also as part of the Clean Energy Future – Energy Efficiency II Program, PSE&G proposed to continue to target low and moderate income customers by providing comprehensive energy assessments and free direct install of energy efficient measures and services to income qualified households with higher incentives and opportunities for no-interest financing for health and safety improvements to these customers (the Comfort Partners program does not include financing, as all measures are paid for by the program and free to eligible customers), and to continue to provide enhanced opportunities for customers in overburdened communities. PSE&G also offers higher incentives for high efficiency heating and cooling systems and continues to provide financial incentives to both property owners and tenants to install high efficiency equipment in apartments and other multifamily properties. The Company promotes the use of these programs to our customers through bill inserts and community outreach, conducting this communication in multiple languages where possible and appropriate.

Q. Are there other assistance programs for lower-income customers outside of PSE&G's energy efficiency programs, and if so, please describe those programs and who is eligible.

A. The Company also advocates at the State and Federal level for various grants provided to lower-income customers, including the Low-Income Home Energy Assistance Program ("LIHEAP"), Lifeline and Tenants Lifeline Program ("Lifeline"), and the Universal Service Fund ("USF"). LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for their winter heating bills, medically necessary cooling benefits, and weatherization. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at least age 65, or at least age 18 and collecting

Social Security Disability. In addition, a single person must make less than $42,000, or a couple less than $49,000 annually. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric, including electric heating for customers at or below 60% of the State median income. PAGE is a program for customers earning up to 500% of the Federal Poverty Limits and offers a grant of up to $700 per utility service. NJ SHARES is for customers earning up to 400% of the Federal Poverty Limit and is funded by customer donations which are matched by PSE&G.

PSE&G has more customers eligible for these low-income programs on a proportionate basis compared with other New Jersey utilities. This customer segment receives special focus.

Q. Are there steps PSE&G has taken during the COVID-19 pandemic to help these customers?

A. Yes. PSE&G, its customers, and New Jersey have faced unprecedented challenges as a result of the COVID-19 global pandemic that created difficult economic circumstances. In response to these challenges, PSE&G developed a comprehensive payment assistance outreach plan utilizing employees and contractors and conducted an external media campaign designed to provide customers opportunities to garner financial assistance and enter into deferred payment arrangements to avoid shut off.

Q. Has the Company considered the impact of gas rates on these customers?

A. Yes. As illustrated in the figure below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer has dropped significantly since 2009 and is essentially flat as compared with rates following the conclusion of the Company's 2018 base rate case.

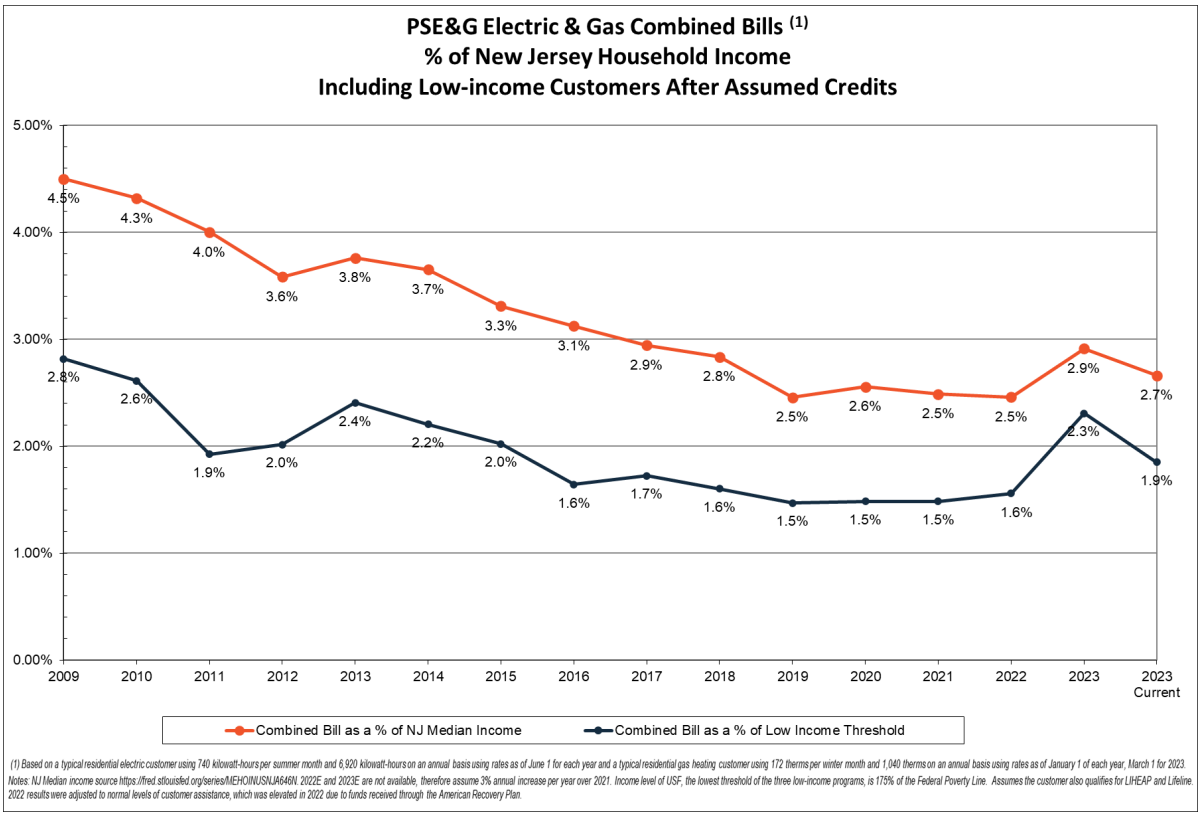


Figure 3

This chart compares the bill as a percentage of income for a typical combined electric and gas residential customer relative to New Jersey's median income and relative to the income threshold below which customers are considered low-income. As can be seen, for the average residential customer, the cost of service is less than 3% of median income. For lower-income customers, the cost of the bill after LIHEAP, USF, and Lifeline grants relative to an income level of 60% of State median income (the level at which a customer is eligible for these grants), is around 2% today. So, even with this proposed rate increase, the cost of electricity and gas for all of the Company's customers, including low-income customers, remains a very small portion of overall income for those able to take advantage of these programs.

Q. How does the current RSG Service Charge compare to other utilities?

A. As shown in the figure below, PSE&G's monthly RSG gas service charge is the lowest compared to similar gas utilities in the region.

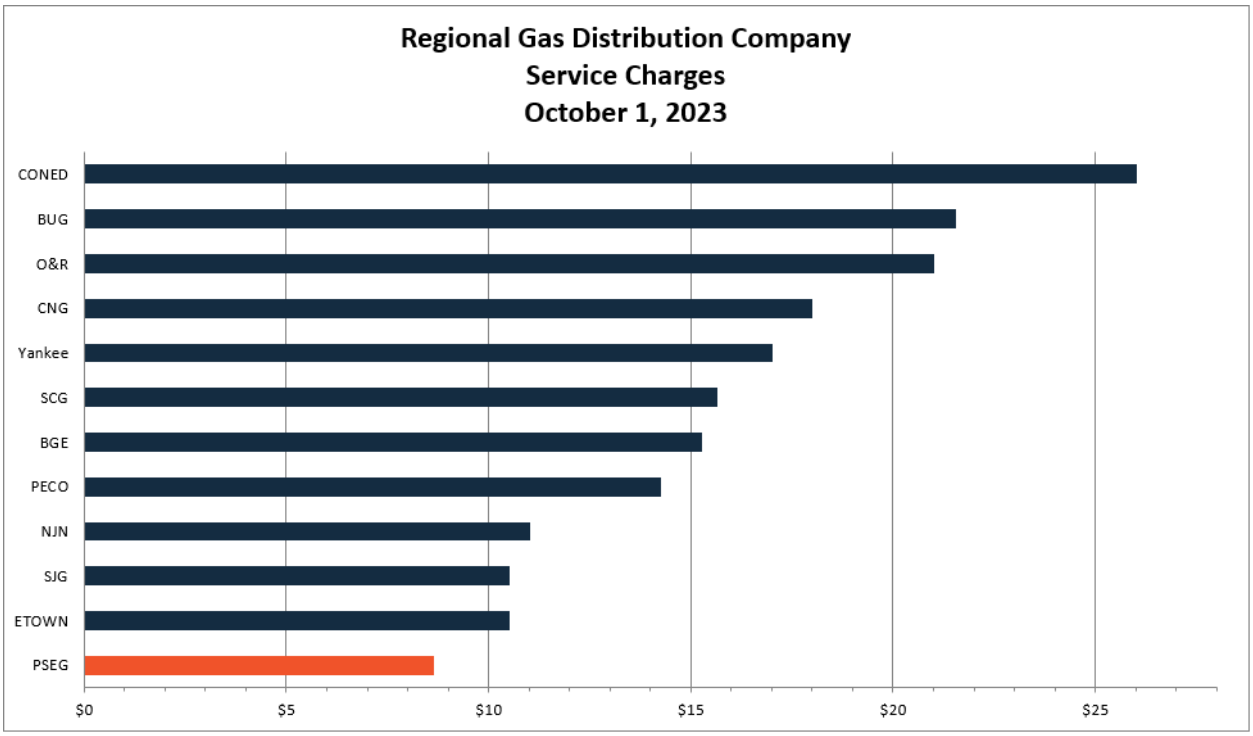


Figure 4

Q. What are the periods used for the COSSs and Rate Design that you are sponsoring in this proceeding?

A. The COSSs presented in this testimony are based upon the period of January 1 to December 31, 2022. The only variations from actual costs in the COSS period were the requested overall Rate of Return value, proposed rate base adjustments such as working capital requirements, and the proposed *pro forma* Adjustments. These adjustments, as well as the adjustments needed to synchronize the COSS results with the proposed rate design as discussed later in my testimony, and the rate design presented in this testimony are based upon the Test Year of June 1, 2023 through May 31, 2024 (hereafter "Test Year").

Q. What billing determinants will be used to determine the revenue requirement and rates that are being established in this proceeding?

A. The billing determinants used to establish rates and the revenue requirement in this proceeding will be the actual Test Year billing determinants as adjusted for normal weather. For the initial filing and any updates (prior to the final filing) with all actual data, the billing determinants will be a mix of weather normalized actual and forecasted billing determinants. Weather normalized billing determinants are calculated by adjusting actual recorded monthly gas sales to account for the effects of abnormal weather. A summary of the actual billing determinants, the weather normalized billing determinants, and the variation of each determinant from normal for the Test Year is shown in Schedule SS-G2.

Weather Normalization of Billing Determinants

Q. What weather pattern is used to weather normalize actual billing determinants?

A. The Company utilizes a twenty-year weather pattern as measured at Newark Liberty International Airport covering the period ended December 31, 2021.

Scope of the COSS

Q. Please describe the COSSs that the Company is presenting in this proceeding.

A. The Company is presenting two COSSs in this proceeding -- its recommended COSS is referred to as the "Company COSS" – and an additional COSS based on a methodology developed by BPU Staff. As discussed more fully below, the Company does not support the use of the Staff COSS to establish rates in this proceeding, but is submitting the study in compliance with the 2018 Rate Case Order. The COSSs discussed in this testimony are for the gas Distribution portion of the Company's operations. Thus the COSSs are generally "pipes only" analyses for the Company's regulated gas delivery business. They do not include the costs for the Company's

Balancing Services or BGSS because rates for those services are set in another proceeding. The impact of changes in distribution margin revenues that flow to the BGSS provider, such as those associated with Rate Schedule TSG-F, will, however, be shown as a change in the BGSS charges to customers.

Adjustments to Accounting Data

Q. Did you make any adjustments to the accounting data used in the COSSs?

A. Several adjustments to the 2022 accounting data used in the COSSs were necessary prior to its use. These adjustments and FERC Accounts associated with each of these adjustments are shown on Page 1 of Schedule SS-G3.

In the rate design process, the unit charges associated with these adjustments will be added back as appropriate in each rate schedule to assure full recovery of these expenses. The Company COSS and the Staff COSS each include these adjustments to costs and billing determinants.

COSS OVERVIEW

Introduction

Q. What is the first step in developing new gas rates?

A. The first step in developing new gas rates is the preparation of an appropriate COSS. The Company COSS was used to both separate costs by functional segments and to allocate these segmented costs to the rate classes or sub-classes based upon each class's responsibility for that cost.

Q. What is the objective of a COSS?

A. The objective of a COSS is to measure the cost responsibility of each rate class and distribution function (functionalization).

Cost Allocation Concepts

Q. Please describe the cost allocation concepts used in the Company's COSS.

A. Inherent in any COSS is the allocation to rate classes of many costs which by their nature are difficult to relate precisely to cost causation. Cost causation describes the cause and effect relationship between customer requirements, load profile, and usage characteristics, and the costs incurred by the utility to serve those requirements. Experts will differ on the best way in which many costs should be allocated among customer classes. The key is to determine which approach makes the most sense in terms of best answering the question of what caused the cost, and then to apply the result in a reasoned, balanced manner. At all times, it is important to recognize that the COSS is intended to be a guide to appropriate ratemaking, and that one objective of ratemaking is that the end result should be a reasonable one.

As I will discuss later, I have used the results from the Company COSS as a direct guide in developing rates but tempered the final rate design to provide a reasonable balance between the goal of moving each rate schedule towards costs and the goal of achieving reasonable percentage increases based upon the resulting customer impacts.

General Cost Allocation and Functionalization Methodology

Q. What is the basis for the cost allocation and functionalization methodologies used in the Company COSS?

A. In the gas distribution business, the revenue requirements related to gas mains and services far exceed all other items. Together these facilities comprise the vast majority of rate base and are the basis for much of the operations and maintenance ("O&M") expenses. As previously stated, it is important to ensure that the allocation methods used in the COSS reflect the underlying cost causation principles. Gas mains have been, and continue to be, installed to bring gas service to the

proximity of each customer's premise and are sized to handle the peak hourly gas flow at design conditions, without regard to the gas flow at any other time of day or season. These are the sole reasons and engineering basis for the design and cost of mains, and as such, the allocation of those costs should properly reflect each rate class's responsibility for the peak gas flow. Company witnesses Mike Schmid and Rick Fonseca discusses this in detail in the portion of their testimony entitled "Gas Capital Expenditures". In contrast to the cost of gas mains, the cost of a gas service (the pipe from the gas main to an individual building) is related to both the peak design loads of each building and the distance from the gas main (usually located in the street) to the structure itself. Because often one gas service serves more than one customer (or meter) in a building, the cost responsibility of a customer is a complex combination of site-specific conditions. The Company has relied on a study of actual installations of services and meters and employed that study to determine the allocation of gas service costs.

The methods of allocating the costs of mains and services used in the Company's COSS are based on sound cost causation principles and, as such, constitute a reasonable cost allocation methodology for the most significant categories of the Company's costs.

Functionalization into Five Segments

Q. What is the first step in the process to start a COSS?

A. As a first step in that process, the COSS unbundles total costs into five distinct functional segments – Distribution Access, Distribution Delivery, Street Lighting Fixtures, Customer Service, and Measurement.

Q. Once these functional segments are developed, how are they used?

A. These separate functions (or "segments") assist in the development of individual rate schedule components, such as the Service Charge. Once the plant and expenses are functionalized to the proper segment, the allocation process spreads the cost responsibility to the rate classes.

Q. What items are included in each of these segments?

A. The Distribution Access ("Access") segment includes the plant and O&M expenses related to gas services and regulators.

The Distribution Delivery ("Delivery") segment includes all equipment (plant and related O&M) from the city gate interconnections with upstream pipeline suppliers up to the point of connection with gas services, including all metering and regulation stations (the interface with the interstate gas pipelines), gas load dispatching operations, and gas mains. This segment also includes Appliance Services, recovery of regulatory assets, and the plant and non-commodity expenses related to gas production and storage facilities owned by PSE&G. Although these storage and production facilities are included in the Delivery segment, these costs are offset by the customer non-rate-related revenue received directly from the BGSS Supplier for whom these facilities are operated, as stipulated in the Gas Contracts Proceeding in Docket No. GM00080564, and thus do not affect the rates established in this proceeding.[4]

The Street Lighting segment is limited to gas street lighting lamps, posts and services.

The Customer Service segment includes all costs related to billing, inquiry, sales, service and collection activity.

[4] *See In the Matter of the Petition of Public Service Electric and Gas Company's Proposal to Transfer its Rights and Obligations Under its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and Other Relief*, BPU Docket No. GM00080564.

The Measurement segment includes the costs for meter reading, customer-related meter plant and meter O&M.

Q. Are all costs included in these five segments?

A. Yes, all costs are included in one or more of these of five functional segments.

Access Segment

Q. Please discuss how the Access segment was allocated among the Company's customers classes.

A. The Access segment is the initial link between the shared or common distribution system and the customer's own gas facilities and is comprised of the gas service line from the main in the street to the meter and regulator at the customer's building. The embedded costs for this segment were allocated across the rate classes based on a study of actual installations of gas services.

Delivery Segment

Q. Please discuss how the Delivery segment was allocated among the Company's customer classes.

A. The Delivery segment consists of the portions of the distribution system that are used to serve multiple customers and are physically connected with individual customers' service lines. Basically, this segment includes all of the gas mains in the distribution system. The embedded costs of this segment were allocated across the rate classes through a variety of direct and indirect allocators which are discussed in greater detail in Appendix G-1.

Street Lighting Fixtures Segment

Q. Please discuss how the costs were allocated to the Street Lighting segment.

A. This segment is comprised of the investment for gas street lighting lamps and poles and all associated O&M expenses for this equipment. The gas service dedicated to supplying a gas

streetlight is also segmented to this function. The costs of this segment are allocated solely to the Gas Streetlighting rate class.

Customer Service Segment

Q. Please discuss how the Customer Service costs were allocated to the Company's customer classes.

A. This segment encompasses all costs related to Customer Service type functions, such as costs related to billing, payment receipt and processing, collection activity, and other account maintenance type costs, with the exception of meter reading costs, which are included in the Measurement segment. These costs are allocated to the rate classes based upon a separate cost study of Customer Service functions.

Measurement Segment

Q. Please describe how the Measurement segment costs were allocated to the Company's customer classes.

A. This segment includes costs for meter reading and the investment and O&M expenses related to meters. Meter reading costs are allocated to the rate classes based upon a separate cost study of Customer Service functions, while the meter investment is allocated across the rate classes based upon the relative installed cost of new meters.

Modeling Procedure

Q. Please describe the Company COSS modeling procedure.

A. The Company COSS was developed based upon the weather normalized billing determinants and costs for each of the rate schedules. The revenues received by each rate class were calculated (or target balanced) such that the resulting rate of return ("ROR") for each rate class equals the Company's proposed overall ROR. Schedule SS-G4 contains the complete details

of these final COSS results. Schedule SS-G5 presents a summary report of the revenue requirements by functional segment, while Schedule SS-G6 shows the revenue requirements by function (or segment) for each rate class.

Although Rate Schedule TSG-F and its associated costs are modeled in the COSS, all distribution revenue from Rate Schedule TSG-F flows to the BGSS provider as an offset to the "Non-Gulf Coast Cost of Gas." The revenue requirements associated with Rate Schedule TSG-F must therefore be recovered from the remaining firm customers. The allocation of these revenue requirements will be discussed in detail later in the section titled "Synchronizing the Cost of Service Study to the Rate Design".

After expenses or plant investment-related costs have been entered to the model, usually by FERC account or groups of accounts, a modeling allocator is also entered which performs two functions. The allocator shows:

1. Which of the five segments, or functions, the particular plant or expense item has been attributed to, and
2. The basis on which the particular plant or expense item has been allocated across the rate classes.

The Cost of Service model starts the calculation procedure by allocating the respective plant and expense items to rate classes using an allocator that reflects the reason the cost was incurred. Rate revenues received by each rate class are then target balanced such that the resulting ROR for each rate class equals the Company's proposed overall ROR. The model continues by separating all plant and expense items into appropriate functional segments by rate class, according to the modeling allocator assigned to the particular plant or expense item. The revenue requirement

by segment for each rate class is then calculated to maintain, by rate class, the Company's proposed overall ROR used in the initial calculation.

The Direct and Indirect allocators used in the COSS and a detailed review of how all COSS items are segmented and functionalized are discussed in the Appendix G-1 to my testimony. In that Appendix, a description of how each of the major plant categories (gross plant), is segmented or functionalized is provided. The procedures used on Common and General plant, depreciation reserve, adjustments to rate base, operating revenues, O&M expenses for utility plant, administrative and general ("A&G") expenses, depreciation and amortization expenses, *pro forma* expense adjustments, and finally, taxes are also described.

Q. Please describe how the results of the Company COSS are presented in your schedules.

A. Schedule SS-G4 shows the details of how plant and expense items were separated into each of the five segments and allocated to each category of customers represented by the various rate classifications based upon the extent to which those groups of customers caused the costs. Schedule SS-G4 also shows the results of the allocation for each plant and expense item to each rate class. Schedule SS-G5 presents a high-level summary of expenses, plant, and revenue requirements for each of the five functional segments. Schedule SS-G6 is a summary report of the rate related revenue requirement, by functional segment, for each rate class in total.

The revenue requirements presented in the Company COSS do not include the revenue requirements associated with the SBC or other adjustment clauses or the revenue requirements associated with peaking plant and gas storage facilities. The costs related to the Adjustment Clauses will be collected from customers directly through the appropriate charges, and the revenue requirement associated with the peaking plant or gas storage facilities will be collected directly from the BGSS supplier.

Synchronizing the COSS to the Rate Design

Q. Please explain how the results of the Company COSS were synchronized with the proposed rate design.

A. Two adjustments are made to synchronize the results of the Company COSS to the proposed rate design. The first is an adjustment for the recovery of Rate Schedule TSG-F revenue requirements. The second is to synchronize costs because the COSS test period is different from the period used for the calculation of revenue requirements and rate design. With respect to the recovery of TSG-F revenue requirements, the Stipulation in the Gas Contracts Order, requires that all distribution revenues from Rate TSG-F must flow to the BGSS provider as an offset to BGSS gas costs, not to PSE&G. Thus, although the COSS can be used to determine the revenue requirements associated with Rate Schedule TSG-F, none of the revenue from these customers will flow to PSE&G. Instead, all distribution revenue requirements related to Rate Schedule TSG-F must be recovered from all other firm customers. The calculations to effectuate this requirement are set forth on Page 1 of Schedule SS-G7 (Cost of Service and Rate Design Sync). As indicated, the TSG-F revenue requirement is re-distributed to Rate Schedules RSG, GSG, LVG and SLG on an equal per therm of BGSS-supplied gas basis. The results of this re-distribution by functional segment are set forth on lines 15 to 20 of Page 1 of Schedule SS-G7.

In addition, as previously noted, the Company COSS is based on the period of January to December of 2022 while the Rate Design is based on the test year of June 2023 to May 2024. Thus, it is not possible to use the COSS results directly in the rate design process because the number of customers, therms transported, as well as plant and expenses are slightly different between the two time periods. To properly design rates, the COSS results must be adjusted slightly to correspond to the rate design test year period. The methodology used to synchronize the Cost of Service results is set forth on Page 2 of Schedule SS-G7. Because the primary difference is in

the number of customers and amount of gas delivered, each functional segment's revenue requirement from Schedule SS-G6 was multiplied by the ratio of either the number of customers or gas delivered for the rate design test year to the same value during the COSS test year. The revenue requirements associated with the Distribution Delivery Segment (Row 2) were adjusted by the ratio of the gas delivered in these two periods. The revenue requirements associated with the Access Segment (Row 1), Customer Service Segment (Row 4) and Measurement Segment (Row 5) were adjusted by the ratio of the number of customers in these two periods. The revenue requirements associated with the Street Lighting Segment (Row 3) were adjusted by the ratio of the number of gas streetlights between these two periods. These steps are shown on lines 1 to 15 of page 2 of Schedule SS-G7. The resulting adjusted Company COSS functionalized revenue requirements are each then adjusted on an equal percentage basis so that the total equals the proposed rate related revenue requirements as set forth on lines 16 to 25 of Page 2 of Schedule SS-G7. The final adjusted functionalized revenue requirements are used in the rate design process.

RATE DESIGN

Introduction

Q. What are your objectives for developing the proposed gas rates?

A. The proposed gas rates have been developed to meet several objectives. The primary purpose is to recover revenues equal to the revenue requirement from customers. Additionally, this recovery should be effectuated on an equitable basis that provides the correct price signals to individual customers based on the cost to serve those customers. The final objective is that rates should be simple and understandable for the customer.

Q. Are the proposed rates based solely on the results of the Company COSS?

A. No. The COSS is a guide to appropriate ratemaking; its results are not applied in strict mathematical manner to design the proposed rates. While our goal is to move rates toward a full cost basis, that goal must be balanced against the need to achieve reasonable results.

Q. Do the rates included in your testimony include or exclude New Jersey Sales and Use Tax ("SUT")?

A. The proposed rates described in the next sections of my testimony and associated Schedules exclude SUT unless specifically indicated. However, the appropriate prices both without and with SUT are, included in the Proof of Revenue by Rate Schedule in Schedule SS-G11 as well as the proposed Tariff Sheets set forth in Schedule 3 of Exhibit P-1, and all other schedules that reference rates charged to customers.

Limitations on Rate Changes

Q. Did you develop and apply limits in designing proposed rates in this proceeding?

A. Yes. In order to achieve an overall goal of designing just and reasonable rates, I apply the principle of "gradualism" to temper the rate increases indicated by the Company COSS. To apply the principle of gradualism, I developed and employed a number of limits on the size of the rate increases that are proposed.

Q. Please describe the rate increase limits used in developing the proposed gas rates.

A. The first limit is that the proposed overall percentage revenue increase will be shared, within limits, among all customer classes. Although a primary goal is to move the delivery rates for each rate class toward the cost to serve as indicated by the Company COSS, no class will receive less than 50%, nor more than 150% of the overall average percentage Distribution increase. In addition, no class will receive more than 200% of the overall average percentage bill increase.

These rate increases limits were selected to provide a reasonable balance between the goal of moving towards the cost to serve, and the need to achieve equity among customer classes. The calculation and percentage values of these limits are shown on page 1 of Schedule SS-G8 (Inter Class Revenue Allocations). For Rates RSG, GSG and LVG, any shortfall in the revenue increase (or decrease) from these limitations was transferred to these other rates based upon the magnitude of the revenue increase (or decrease) received by those rates.

Q. Are there any exceptions to the proposed limits?

A. Yes. Because the prices charged for Rate Schedules TSG-NF and CIG are not cost-based but are based upon other considerations such as value of service, the distribution component for these rates was increased by the overall distribution percentage increase to maintain the current relationship in the level of distribution charges to the level of overall Company gas distribution revenue requirements, with the exception of Rate Schedule CSG. These customers have contracted distribution charges, so only the service charges were increased.

Inter Class Revenue Increase Allocations

Q. Please describe the process for allocating the proposed distribution increase to each rate class.

A. Page 1 of Schedule SS-G8 shows the calculation of the overall average percentage increase for Distribution and total bills, as well as the calculation of the upper and lower limits to be used in the inter class revenue increase allocation on Schedule SS-G8, page 2.

Page 2 of Schedule SS-G8 shows the development of the proposed inter-class allocation of the revenue increase. The Rate Schedules are indicated in Column 1, while Column 2 is the Proposed Distribution Revenue Requirement based upon the Company COSS results that were synchronized to the rate design test year. Column 3 is the Present Distribution Revenue, while

Column 4 shows the increase that would occur if the synchronized Company COSS results were used directly, hence the use of the word "Unlimited" in the column heading. Column 5 is the present total bill revenue calculated as if all customers were supplied at BGSS rates. Column 6 is the percentage increase in distribution if the unlimited increase in dollars (from Column 4) were applied to the rates; that is, the percentage increase to each rate schedule if the COSS based increases were applied without constraints. Column 7 is the cost offsets from changes in the Margin Adjustment Clause and the BGSS charges resulting from distribution increases to Rate Schedules TSG-F, TSG-NF, CIG and CSG. The result of the proposed allocation of the Company's revenue requirement increase to the rate classes, consistent with the principles outlined in the previous section, Limitations on Rate Changes, is presented in Column 8 and Column 10. Specifically, Column 8 shows the percentage increase and Column 10 shows the proposed Distribution revenue increase by rate class. Column 9 shows the proposed total bill percentage increase if all customers were supplied at BGSS rates.

Application of these limits is somewhat complex due to the re-distribution of revenue from three sources. Rate Schedule TSG-NF distribution increases are flowed back to customers via the Margin Adjustment Charge (MAC), distribution increases applied to Rate Schedules TSG-F, CIG and CSG flow back to customers as a reduction in their BGSS rates and increases in the rates for gas supplied for pilot use for Rate Schedules TSG-NF and CIG also flow back to firm customers as a reduction in their BGSS rates. All of these credits are as shown in Column 7 of page 2 of Schedule SS-G8. In order to capture these revenue re-distributions correctly, a strict order of which calculations of the inter-class revenue increase allocations was followed.

The first step was the determination of the cost based charges for Rate Schedule TSG-F (as indicated on line 1 of page 2 of Schedule SS-G8). Because the value in Column 7 for Rate

Schedule TSG-F, the "Change in MAC and BGSS Credits" is based upon both the final outcome of the Rate Schedule TSG-F increase, as well as that for Rate Schedules TSG-NF and CIG, a value of zero was first utilized for the calculation. Once the upper and lower percentage distribution increase limits were applied (as shown in Column 8), an initial result for the Proposed Total Bill Increase Percentage (Column 9) and Proposed Distribution Revenue Increase (Column 10) was calculated.

The next step was to determine the increases for Rate Schedules TSG-NF and CIG. The Limited Final Distribution Charge Increase Percentage for Rate Schedule TSG-NF (Line 2, Column 8) was set equal to the overall average distribution charge percentage increase (Page 1, Line 8). For Rate Schedule CIG, the overall average distribution charge percentage increase was used as the Limited Final Distribution Charge Increase Percentage for Rate Schedule CIG (Line 3, Column 8).

Once the initial values for the increase to Rate Schedules TSG-NF, TSG-F and CIG were determined, the change in the MAC charge and BGSS credits could be calculated, and then applied to each of the rate schedules affected as indicated in Column 7. The change in the MAC charge used in this schedule relates only to the change in Rate Schedule TSG-NF margins, and does not include a change in the MAC charge due to current over/under recoveries.

The final step was to calculate the proposed distribution revenue increases for Rate Schedules RSG, GSG and LVG. These calculations were done in the same manner as performed for Rate Schedule TSG-F discussed above, although at this stage, the MAC and BGSS credits (in Column 7) had been calculated. These calculations and the application of the limits were performed in an Excel spreadsheet utilizing the "Goal Seek" function in order to meet all of the

requirements of the limits and to properly allocate any revenue shortfall between these four rates, while recovering the full requested increase in distribution revenue.

Q. How should the rate design be affected if the Board approves an amount other than the Company's overall revenue increase request?

A. If the Board approves an amount other than the Company's overall revenue increase request, the increase to each of the classes should be allocated in proportion to the proposed revenue increase shown in Column 10, Page 2 of Schedule SS-G8.

General Rate Design Principles and Methodology

Q. Please describe the general rate design principles and methodology used in developing the proposed gas rates.

A. The rate design methodology presented in this testimony follows the philosophy of the cost allocation methodology used in the Company COSS. The rate design aligns, as close as practical, the rates (prices charged to customers) with the customers' underlying costs.

Changes in the distribution rates for Rate Schedules TSG-F, CIG, CSG and changes in the charges for pilot use for Rate Schedules TSG-NF, and CIG and CSG are cost offsets to the BGSS rates, and the resulting proposed BGSS tariff sheets have been modified appropriately (as indicated in Schedule 5 of the transmittal letter and in Schedule SS-G12).

The Service Charges for Rate Schedules RSG, GSG, LVG and TSG-F were set to move towards the revenue requirements indicated in the Company COSS for the sum of the Access, Customer Service, and Measurement segments. Except for the Residential Service Gas (RSG) Rate Class, which is discussed in the rate class specific changes portion of my testimony, the change in the Service Charges was limited to the same general inter rate class limits of no more than 150% of the overall average Distribution percentage increase. The proposed Service Charges on Rate Schedules TSG-NF and CSG were set equal to the Service Charge on Rate Schedule TSG-

F and the Service Charge for Rate Schedule CIG was increased in an amount equal to the overall average distribution percentage increase.

These limits were selected to provide a reasonable balance between the goal of moving each rate component towards costs, and the goal of achieving reasonable bill impacts. Any shortfall in Service Charge revenue resulting from these limitations was transferred to the remaining Distribution Charges of each rate schedule. In general, the Distribution Charges for each Rate Schedule were set to recover all the revenue requirements of the Distribution Delivery segment, plus any shortfall created from limitations in the proposed Service Charges. The calculations of the proposed Service Charges are found on Schedule SS-G10.

RATE SCHEDULE SPECIFIC CHANGES

Rate Schedule Residential Service Gas ("RSG")

Q. Please describe the rate design for Rate Schedule RSG.

A. Currently, Rate Schedule RSG is below its cost to serve. In addition, as indicated in Schedule SS-G9 Service Charge Calculations, (line 2), the Company COSS indicates that an increase in the monthly Service Charge is warranted, while the current Distribution Charge per Therm is above cost. Therefore, the Company proposes to increase the service charge corresponding to Service Charge limits discussed earlier. This will ensure that the Service Charge and Distribution Charge per Therm rate, will continue to move closer to the cost to serve.

The Distribution Charge for the Special Provision for Off-Peak use has been set at one-half the normal Distribution Charge. This is a continuation of the practice to provide a reasonable balance between providing the correct price signals to customers with gas air conditioning, while providing some contribution to offset winter peak period costs (and thus rates). No changes are proposed for qualification for this Off-Peak provision.

The results of the Rate Schedule RSG rate design appear on page 5 of the Proof of Revenue in Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule. The calculation of the annual gas commodity cost utilized in the Proof of Revenues for this and all other rate schedules is based upon all customers purchasing gas on the appropriate BGSS service as presented in Schedule SS-G10. The magnitude of the BGSS values remain constant in both sides in the Proof of Revenue (Schedule SS-G11) and their inclusion allows the proposed rate changes to be viewed in the context of a customer's overall bill.

The calculation for the changes in the MAC clause resulting from the change in flow back from the TSG-NF rates is included in Schedule SS-G8. Typical residential customer bill impacts as a result of these changes are shown on page 1 and 2 of Schedule SS-G12.

Rate Schedule General Service Gas ("GSG")

Q. Please describe the rate design for Rate Schedule GSG.

A. The Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments utilizing the previously discussed limits as shown in Schedule SS-G9.

The Distribution Charge was set utilizing the balance of the Proposed GSG Distribution Revenue Increase from Schedule SS-G8.

As with Rate Schedule RSG, the Distribution Charge for the Special Provision for Off-Peak use has continued to be set at one-half of the normal Distribution Charge. This continues the practice of providing a reasonable balance between providing the correct price signals to customers with gas air conditioning, while providing some contribution to offset winter peak period costs (and thus rates). No changes are proposed for qualification for this Off-Peak provision.

The results of the Rate Schedule GSG rate design are shown on page 7 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule. The typical customer bill impacts as a result of these changes are shown on page 3 and 4 of Schedule SS-G12.

Rate Schedule Large Volume Gas ("LVG")

Q. Please describe the rate design for Rate Schedule LVG.

A. Similar to what was done for Rate Schedule GSG, the LVG Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments utilizing the previously discussed limits as shown in Schedule SS-G9.

The Distribution Charges and Demand Charge were set to recover the balance of the revenue requirements. As I have previously discussed, the majority of gas distribution related costs are relatively fixed, and do not vary with the monthly volumes of gas transported.

In order to meet the rate design goals outlined at the start of this Section of my testimony, and to prevent unintended customer migration between Rate Schedules GSG and LVG, the Rate Schedule LVG rate maintains the existing rate design principle that a bill for a 12,000 therm per year customer be approximately the same for Rate Schedules GSG and LVG. With this in mind, the demand charge was set to recover the same percentage of the distribution revenue as currently. The block one and block two charges were then calculated to uniquely recover the balance of the Rate Schedule LVG revenue requirements and maintain LVG/GSG bill neutrality at 12,000 therms per year, distributed on the monthly usage pattern of the average GSG customer.

The results of the Rate Schedule LVG rate design are shown on page 9 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule.

Information on the typical customer bill impacts as a result of these changes is indicated on page 5 and 6 of Schedule SS-G12.

Rate Schedule Street Lighting Gas ("SLG")

Q. Please describe the rate design for Rate Schedule SLG.

A. The Company proposes to increase the Distribution Charge per Therm to its cost to serve as determined by the COSS.

The balance of the revenue requirements will be recovered from the luminaire charge, and the prices for individual gas streetlights will be updated but limited by the overall rate impact limitations I have previously discussed.

The results of the Rate Schedule SLG rate design are shown on page 13 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Transportation Service Gas – Firm ("TSG-F")

Q. Please describe the rate design for Rate Schedule TSG-F.

A. This rate remains closed except to existing customers. The Service Charge was set to move towards the Company COSS results to recover the revenue requirements for the Access, Customer Service and Measurement segments while applying the previously discussed limits as shown in Schedule SS-G9. The balance of the revenue increase is proposed to be recovered proportionally from the volumetric Distribution Charge and the Demand Charge. The results of the Rate Schedule TSG-F rate design are shown on page 15 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Transportation Service Gas – Non Firm ("TSG-NF")

Q. Please describe the rate design for Rate Schedule TSG-NF.

A. The Service Charge for TSG-NF has been set equal to the new Service Charge proposed for Rate TSG-F, the calculation of which is shown on Schedule SS-G9. The charge for gas used for pilots during an interruption is proposed to be increased, based on the highest monthly price for gas service on Rate Schedule GSG, including balancing charges and gas supply service on BGSS-F, that occurred in the prior 36 month period.

Special Provision (a) has been modified to add penalty language if a customer does not provide an alternative fuel capability affidavit by November 1st.

The results of the Rate Schedule TSG-NF rate design are shown on page 17 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Co-Generation Industrial Gas ("CIG")

Q. Please describe the rate design for Rate Schedule CIG.

A. This rate remains closed except to existing customers. Because the Service Charge was never based on cost, it was increased by the overall average Distribution percentage increase.

The Company proposes to modify the margin component of the rate so that the net of all of the adjustments to the Estimated Average Commodity Cost per therm that are used to determine the price paid by customers is increased by the overall average Distribution percentage increase. The differential charge for the two usage blocks of Rate Schedule CIG, usage less than 600,000 therms per month and usage in excess of this amount, has been kept at the same one cent per therm differential that currently exists.

The results of the rate design are shown on page 11 of Schedule SS-G11. The general format of the calculations is described on the first page of that Schedule.

Rate Schedule Contract Service Gas ("CSG")

Q. Please describe the rate design for Rate Schedule CSG.

A. The Service Charge for CSG has been set equal to the new Service Charge proposed for Rate TSG-F, the calculation of which is shown on Schedule SS-G9. Because the distribution charge for CSG customers is not based on cost the majority of customers on this rate class will receive no change in their per therm distribution rate with the exception of those that are contracted to have their charges adjusted during base rate proceedings.

TARIFF CHANGES

Q. Are you proposing any further changes to the proposed tariff?

A. Yes. Please refer to the Guide to Gas Tariff Changes, Exhibit P-1 Schedule 4.

TAX ADJUSTMENT CREDIT ("TAC")

Q. Please briefly describe the TAC Mechanism.

A. The TAC mechanism was established in the 2018 Rate Case Order, to flow back certain tax benefits to customers.

Q. Please briefly describe PSE&G's proposed TAC adjustments.

A. As described in more detail in the testimony of Mr. Pardo, the Company is proposing the following adjustments to the TAC:

1) In addition to continuing to flow back the benefit of the historic Safe Harbor Adjusted Repair Expense ("SHARE") deduction, the Company proposes to flow back to customers the net federal tax benefit associated with the historical Mixed Service accumulated deferred income taxes ("ADIT") balance over approximately five years.
2) The Company proposes to add the current Mixed Service deduction net benefit to the current SHARE deduction net benefit already included in the TAC, but both at a pre-

determined, fixed annual amount, with any excess to be flowed back to customers in a subsequent rate case; and

3) To better match the seasonal flow of Company pre-tax income, the Company began to amortize the monthly flow back of excess deferred income taxes ("EDIT") and SHARE on a seasonal basis in the 2023 TAC filing to match pre-tax income as described in the 2023 TAC cost recovery proceeding. In this proceeding, the Company is aligning the return calculation with the seasonal amortization methodology.

Q. Does the Company have an amortization schedule for the proposed amortizations?

A. Yes, the proposed amortizations are included in summary format in rows 167-170 in worksheet 'RevReq-G' of WP-SS-TAC-1.xlsx for 2025 through 2028.

Q. How does the Company propose to modify the TAC revenue requirement formula based upon the changes discussed previously?

A. The TAC revenue requirement formula is calculated monthly and will be modified with the ***bolded items*** below:

TAC Revenue Requirement = (Amortization of Protected ADIT Balance +(Amortization of Historic SHARE ADIT) Balance + ***(Amortization of Historic MSC Deduction ADIT Balance*** *+ After-tax Return on Cumulative Historic SHARE Deduction ADIT Change +* ***After-tax Return on Cumulative Historic MSC Deduction ADIT Change*** *+* ***Pre-set*** *SHARE Deduction Flow-Through +* ***Pre-Set MSC Deduction Flow-Through*** *+ IRS Audit Electric Adjustments + Other Major Gas Tax Adjustments) * Gas Revenue Factor*

See Schedule SS-TAC-2G for the monthly net revenue requirement calculations.

Q. What is the TAC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The gas net revenue requirement for the initial 16-month period of September 1, 2024 through December 31, 2025 is a credit to gas customers of $252.6 million or $197.8 million on an annualized basis. See Schedule SS-TAC-1.

DISTRIBUTION ADJUSTMENT CHARGE AND STORM RECOVERY CHARGE ("SRC")

SRC Mechanism

Q. Please briefly describe the Company's proposed SRC.

A. As described in the testimony of Mr. McFadden, the Company is proposing a SRC to:

1. Recover the deferred major storm costs that have been incurred since 2018 with interest.
2. Defer and then recover future major storm costs, including interest, through subsequent true-up filings.

Q. Please describe the methodology used to calculate the SRC recovery.

A. The Company is proposing a new Distribution Adjustment Charge ("DAC") clause in its gas tariff with the SRC as a new component of the DAC. The DAC was proposed by the Company in its COVID-19 cost recovery filing where COVID-19 Recovery Charge would also be a component of the DAC. The details of the SRC and the recovery mechanism are described below. The following formula describes the SRC mechanism:

SRC Balance = Prior Month SRC Balance – SRC Revenue + Incremental Deferred Major Storm Costs + Interest Expense

Q. How will the SRC be charged or refunded to customers?

A. The Company proposes to charge or refund the SRC through a new component of the Company's proposed DAC in the Company's gas tariff. The charges will be applied to each therm of a customer's usage and will apply to all gas customers.

SRC Components

Q. What is the Initial SRC Balance?

A. The Initial SRC Balance is the total incremental deferred major storm costs associated with major storms since the Company's last Base Rate Case in 2018 prior to the implementation of the SRC rate.

Q. What are the "Incremental Deferred Major Storm Expenses?"

A. The Incremental Deferred Major Storm Costs are those monthly costs that occur after the implementation of the SRC rate.

Q. What is the "Interest Expense?"

A. The Interest Expense is the monthly carrying costs related to the SRC Balance. It is calculated as following ((Prior Month SRC Balance + (– SRC Revenue + Monthly Activity + Prior Month SRC Balance)) / 2) x (Annual Interest Rate / 12). In calculating the Interest Expense, the annual interest rate is based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines utilized in the preceding month. If both commercial paper and bank credit lines have been utilized, the weighted average of both sources of capital shall be used. In the event that neither commercial paper nor bank credit lines were utilized in the preceding month, the last calculated rate will be used. The interest rate shall not exceed PSE&G's overall rate of return as authorized by the Board as utilized in calculating revenue requirements for the corresponding period. The calculation of the monthly interest can be found in Schedule SS-SRC-1G, Page 1.

Q. How does the Company propose to calculate the initial SRC Rate?

A. The Company proposes to set the initial SRC Rate to recover these costs over a three- year period including interest. The rate will be a rate applied to all gas customers where applicable. See Schedule SS-SRC-1G, Page 2 for the calculation.

Q. When does the Company propose to submit subsequent SRC filings to change the SRC?

A. The Company plans to submit a periodic SRC filing to change the SRC rate if warranted based upon the projected SRC over/under balance.

Q. When will storm costs be reviewed for prudency?

A. The Company proposes that all storm costs will be reviewed as part of subsequent SRC filings.

Q. When is the initial implementation of the SRC anticipated to occur?

A. The SRC is proposed to be effective September 1, 2024 corresponding to the change in base rates as a result of this proceeding. If the Board approves new base rates earlier or later than September 1, 2024, the initial rate period and corresponding rate will be adjusted accordingly from the effective date of the Board Order.

Q. What is the SRC amount for the initial period after base rates are projected to take effect in this proceeding?

A. The gas net revenue requirement for the initial annual period of September 1, 2024 through August 31, 2025 is a charge to gas customers of $1.3 million. See Schedule SS-SRC-1G.

GAS BAD DEBT RECOVERED VIA THE SBC

Q. Is the Company proposing to change the recovery method of gas bad debt expenses currently recovered from customers?

A. Yes. As described in the testimony of Mr. McFadden, the Company is proposing to change the recovery method of its gas bad debt expenses.

Q. What is PSE&G's proposal in this proceeding?

A. Consistent with my testimony in the COVID-19 proceeding, the Company proposes that gas bad debt expenses be recovered through a new Social Programs component of the Gas SBC,

consistent with the recovery of electric bad debt expense via the Social Programs component of the Electric SBC.

Q. Please describe the calculation method of Social Programs component of the Gas SBC and how it will be collected from customers?

A. The proposed Social Programs component of the Gas SBC will be calculated in a manner almost identical to the Social Programs component of the Company's Electric SBC. Schedule SS-SBC-1 contains the proposed rate calculation that will be effective concurrent with the effective date of the proposed base rates. This rate will be applicable to gas customers who currently pay the Gas SBC. Schedule SS-SBC-2 calculates the Over / (Under) Balances based upon the monthly revenue collected and gas bad debt expense. Interest calculated on the accumulated balance will be calculated identical to the method used to calculate interest for the Social Programs component of the Electric SBC, calculated monthly and added to the accumulated balance at end of each rate period. The interest rate will used will be the 2-year Treasury Bill rate plus 60 basis points, updated every August 1st each year. Schedule SS-SBC-3 calculates the annual forecasted revenue by rate schedule for the initial period commencing with the implementation of the proposed base rates.

STAFF COSS METHODOLOGY

Q. Please explain why you are submitting the Staff COSS.

A. As part of the 2018 Rate Case Order, the Company agreed to perform a COSS in the manner prescribed by Staff in the Company's next rate case. The Staff COSS and the summary of the resulting functional revenue requirements by rate class has been submitted herein with the Company's current proposed rate case filing.

Specifically, Schedule SS-G13 contains the Details of the complete Staff COSS, Schedule SS-G14 is the Summary Report by Functional Segment based on Staff's Method, and Schedule SS-G15 is the Functional Cost Summary of the COSS results based on Staff's Method.

In the Stipulation that resolved the 2018 Rate Case, the parties made it clear that they were not agreeing that the Staff COSS was appropriate, was consistent with cost causation principles, or would be a useful guide in determining just and reasonable rates. Specifically, the Stipulation stated (at 11-12):

> All parties will be free to submit any number of alternative cost of service methodologies for the Board's consideration in future cases. The Company and any Signatory to this agreement will have the right to file and support any COSS method it considers appropriate.[5]

Q. Does the Company believe that the Staff COSS provides a reasonable foundation for establishing just and reasonable rates in this proceeding?

A. No. The Staff COSS Methodology is not an appropriate methodology to use to establish just and reasonable rates because it does not achieve a result that is tied to cost causation. Instead, the Staff COSS goes to extraordinary and convoluted lengths to allocate and functionalize costs away from residential customers and onto the shoulders of commercial and industrial customers. While it may be reasonable to moderate the level of increase to be borne by residential customers, the vehicle for doing so should not be an COSS that arbitrarily transfers costs to businesses operating in the Company's service territory. The Company has taken reasonable steps to moderate the level of increase in rates for Rate Schedules RSG and GSG customers with its gradualism-based recommendations that limit the amount of increases for those classes.

The "Average and Excess" methodology underlying the Staff COSS has existed for many years. Historically this method was used to allocate costs of electric generation plant and gas production facilities where, arguably, there is an energy investment component beyond that necessary to provide capacity at the time of peak load. However, there is no evidence that costs for Public Service's gas distribution service business are caused for such reasons. It is beyond

[5] 2018 Rate Case Order at Stipulation ¶ 25.

dispute that the Company's existing design criteria is based solely on peak demand. Thus, the Staff COSS has no relationship to actual distribution plant costs or operations. As testified to by Mr. Schmid in this case, the distribution planners and designers plan and install facilities to meet the peak demands of customers – not based on the amount of energy (in therms) they consume.

The fundamental error in the Staff COSS is that there is no relationship at all between the amount of gas a pipe can carry, its diameter, and any split between a demand and energy cost classification. Determining an energy/peak classification based on the physical nature of natural gas and the pipe it flows within is unrelated to determining the cost of providing gas distribution service. Just because equipment such as gas main delivers energy, such as a gas main, it should not be classified as energy-related unless the amount of energy, other than peak energy, had some basis in the design. Gas mains have been, and continue to be, installed to bring gas service to the proximity of each customer's premise and are sized to handle the peak hourly gas flow at design conditions, without regard to the gas flow at any other time of day or season. These are the sole reasons and engineering basis for their design and cost, and as such, the allocation of these costs should properly reflect each rate class's responsibility for the peak gas flow.

Subsequent Base Case Requirements

Q. Do you believe that the Company should be required to complete the Staff COSS in subsequent base rate case filings?

A. No. The Company is requesting that this requirement not be included for the filing of its next base rate case.

Q. Does this conclude your direct testimony?

A. Yes. It does.

APPENDIX G-1 - DETAILED REVIEW OF COST OF SERVICE STUDY

Schedule SS-G4 shows the details of the Cost of Service Study used to develop distribution revenue requirements by rate schedule. This study was used in the development of the proposed rates and the following discussion is limited to this analysis. These results are summarized by revenue requirements for each rate schedule and by segment in Schedule SS-G6.

The study, as previously mentioned, is based on weather normalized costs and billing determinants for the 12 month period ending December 31, 2022, and is limited to the gas delivery business.

ALLOCATOR NAMING CONVENTION

For consistency and simplicity of bookkeeping, a naming convention has been developed for the modeling allocators.

Direct Allocators

All modeling allocators that end in a dash and a number (such as "PEAKHOUR-03") are direct allocators, meaning that:

1. The word portion of the direct allocator denotes the types of external constant or value used to allocate the plant or expense item as indicated by the name of the modeling allocator. For example, the "PEAKHOUR" denotes the Coincident Peak Hour demand of the entire system observed at the City Gate, and
2. The number portion of the direct allocator denotes the segment to which the plant or expense item is functionalized. For example, the "03" in "PEAKHOUR-03" denotes segment number 3. The business segment numbering method used in our analysis is as follows:

Segment #2 - Distribution Access

Segment #3 - Distribution Delivery

Segment #4 – Street Lighting Fixtures

Segment #5 - Customer Service

Segment #6 - Measurement

Note that labels for Segments #1 is not used.

Indirect Allocators

All modeling allocators that do not end in a dash and a number (such as A&GEXP) are indirect allocators, meaning that they will both segment and allocate costs in the same proportion as other individual or group of plant or expense items. The names of these modeling allocators are an indication of the basis upon which this allocation and functionalization process takes place.

ALLOCATION DETAILS

Intangible Plant

Gas intangible plant (Accounts G301 to G303) was not included in the study

Production Plant

All production plant (Accounts G304 to G320 on Schedule SS-G4, page 4, line 26) was determined to be related to wholesale balancing services and thus segmented to the Distribution Delivery segment and allocated on the basis of the total balancing therms for each rate schedule. This allocator (BALANCE-04) is the same allocator used throughout the Cost of Service model for all production plant assets and expenses, as well as the revenue received from the BGSS Supplier for the operation of these facilities.

Storage Plant

Storage plant (Schedule SS-G4, page 4, line 30 to 33) is treated in the same manner as production plant because it relates to balancing services. Therefore, Storage plant is segmented to Distribution Delivery and allocated on the basis of balancing therms.

Transmission Plant

All of transmission plant (Accounts G365 to G369 on Schedule SS-G4, page 4, lines 35 to 40) was determined to be related to the Distribution Delivery segment. A majority of this plant is for large gas pipes (transmission mains), which are classified as transmission mains rather than distribution mains in accordance with federal and state regulations generally due to the high operating pressure and larger size. Since these facilities perform the same type of function as distribution mains, the plant has been treated in an identical manner to that of distribution mains and allocated to the rates based upon each class's share of the amount of gas transported at the system design peak hour.

Distribution Plant

In the regulated gas distribution business determining cost causation for the revenue requirements related to gas mains and to gas services is one of the most important issues because together these facilities comprise the vast majority of rate base and are the basis for much of the operations and maintenance expenses. The majority of Distribution Plant (Accounts G374 to G388 as shown on Schedule SS-G4, page 5, line 46, to page 6, line 119) has been functionalized to four primary segments – Distribution Delivery, Distribution Access, Street Lighting Fixtures and Measurement. The plant related to Land and Structures (Accounts G374 and G375) is related to local Distribution operations field offices, and was functionalized and allocated in the same proportion as

Distribution plant in total. Gas mains have been functionalized to the Distribution Delivery segment, gas services and house regulators to the Distribution Access segment, meters to the Measurement segment, and all gas street lighting related equipment to the Street Lighting Fixtures segment.

After the functionalization was completed, each account was then examined to determine the proper allocation across rate classes. Investment for Gas Services (G380), Gas Meters (G381, G382, G385), and House Regulators (G383, G384) was then allocated to Rate Schedules RSG, GSG and LVG. This was based upon a study of actual customer installations and using the results as the basis for determining the relative investment for all customers. For the reasons that I have previously discussed, the investment for Gas Mains (Account G376) was allocated to all classes on the basis of each class's share of the amount of gas transported at the system design peak hour.

The investment in Compressor Station Equipment (Account G377) is generally determined to be related to the natural gas refueling stations located at several Public Service locations that are utilized to fuel the natural gas cars and trucks used by the Company. Any costs in this account shall be segmented to Distribution Delivery and allocated in the same manner as total Distribution Plant other than meters. All Street Lighting Facilities (G387) including the services, posts, and heads were directly assigned to Rate SLG.

Other Distribution Plant

The plant associated with Asset Retirement Obligations (booked in Account G388) relates almost exclusively to gas mains, and therefore was functionalized and allocated in the same proportion as gas mains.

General, Common and Other Plant

An accounting code, or Business Code, associated with the actual gross plant balances indicating the department to which the plant is assigned was used to segment both the general (Accounts G389 to G399) and common (Accounts C303, and C389 to C399) plant account items (Schedule SS-G4, page 4 for C303 and page 7 for general and common). Each Business Code was then grouped by function to be allocated based on cost causation. For example; a Description for office furniture and equipment was added to the Customer Service segment and allocated in the same proportion as all Customer Service activities. In other cases, where some of the facilities, such as vehicles, etc. used by the Customer Operations Department are shared between groups that are responsible for meter reading and those that provide general customer service (collections, phone inquiry, walk-in payment centers, etc.), these investments were further split in the Cost of Service Study between the Measurement segment and the Customer Service segment based on the proportion of work performed by each group. In general, all general and common investments were allocated to the rate schedules in the same proportion as the overall respective plant accounts for each segment. Items for which no reasonable functionalization could be determined were classified as "unassigned" and allocated in the same proportion as its associated plant account. In other words, unassigned general plant followed general plant and unassigned common plant followed common plant (general plant is shown on Schedule SS-G4, page 7 line 94 to line 102; while common plant is on Schedule SS-G4, page 7 line 105 to line 112).

Depreciation Reserve

The depreciation reserve associated with Accounts G300 to G399 was segmented and allocated in the same proportion as its associated plant account (Schedule SS-G4, page 8, line 1 to page 10, line 114).

Adjustments to Develop Rate Base

Adjustments to net plant used to develop Rate Base consist primarily of working capital and deferred taxes for the distribution utility. The underlying components of working capital were analyzed and segmented according to their individual use. Working capital requirements associated with Material and Supplies were allocated and segmented in proportion to the total plant, other than General and Common. Working capital requirements associated with Cash and Prepayments & Working Funds were allocated and segmented in the same proportion as the total of O&M and capital additions (essentially cash outlays) through the use of the allocator termed "EXPENDITURES". Deferred taxes were segmented and allocated in proportion to the related plant values. These adjustments are indicated in Schedule SS-G4, page 11, lines 1 to 37.

Operating Revenues

The values indicated in Schedule SS-G4, page 2, line 52 entitled "Rate Revenues from Customers" are the portion of the total target balanced revenue requirements that are necessary to be recovered from rate-related revenues (from service charges, distribution charges, minimum charges, etc.) at the proposed overall ROR, plus the increases in non rate-related revenues.

The effects of other non-rate-related revenues are booked to Accounts G487 to G495 and are shown in Schedule SS-G4, page 12, lines 9 to 19. The primary sources of these other revenues, booked in Account G488, are Competitive Services. These services have been segmented to the Distribution Delivery segment and allocated back to the customer rates from which the revenue was received, and Peaking Services (revenue from the BGSS Supplier for the operation of the peaking facilities), which constitutes the majority of the revenue booked in Account G495 and is segmented to Distribution Delivery and allocated based on balancing therms.

Production Expenses

Similar to the production plant items, all production expenses (Accounts G710 to G745 on Schedule SS-G4, page 13, lines 4 to 6) relate to wholesale balancing services and are segmented to Distribution Delivery and allocated on the basis of balancing therms, consistent with the methodology used for Production Plant.

Gas Supply Expenses

Although booked to Other Gas Supply Expenses - Account G813, any costs charged herein, relate to the operation of the Gas Systems Operations Center (GSOC) and thus are related to gas dispatching. Therefore, any costs in this Account shall be segmented to the Delivery segment and allocated on the basis of total therms delivered. This is shown on Schedule SS-G4, page 13, line 18.

Other Storage Expenses

The costs associated with the operation and maintenance of Company owned storage facilities (Account G840-G843 on Schedule SS-G4, page 13, lines 22 to 25) are treated in the same manner as production plant and segmented to Distribution Delivery and allocated on the basis of balancing therms.

Transmission and Distribution O&M Expenses

O&M expenses for transmission and distribution (Accounts G850 to G894 on Schedule SS-G4, page 13, line 28 to page 14, line 68) were generally segmented and allocated in the same proportion as their associated plant account(s) with the exception of Customer Installations expense (Account G879) which was allocated to the rates based upon an analysis of the customers for which that work was performed.

Customer Accounts, Service and Sales Expense

Expenses from a wide range of customer contact activities are booked to Accounts G901 to G916. A separate analysis was performed on the costs charged to each of these accounts to determine the best functionalization fit. The details of this account-by-account functionalization can be found on Schedule SS-G4, page 14, line 73 to page 15, line 108. The costs in each of these accounts related to meter reading were segmented to the Measurement segment and allocated on the basis of the costs to read meters for each rate class; the portion related to billing was segmented to the Customer Service segment and allocated on the relative costs of billing by rate class; the portion related to account maintenance activities (including answering general questions, setting up new accounts, remittance processing, and collection activities) was segmented to the Customer Service segment and allocated on the relative costs of performing these activities by rate class; and the portion of these expenses related to general regulated utility responsibilities was segmented to the Distribution Delivery segment and allocated on the relative costs of performing these activities by rate class. The portion of Customer Records and Collection costs (Account G903 and G905) associated with costs to disconnect customers for non-payment of bills (and their eventual reconnection) were segmented to the Customer Service segment and allocated based upon the number of customers.

Energy Efficiency and Renewable Energy expenses, a component of the SBC, normally recorded in Account G908 were not included in this analysis as discussed earlier in this testimony and as indicated on page 1 of Schedule SS-G3.

Administrative and General (A&G) Expenses

Administrative and General Expenses (Accounts G920-935) include a mix of expenditures, which were analyzed separately to determine the best functionalization fit. The details of this item-by-item functionalization can be found on Schedule SS-G4, page 15, lines 115 to 132.

An adjustment was made to the A&G expenses for G923 and G926 to separate those costs associated with the Gas Peaking Plants and to segment them to the Distribution Delivery segment. These costs were then allocated on the basis of balancing therms, similar to the method applied to other gas production related investment and expenses.

Depreciation and Amortization Expenses

All depreciation and amortization expenses were segmented and allocated in the same proportion as their associated plant accounts (Schedule SS-G4, page 17, lines 1 to 27).

Taxes Other Than Income Taxes

Other non-income type taxes were allocated based on their relationship to other plant and expenses, as indicated on Schedule SS-G4, page 18, lines 4 to 12.

Pro Forma Expense Adjustments

The pro forma adjustments the Company is proposing are summarized in Schedule MPM-29 and detailed as Adjustments #1 to #24 in Schedules MPM-30 through MPM-53 of Mr. McFaddens' direct testimony in this proceeding. Those adjustments are included in this section of the Cost of Service Study on Schedule SS-G4, page 18, lines 16 to page 19 lines 57, with the exception of the pro forma adjustments discussed below.

One specific adjustment, Pro Forma Adjustment #11 Schedule MPM-29 adjusts revenue related to the switching between Rate Schedules TSG-NF and LVG. The Company currently

retains a portion of the margins from gas service to new TSG-NF customers that commenced after the Company's base rate cases in 2001 and 2005, in accordance with the Settlements and Board Orders in Docket Nos. GR01050297 and GR05100845. Also, the Company retains the margins (total revenue less commodity revenue, SUT, SBC, and GPRC) from customers who switch from Rate Schedule LVG to TSG-NF. Conversely, the margins from customers who switch from TSG-NF to LVG are credited to the Margin Adjustment Charge (MAC) in lieu of being retained by the Company. The balance of the margin is credited to the MAC. These retained amounts are reset to zero in each succeeding base rate case. Therefore, this adjustment decreased operating income in the amount of $748,205.

Each pro forma adjustment included in the Cost of Service Study was segmented and allocated in the same proportion as the associated plant or O&M account(s). The Cost of Service modeling of Pro Forma #3 associated with Interest Synchronization, Pro Forma #5 associated with Gas COLI Interest Expense, and Pro Forma #7 associated with Gains and Losses on Sales of Property all include the added tax effects on revenue requirements as an additional expense. Those pro forma adjustments excluded from the Cost of Service Study are as follows:

- Adjustment #6- Weather Normalization Adjustment (Schedule MPM-29) is a weather normalization of operating revenues. The Cost of Service Study is already based on weather normalized costs and usage, and no further adjustment is required.
- Adjustment #11 – TSG-NF Margin Sharing (Schedule MPM-29) is related to the elimination of margin sharing revenue associated with capital investment made for TSG-NF customers since the last base case. Because these investments are already included in the proposed Rate Base, the revenue requirements related to these investments are already included in the Cost of Service Study.

Taxes

All Taxes and Tax Deductions were segmented and allocated in the same proportion as their associated plant or O&M account(s). Details of these allocations are indicated from pages 20-25 of Schedule SS-G4.

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 30 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also

contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	TBD	written	Dec-23	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E/G	QO23120874	written	Dec-23	Clean Energy Future - Energy Efficiency II Program
Public Service Electric & Gas Company	E/G	G018101112 and EO18101113	written	Nov-23	Clean Energy Future - Energy Efficiency Extension 2 Program
Public Service Electric & Gas Company	E	ER23110783	written	Nov-23	Infrastructure Advancement Program (IAP) - First Roll-In
Public Service Electric & Gas Company	E/G	ER23050273	written	Nov-23	Energy Strong II Program (Energy Strong II) - Fifth Roll-In
Public Service Electric & Gas Company	E/G	ER - 23090634 & GR - 23090635	written	Sep-23	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	GR23070448	written	Jul-23	COVID-19 Filing
Public Service Electric & Gas Company	E/G	ER23070423 & GR23070424	written	Jul-23	Green Programs Recovery Charge (GPRC)-Including CA, EEE, EEE Ext, S4A, SLII, S4AE, SLIII, EEE Ext 2, S4AEII, EE2017, and CEF-EE
Public Service Electric & Gas Company	E	ER - ER23060412	written	Jul-23	SPRC 2023
Public Service Electric & Gas Company	G	GR23060330	written	Jun-23	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR23060332	written	Jun-23	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E	ER23050273	written	May-23	Energy Strong II Program (Energy Strong II) - Fourth Roll-In
Public Service Electric & Gas Company	G	GR23030102	written	Mar-23	Gas System Modernization Program III (GSMPIII)
Public Service Electric & Gas Company	E	ER23020061	written	Feb-23	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	E/G	GR23010050	written	Jan-23	Remediation Adjustment Charge-RAC 30
Public Service Electric & Gas Company	E/G	GR23010009 and ER23010010	written	Jan-23	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22120749	written	Dec-22	Gas System Modernization Program II (GSMPII) - Eighth Roll-In
Public Service Electric & Gas Company	E/G	ER22110669 & GR22110670	written	Nov-22	Energy Strong II Program (Energy Strong II) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER22100667 & GR22100668	written	Oct-22	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Sep-22	Clean Energy Future - Energy Efficiency Extension Program
Public Service Electric & Gas Company	E/G	ER22070413 & GR22070414	written	Jul-22	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER22060408	written	Jul-22	SPRC 2022
Public Service Electric & Gas Company	G	GR22060409	written	Jun-22	Gas System Modernization Program II (GSMPII) - Seventh Roll-In
Public Service Electric & Gas Company	G	GR22060367	written	Jun-22	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR22060362	written	Jun-22	Conservation Incentive Program (GCIP)
Public Service Electric & Gas Company	E/G	GR22030152	written	Mar-22	Remediation Adjustment Charge-RAC 29
Public Service Electric & Gas Company	E	ER22020035	written	Feb-22	Elecric Conservation Incentive Program (ECIP)
Public Service Electric & Gas Company	G	GR21121256	written	Dec-21	Gas System Modernization Program II (GSMPII) - Sixth Roll-In
Public Service Electric & Gas Company	E	ER21121242	written	Dec-21	Solar Successor Incentive Program (SuSI)
Public Service Electric & Gas Company	E/G	EO21111211 & GO21111212	written	Nov-21	Infrastructure Advancement Program (IAP)
Public Service Electric & Gas Company	E/G	ER21111209 & GR21111210	written	Nov-21	Energy Strong II Program (Energy Strong II) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER21101201 & GR21101202	written	Oct-21	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER21070965 & GR21070966	written	Jul-21	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	ER21060952	written	Jun-21	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR21060949	written	Jun-21	Gas System Modernization Program II (GSMPII) - Fifth Roll-In
Public Service Electric & Gas Company	E	ER21060948	written	Jun-21	SPRC 2021
PSEG New Haven LLC	PSEG New Haven LLC	21-06-40	written	Jun-21	PSEG 2022 AFRR
Public Service Electric & Gas Company	G	GR21060882	written	Jun-21	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER21050859	written	May-21	Community Solar Cost Recovery
Public Service Electric & Gas Company	G	GR20120771	written	Dec-20	Gas System Modernization Program II (GSMPII) - Forth Roll-In
Public Service Electric & Gas Company	E/G	GR20120763	written	Dec-20	Remediation Adjustment Charge-RAC 28
Public Service Electric & Gas Company	E	ER20120736	written	Nov-20	Energy Strong II Program (Energy Strong II) - First Roll-In
Public Service Electric & Gas Company	E/G	ER20100685 & GR20100686	written	Oct-20	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E	ER20100658	written	Oct-20	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER20060467 & GR20060468	written	Jun-20	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, EE17, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR20060464	written	Jun-20	Gas System Modernization Program II (GSMPII) - Third Roll-In
Public Service Electric & Gas Company	E	ER20060454	written	Jun-20	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR20060470	written	Jun-20	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR20060384	written	Jun-20	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER20040324	written	Apr-20	Transitional Renewable Energy Certificate Program (TREC)
Public Service Electric & Gas Company	E/G	GR20010073	written	Jan-20	Remediation Adjustment Charge-RAC 27
Public Service Electric & Gas Company	G	GR19120002	written	Dec-19	Gas System Modernization Program II (GSMPII) - Second Roll-In
Public Service Electric & Gas Company	E/G	ER19091302 & GR19091303	written	Aug-19	Tax Adjustment Clauses (TACs)
Public Service Electric & Gas Company	E/G	ER19070850	written	Jul-19	Societal Benefits Charge (SBC) / Cost Recovery

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	E/G	ER19060764 & GR19060765	written	Jun-19	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	G	GR19060766	written	Jun-19	Gas System Modernization Program II (GSMPII) - First Roll-In
Public Service Electric & Gas Company	G	GR19060761	written	Jun-19	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E	ER19060741	written	Jun-19	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	oral	Jun-19	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR19060698	written	May-19	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	ER19040523	written	May-19	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	oral	May-19	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E	ER19040530	written	Apr-19	Madison 4kV Substation Project (Madison & Marshall)
Public Service Electric & Gas Company	E/G	EO18101113 & GO18101112	written	Dec-18	Clean Energy Future - Energy Efficiency Program Approval
Public Service Electric & Gas Company	E/G	GR18121258	written	Nov-18	Remediation Adjustment Charge-RAC 26
Public Service Electric & Gas Company	E	EO18101115	written	Oct-18	Clean Energy Future - Energy Cloud Program (EC)
Public Service Electric & Gas Company	E	EO18101111	written	Oct-18	Clean Energy Future-Electric Vehicle And Energy Storage Programs (EVES)
Public Service Electric & Gas Company	G	GR18070831	written	Jul-18	Gas System Modernization Program (GSMP) - Third Roll-In
Public Service Electric & Gas Company	E/G	ER18070688 & GR18070689	written	Jun-18	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER18060681	written	Jun-18	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR18060675	written	Jun-18	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	EO18060629 & GO18060630	written	Jun-18	Energy Strong II / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR18060605	written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18040358 & GR18040359	written	Mar-18	Energy Strong / Revenue Requirements & Rate Design - Eighth Roll-in
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 & GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design - Seventh Roll-in
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 & GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 & GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E/G	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 & GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 & GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757 & GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389 & GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	RSG	**Delivery**			
2		Service Charge	20,547.031	20,547.031	0.000
3		Distribution Therms	1,542,229	1,552,588	10,359
4		Off-Peak Dist. Therms	41	41	0
5		Balancing Therms	1,146,626	1,156,985	10,359
6					
7		**Supply**			
8		BGSS Therms	1,508,573	1,518,774	10,202
9		BGSS Off-Peak Therms	41	41	0
10		Emergency Sales Srvc. Therms	0	0	0
11					
12					
13	GSG	**Delivery**			
14		Service Charge	1,683.551	1,683.551	0.000
15		Distribution Therms	296,690	296,812	122
16		Off-Peak Dist. Therms	12	12	0
17		Balancing Therms	210,641	210,763	122
18					
19		**Supply**			
20		BGSS Therms	238,140	238,239	99
21		Emergency Sales Srvc. Therms	0	0	0

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	LVG	**Delivery**			
2		Service Charge	234.446	234.446	0.000
3		Demand Therms	21,229	21,229	0
4		Distribution Therms 0 -1,000	136,714	137,460	745
5		Distribution Therms over 1,000	616,232	619,493	3,261
6		Balancing Therms	452,320	456,326	4,006
7					
8		**Supply**			
9		BGSS Therms	277,304	278,553	1,250
10		Emergency Sales Srvc. Therms	0	0	0
11					
12					
13	SLG	**Delivery**			
14		Lamp Chgs:			
15		Single	11.788	11.788	0.000
16		Double	0.741	0.741	0.000
17		Triple Prior to 1/1/93	18.078	18.078	0.000
18		Triple on & after 1/1/93	0.427	0.427	0.000
19		Distribution Therms	711.043	711.043	0.000
20					
21		**Supply**			
22		BGSS Therms	287.870	287.870	0.000
23		Emergency Sales Srvc. Therms	0.000	0.000	0

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	TSG-F	**Delivery**			
2		Service Charge	0.366	0.366	0.000
3		Demand Therms	451	451	0
4		Demand Therms - Agreements	0	0	0
5		Distribution Therms	22,583	22,583	0
6		Distribution Therms - Agreements	0	0	0
7					
8		**Supply**			
9		Emergency Sales Srvc. Therms	0	0	0
10					
11					
12	TSG-NF	**Delivery**			
13		Service Charge	1.838	1.838	0.000
14		Distribution Therms 0 - 50,000	55,730	55,730	0
15		Distribution Therms 0 - 50,000 - Agreements	0	0	0
16		Distribution Therms over 50,000	72,819	72,819	0
17		Distribution Therms over 50,000 - Agreements	0	0	0
18		Pilot & Penalty Therms	0	0	0
19					
20		**Supply**			
21		BGSS Therms	4,509	4,509	0
22		Emergency Sales Srvc. Therms	0	0	0
23		Pilot & Penalty Therms	0	0	0

Actual & Weather Normalized
Billing Determinants
Filing "5 and 7"

	Rate		Actual Determinants	Weather Normalized (WN) Determinants	Variation from WN
1	CIG	**Delivery**			
2		Service Charge	0.129	0.129	0.000
3		Distribution Therms 0 - 600,000	24,028	24,028	0
4		Distribution Therms over 600,000	2,011	2,011	0
5		Extended Sales Srvc. Therms	0	0	0
6					
7		**Supply**			
8		BGSS Therms	25,173	25,173	0
9		Extended Sales Srvc. Therms	866	866	0
10		Pilot & Penalty Therms	0	0	0
11					
12					
13	CSG	**Delivery**			
14		Service Charge - Power	0.000	0.000	0.000
15		Service Charge - Power- Non Firm	0.000	0.000	0.000
16		Service Charge - Other	0.230	0.230	0.000
17		Distribution Charge - Power	0	0	0
18		Distribution Charge - Power- Non Firm	0	0	0
19		Distribution Charge - Other	678,524	678,524	0
20					
21					
22		**Supply:**			
23		BGSS-Firm - Power	0	0	0
24		BGSS-Firm - Power- Non Firm	0	0	0
25		BGSS-Firm - Other	0	0	0
26					
27		BGSS-Interruptible - Power	0	0	0
28		BGSS-Interruptible - Power- Non Firm	0	0	0
29		BGSS-Interruptible - Other	0	0	0
30					
31		Emergency Sales Svc. - Power	0	0	0
32		Emergency Sales Svc. - Power- Non Firm	0	0	0
33		Emergency Sales Svc - Other	0	0	0
34		Pilot & Penalty Therms	0	0	0

COS Adjustments

Listing of plant and expense items listed in the BPU Report but not included in the COS modeling for reasons as indicated

line	FERC Account		Amount	Related to:
1	Expenses			
2	G905 MAC Adjustment Clause	$	(364,271)	MAC Adjustment Clause
3	G908 DSM Amortization		$46,805,034.86	SBC
4	G908 USF/LifelineAmortization		$53,360,246.70	SBC
5	G908 E-BRC Amortization		$7,819,110.66	Rate Case
6	Amortizations			
7	G407 & G407.3 - RAC Amortization		$30,048,016.75	RAC
8	Interest Charges			
9	G427-G431 Interest Charges	$	(1,138,521)	Interest Expense on Clauses
10	Manufactured Gas Production Expenses			
11	G729 BGSS Deferral	$	29,792,635	BGSS
12	804 & 805 Gas Purchase	$	1,244,109,804	BGSS
13	Current Tax Adjustments & Deductions			
14	Amort of Def Gain on Sale of Services Assets	$	35,437	Non Regulated Business
15	CECL Reserve	$	937,429	CECL
16	COVID Deferrals	$	(3,801,014)	COVID
17	Previously Deducted Amort - Reacquired Bonds	$	352,147	Incl'd in ROR calc.
18	Clause - Deferred Fuel	$	(3,385,475)	BGSS
19	Clause - RAC (Environmental Clean Up)	$	4,598,075	RAC
20	Clause - Societal Benefits Clause (AAP)	$	(4,643,306)	SBC
21	Clause - Demographic Studies	$	6,633	GPRC
22	Clause - Navigant Studies	$	(41,588)	GPRC
23	Deferred Taxes			
24	Amort of Def Gain on Sale of Services Assets	$	(35,437)	Non Regulated Business

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	39,041,892	4,021,862	8,979,916	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	14,684,863	1,512,747	3,377,624	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
11	S	Mains 376	CALCULATED	3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
14	S	Services 380	CALCULATED	5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
15	S	Meters 381	CALCULATED	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
16	S	Meter Installations 382	CALCULATED	52,631,537	47,983,374	4,209,056	439,073	0	33
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	0	0	0	1,521,717	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	40,711,523	8,085,630	15,684,561	13	733,346
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
23	S	General Plant E389-E399	CALCULATED	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
24	S	Common Plant C389-C399	CALCULATED	102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	14,306,794	1,416,896	787,996	597	279,572
26	S	Total Plant in Service	CALCULATED	10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	664,819,310	491,739,971	83,548,769	85,827,558	173,641	3,529,370
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	70,085	12,327	13,358	14	497
34	S	Other Rate Base Additions		1,724,917,916	1,254,838,884	222,720,026	238,447,172	258,658	8,653,176
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,945,102	-18,512,920	-2,999,915	-3,305,922	-1,385	-124,961
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-186,444,685	-32,792,082	-35,536,983	-36,739	-1,321,520
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,714,531,256	-1,248,090,931	-219,400,834	-237,956,902	-245,446	-8,837,143
39	S								
40	S	Other Rate Base Deductions		0	0	0	0	0	0
41	S	TOTAL RATE BASE		8,668,832,235	6,308,558,546	1,130,795,983	1,185,714,407	1,705,984	42,057,315
42	S								
43	S								
44	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	S								
46	S	**SUMMARY OF RESULTS**							
47	S	**DEVELOPMENT OF RETURN**							
48	S								
49	S	**RATE BASE**	CALCULATED	8,668,832,235	6,308,558,546	1,130,795,983	1,185,714,407	1,705,984	42,057,315
50	S								
51	S	**OPERATING REVENUES**							
52	S	Rate Revenues from Customers	CALCULATED	1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
53	S	Other Operating Revenues	CALCULATED	67,687,036	59,563,138	3,602,748	4,404,335	6,387	110,427
54	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
55	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
56	S	TOTAL OPERATING REVENUES		1,452,575,331	1,064,235,243	182,762,607	196,864,112	476,415	8,236,954
57	S								
58	S	**OPERATING EXPENSES**							
59	S	Operation and Maintenance Expense							
60	S	Gas Production and Supply Expense	CALCULATED	31,906,945	23,935,800	2,465,727	5,505,418	0	1
61	S	Storage Expense	CALCULATED	2,714,605	2,036,430	209,781	468,394	0	0
62	S	Transmission Expense	CALCULATED	2,593,507	1,619,114	321,579	623,646	0	29,169
63	S	Distribution Expense	CALCULATED	102,873,398	78,462,609	11,507,363	12,288,348	202,974	412,103
64	S	Customer Accounts Expense	CALCULATED	98,759,541	81,204,077	9,275,780	6,824,880	2,373	1,452,432
65	S	Customer Service & Information Expense	CALCULATED	4,034,218	3,357,834	490,597	180,904	79	4,804
66	S	Sales Expense	CALCULATED	88,423	70,127	12,936	5,339	2	19
67	S	Administrative and General Expense	CALCULATED	38,752,071	22,991,576	5,699,244	9,490,570	63,765	506,916
68	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	213,677,568	29,983,005	35,387,499	269,194	2,405,443
69	S	Depreciation Expense	CALCULATED	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
70	S	Amortization Expense	CALCULATED	2,351,634	1,860,221	253,627	211,519	203	26,064
71	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,202,614	-2,516,698	-2,610,848	-7,347	-143,216
72	S	Proforma Expense Adjustments	CALCULATED	105,999,447	80,228,329	12,217,604	12,928,861	24,113	600,541
73	S	State Income Taxes	CALCULATED	75,668,323	55,102,555	9,839,028	10,341,832	14,604	370,304
74	S	Federal Income Taxes	CALCULATED	139,157,389	101,321,526	18,144,479	18,989,756	27,923	673,705
75	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,872,797	5,491,509	6,239,970	-7,409	108,650
76	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
77	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
78	S	TOTAL OPERATING EXPENSES		812,815,512	598,663,623	99,309,863	109,358,389	350,513	5,133,124
79	S								
80	S	**OPERATING INCOME (RETURN)**		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830
81	S	Plus Operating Income Adjustment	CALCULATED						
82	S	TOTAL NET OPERATING INCOME		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830
83	S								
84	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
85	S	**INDEX RATE OF RETURN (PRESENT)**		1	1	1	1	1	1
86	S								
87	S								
88	S	**EQUALIZED RETURN AT PROPOSED ROR**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
90	S								
91	S	**RATE BASE**	CALCULATED	8,668,832,235	6,308,558,546	1,130,795,983	1,185,714,407	1,705,984	42,057,315
92	S								
93	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
94	S								
95	S	**RETURN (RATE BASE * 7.40% ROR)**		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830
96	S								
97	S	**PLUS:**							
98	S	**OPERATING EXPENSES**							
99	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	213,677,568	29,983,005	35,387,499	269,194	2,405,443
100	S	Depreciation Expense	CALCULATED	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
101	S	Amortization Expense	CALCULATED	2,351,634	1,860,221	253,627	211,519	203	26,064
102	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,202,614	-2,516,698	-2,610,848	-7,347	-143,216
103	S	Proforma Expense Adjustments	CALCULATED	105,999,447	80,228,329	12,217,604	12,928,861	24,113	600,541
104	S	Income Taxes	CALCULATED	214,825,712	156,424,081	27,983,507	29,331,588	42,527	1,044,009
105	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,872,797	5,491,509	6,239,970	-7,409	108,650
106	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
107	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
108	S	**TOTAL OPERATING EXPENSES**		812,815,512	598,663,623	99,309,863	109,358,389	350,513	5,133,124
109	S								
110	S	**EQUALS TOTAL COST OF SERVICE**		1,452,575,331	1,064,235,243	182,762,607	196,864,112	476,415	8,236,954
111	S								
112	S	**LESS:**							
113	S	Other Operating Revenues	CALCULATED	67,687,036	59,563,138	3,602,748	4,404,335	6,387	110,427
114	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
115	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
116	S	**EQUALS:**							
117	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
118	S								
119	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
120	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	13,946,341	1,358,451	718,943	521	277,046
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	360,453	58,445	69,052	76	2,526
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	14,306,794	1,416,896	787,996	597	279,572
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	14,306,794	1,416,896	787,996	597	279,572
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	39,041,892	4,021,862	8,979,916	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	39,041,892	4,021,862	8,979,916	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	14,684,863	1,512,747	3,377,624	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	14,684,863	1,512,747	3,377,624	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	PEAKHOUR_04	5,421,128	3,384,384	672,186	1,303,588	0	60,970
37	RBP	G366 Structures & Improvements	PEAKHOUR_04	0	0	0	0	0	0
38	RBP	G367 Mains	PEAKHOUR_04	93,786,847	58,550,679	11,628,982	22,552,388	0	1,054,798
39	RBP	G369 Meas. & Reg. Station Equipment	PEAKHOUR_04	4,336,420	2,707,207	537,689	1,042,754		48,771
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	PEAKHOUR_04	3,772,391,917	2,355,086,185	467,752,988	907,125,544	0	42,427,200
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	1,631,647	309,809	825,847	747	24,924
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	PEAKHOUR_04	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	4,484,987,779	640,513,095	312,808,899	0	3,703,317
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	3,018,317	573,103	1,527,700	1,381	46,106
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	317,951,582	110,270,842	48,821,087	0	1,532
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	1,755	333	888	1	27
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	47,983,018	4,208,988	438,893	0	27
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	356	68	180	0	5
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	47,983,374	4,209,056	439,073	0	33
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	32,605,191	3,994,393	1,885,454	0	2,986
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	6,483	1,231	3,282	3	99
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	32,611,675	3,995,624	1,888,736	3	3,085
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	102,955,181	8,127,539	1,598,014	0	810
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,092	207	553	0	17
101	RBP	Total Account G384		112,683,414	102,956,273	8,127,747	1,598,567	0	827
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	896,108	1,613,951	69,103,946	0	298,200
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	60,666,042	9,385,601	0	1,860,561
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	522,870	99,280	264,647	239	7,987
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	522,870	99,280	264,647	239	7,987
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	0	1,011,930	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	0	0	0	509,787	0
115	RBP	Total Accounts G387		1,521,717	0	0	0	1,521,717	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	40,711,523	8,085,630	15,684,561	13	733,346
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
152	RBP	Not Used	not_used	0	0	0	0	0	0
153	RBP	Customer Service Related	CUSTSVSX	75,768,117	64,822,307	6,314,050	3,341,634	2,421	1,287,704
154	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	18,423,767	2,987,313	3,529,456	3,898	129,090
155	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
156	RBP	Unassigned	TOTPLT	1,393,316	1,014,228	178,384	193,315	200	7,189
157	RBP	Total Accounts C389-C399		102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
158	RBP								
159	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	231,815,040	33,404,939	35,331,585	37,734	2,457,855
160	RBP								
161	RBP								
162	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	8,402,729	818,472	433,166	314	166,921
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	8,402,729	818,472	433,166	314	166,921
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	8,402,729	818,472	433,166	314	166,921
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	42,067,900	4,333,584	9,675,919	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	7,109,257	732,353	1,635,180	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	31,368,412	6,230,204	12,082,398	0	565,106
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	314,587	55,779	59,801	63	2,175
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	PEAKHOUR_04	1,017,890,245	635,463,999	126,212,020	244,766,255	0	11,447,971
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	443,986	84,302	224,720	203	6,782
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	635,907,986	126,296,322	244,990,976	203	11,454,753
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	PEAKHOUR_04	93,669,010	58,477,114	11,614,371	22,524,052	0	1,053,473
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	58,477,114	11,614,371	22,524,052	0	1,053,473
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	941,879,849	127,667,704	56,085,079	0	1,311,381
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	1,372,810	260,663	694,838	628	20,970
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	943,252,660	127,928,367	56,779,917	628	1,332,351
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	41,220,681	13,639,927	6,145,259	0	202
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	1,138	216	576	1	17
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	41,221,819	13,640,143	6,145,836	1	219
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	31,062,601	2,354,621	235,711	0	11
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	163	31	83	0	2
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	31,062,764	2,354,652	235,794	0	14
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	21,059,419	2,653,835	1,312,627	0	5,082
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	2,820	535	1,427	1	43
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	21,062,240	2,654,371	1,314,054	1	5,125
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	53,459,006	4,125,696	820,870	0	1,173
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	588	112	298	0	9
75	RBD	Total Account G384		58,407,752	53,459,594	4,125,808	821,168	0	1,182
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	23,869	289,692	11,817,896	0	105,161
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	10,344,813	1,235,941	0	655,864
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	172,909	32,831	87,517	79	2,641
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	172,909	32,831	87,517	79	2,641
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	369,687	10,700,167	13,228,870	158	766,307
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,785,128,451	299,369,981	346,100,467	1,055	14,615,600

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	69,768,158	11,312,525	13,365,542	14,760	488,845
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	69,768,158	11,312,525	13,365,542	14,760	488,845
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
107	RBD	Not Used	not_used	0	0	0	0	0	0
108	RBD	Customer Service Related	CUSTSVSX	38,276,434	32,746,845	3,189,723	1,688,122	1,223	650,521
109	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	9,651,165	1,564,884	1,848,882	2,042	67,623
110	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
111	RBD	Unassigned	TOTPLT	1,273,650	927,121	163,063	176,712	183	6,571
112	RBD	Total Accounts C389-C399 Reserve		52,684,679	43,325,131	4,917,670	3,713,716	3,447	724,715
113	RBD								
114	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
115	RBD								
116	RBD								
117	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	6,014,958,143	1,079,707,691	1,138,226,126	1,557,240	40,157,897
118	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	43,151,615	7,636,654	8,284,886	8,560	300,334
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	605,321,561	448,502,630	75,897,608	77,527,853	165,050	3,228,419
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	85,726	14,507	14,818	32	617
11	RBO	Total Working Capital		664,819,310	491,739,971	83,548,769	85,827,558	173,641	3,529,370
12	RBO	CEF-EC Adjustment	not_used						
13	RBO	CEF-EV Adjustment	not_used						
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,583,894,314	1,152,326,335	204,318,636	219,048,457	232,118	7,968,768
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Plant Held for Future Use	TOTPLT	96,280	70,085	12,327	13,358	14	497
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	141,023,603	102,512,549	18,401,390	19,398,715	26,540	684,408
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,389,833,506	1,746,648,940	306,281,121	324,288,088	432,313	12,183,043
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	(24,945,102)	(18,512,920)	(2,999,915)	(3,305,922)	(1,385)	(124,961)
23	RBO	IAP Adjustment	not_used						
24	RBO	GSMP II EXT Adjustment	TOTPLT	(256,132,009)	(186,444,685)	(32,792,082)	(35,536,983)	(36,739)	(1,321,520)
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT						
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	25,752,272	4,529,336	4,908,470	5,074	182,532
28	RBO	Liberalized Depreciation - Production	BALANCE_04	(1,955,963)	(1,467,315)	(151,154)	(337,493)		
29	RBO	Cost of Removal	TOTPLT	9,569,770	6,966,067	1,225,199	1,327,756	1,373	49,375
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	(160,793)	(116,883)	(20,981)	(22,118)	(30)	(780)
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	3,054,784	545,457	573,332	810	20,529
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,761,556,867)	(1,282,279,855)	(225,528,691)	(244,406,848)	(252,673)	(9,088,800)
35	RBO	Total Deferred Income Taxes and Credits		(1,714,531,256)	(1,248,090,931)	(219,400,834)	(237,956,902)	(245,446)	(8,837,143)
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,995,608,367)	(1,453,048,536)	(255,192,830)	(276,799,807)	(283,570)	(10,283,625)
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,668,832,235	6,308,558,546	1,130,795,983	1,185,714,407	1,705,984	42,057,315

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	0	697,710	749,505	0	0
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	40,880,111	0	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	14,267,488	2,450,176	2,639,225	6,387	110,427
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	4,415,538	454,862	1,015,606	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	59,563,138	3,602,748	4,404,335	6,387	110,427
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,452,575,331	1,064,235,243	182,762,607	196,864,112	476,415	8,236,954

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	211,536	21,791	48,655	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	22,349,708	2,302,333	5,140,593	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	1,374,514	141,594	316,148	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	23,935,758	2,465,719	5,505,396	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72	42	8	21	0	1
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72	42	8	21	0	1
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	23,935,800	2,465,727	5,505,418	0	1
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	6,681	688	1,537	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699	2,029,749	209,093	466,857		
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	2,036,430	209,781	468,394	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507	1,619,114	321,579	623,646		29,169
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	1,619,114	321,579	623,646	0	29,169
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	15,387,352	2,493,434	2,747,777	1,151	103,864
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	1,558,877	309,615	600,444	0	28,083
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	4,741	942	1,826	0	85
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	321,224	63,800	123,728	0	5,787
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	8,464,742	2,136,903	890,323	0	93
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	17,355,157	0	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	11,236,945	1,355,188	1,413,289	593	44,173
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
49	E	Total Distribution Operation		71,400,849	57,104,391	6,886,851	7,182,113	3,014	224,480
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	5,832,185	1,034,103	1,108,654	1,175	40,332
55	E	G887 Mains	PLT_376	8,706,285	5,435,034	1,079,441	2,093,906	2	97,903
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	629,226	124,973	242,363	0	11,336
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	1,970,003	391,270	758,800	0	35,490
59	E	G892 Services	SERVICES	3,610,466	2,974,434	424,881	208,327	339	2,485
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	4,510,880	1,564,448	692,640	0	22
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	6,456	1,397	1,543	60	57
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	0	198,384	0
67	E	Total Distribution Maintenance		31,472,549	21,358,219	4,620,512	5,106,235	199,960	187,623
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	78,462,609	11,507,363	12,288,348	202,974	412,103
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	106,053,954	14,504,449	18,885,805	202,975	441,273
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	11,695,648	984,362	227,828	0	0
76	E	- Meter O&M Related	METERPLT	38,249	23,265	11,125	3,740	0	119
77	E	- Remaining	MRCOST_07	0	0	0	0	0	0
78	E	G903 Customer Records and Collection							
79	E	- SONP/RNP	CUSTAVG_06	526,534	477,008	40,157	9,334	8	27
80	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
81	E	- Meter Reading Related	MRCOST_07	63,202	57,267	4,820	1,116	0	0
82	E	- Billing Related	BILLING_06	16,558,655	13,225,534	1,341,715	1,310,000	1,164	680,242
83	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	23,623,844	2,005,203	393,770	159	50,309
84	E	- Utility Work Related	UTILWORK_04	2,712,621	2,151,329	396,835	163,794	70	592
85	E	- Remaining	BILLING_06	13,832,442	11,048,085	1,120,815	1,094,322	972	568,247
86	E	Not used	not_used	0	0	0	0	0	0
87	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
88	E								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G904 Uncollectible Accounts	EXP_904	26,046,715	18,902,097	3,370,748	3,620,976	0	152,894
90	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
91	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	81,204,077	9,275,780	6,824,880	2,373	1,452,432
92	E								
93	E	CUSTOMER SERVICE & INFO EXPENSES							
94	E	G907 & 908 - Customer Service & Information							
95	E	- Billing	BILLING_06	37,379	29,855	3,029	2,957	3	1,536
96	E	- Acct Maint related	ACCTMAINT_06	746,413	676,291	57,404	11,273	5	1,440
97	E	- Utility work related	UTILWORK_04	1,684,915	1,336,275	246,490	101,739	44	368
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
99	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
100	E	G910 - Misc Cust Service & Info							
101	E	- Utility work related	UTILWORK_04	911,953	723,253	133,412	55,066	24	199
102	E	- Remaining	ACCTMAINT_06	653,558	592,160	50,263	9,870	4	1,261
103	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	3,357,834	490,597	180,904	79	4,804
104	E								
105	E	SALES EXPENSES							
106	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	70,127	12,936	5,339	2	19
107	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
108	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
109	E								
110	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	70,127	12,936	5,339	2	19
111	E								
112	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	190,685,992	24,283,761	25,896,928	205,429	1,898,527
113	E								
114	E	ADMINISTRATIVE & GENERAL EXPENSE							
115	E	G920 A&G Salaries	LABOR	6,954,680	5,942,289	497,411	464,900	3,438	46,642
116	E	G921 Office Supplies & Exp	LABOR	652,569	557,575	46,673	43,622	323	4,376
117	E	G923 Outside Services Employed							
118	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
119	E	- Remaining	TOMXFUEL904	61,043,177	46,604,280	6,587,063	7,163,913	73,435	614,485
120	E	G924 Property Insurance	TOTPLT	296,480	215,815	37,958	41,135	43	1,530
121	E	G925 Injuries & Damages	LABOR	15,351,785	13,117,029	1,097,987	1,026,222	7,590	102,958
122	E	G926 Employee Pension & Benefits							
123	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
124	E	- Remaining	LABOR	-60,778,346	-51,930,855	-4,346,975	-4,062,854	-30,048	-407,614
125	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	3,007,028	570,960	1,521,986	1,376	45,934
126	E	G929 Duplicate Charges - credit	INTRAREV	764,611	0	40,158	724,453	0	0
127	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	1,149,789	218,316	581,957	526	17,564
128	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	2,125,615	403,601	1,075,865	973	32,470
129	E	G931 Rents	AGEXP	3,713,155	2,203,012	546,091	909,370	6,110	48,572
130	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
131	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
132	E	Not Used	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	E	TOTAL A&G EXPENSE		38,752,071	22,991,576	5,699,244	9,490,570	63,765	506,916
134	E								
135	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	213,677,568	29,983,005	35,387,499	269,194	2,405,443
136	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	1,253	129	288	0	0
5	DE	Storage Plant	BALANCE_04	114,612	85,979	8,857	19,776	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	732,068	145,399	281,976	0	13,188
7	DE	Distribution Plant	DISTPLT	182,874,076	133,045,881	23,590,325	25,291,008	26,800	920,062
8	DE	General and Common Plant	COMGENPLT	19,528,227	14,938,061	2,152,600	2,276,752	2,432	158,383
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	1,021,819	99,531	52,675	38	20,299
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	DISTPLT	1,127,553	820,326	145,452	155,938	165	5,673
16	DE	Metering	METERPLT	29,719	18,076	8,644	2,906	0	92
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	1,860,221	253,627	211,519	203	26,064
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	1,860,221	253,627	211,519	203	26,064
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	150,663,462	26,150,937	28,081,319	29,435	1,117,697

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-1,738	-145	-136	-1	-14
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-9,865,086	-1,735,081	-1,880,319	-1,944	-69,924
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-51,677	-4,326	-4,043	-30	-406
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-9,284,113	-777,145	-726,350	-5,372	-72,873
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-19,202,614	-2,516,698	-2,610,848	-7,347	-143,216
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-682,298	-582,976	-48,799	-45,610	-337	-4,576
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	4,884,054	3,543,154	631,839	678,743	1,658	28,660
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	6,746,929	5,764,780	482,552	451,012	3,336	45,249
26	EO	Payroll Taxes (Rate Year)	LABOR	463,867	396,342	33,177	31,008	229	3,111
27	EO	Interest Syncronization	TOTPLTNET	-1,266,764	-920,833	-165,293	-174,252	-238	-6,148
28	EO	- add'l tax effects on rev req	TOTPLTNET	-495,322	-360,059	-64,632	-68,135	-93	-2,404
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	15,610,563	13,338,137	1,116,495	1,043,520	7,718	104,693
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	0	0	0	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-151,008	-26,559	-28,783	-30	-1,070
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-59,046	-10,385	-11,254	-12	-419
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	-328,894	-239,410	-42,108	-45,632	-47	-1,697
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	262,863	191,345	33,654	36,471	38	1,356
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-4,318,591	-759,558	-823,138	-851	-30,610
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	14,761,516	10,745,265	1,889,888	2,048,084	2,117	76,162
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	150,424	109,497	19,259	20,871	22	776
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	71,386,007	52,149,864	9,076,020	9,767,303	10,245	382,576
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		105,999,447	80,228,329	12,217,604	12,928,861	24,113	600,541
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		81,518,725	61,025,715	9,700,906	10,318,013	16,766	457,325
61	EO	COLI Interest Expense Recovery	LABOR	727,815	621,867	52,055	48,652	360	4,881

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,452,575,331	1,064,235,243	182,762,607	196,864,112	476,415	8,236,954
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	213,677,568	29,983,005	35,387,499	269,194	2,405,443
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	150,663,462	26,150,937	28,081,319	29,435	1,117,697
7	TI	OTHER OPERATING EXPENSES	CALCULATED	81,518,725	61,025,715	9,700,906	10,318,013	16,766	457,325
8	TI	NET OPERATING INCOME BEFORE TAXES		883,291,047	638,868,499	116,927,759	123,077,281	161,020	4,256,488
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	73,287,889	13,155,453	13,868,457	18,974	489,295
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		782,470,979	565,580,610	103,772,306	109,208,824	142,046	3,767,194
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	41,276	7,409	7,811	11	276
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	37,986	6,819	7,188	10	254
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	303,465	53,374	57,842	60	2,151
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-796,557	-142,985	-150,735	-206	-5,318
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP II	TOTPLT	8,262	6,014	1,058	1,146	1	43
23	TI	Deferred Return on CIP II	TOTPLT	18,055	13,143	2,312	2,505	3	93
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-303,860	-54,544	-57,500	-79	-2,029
31	TI	Material Supplies & Reserves	TOTPLT	78,535	57,168	10,055	10,896	11	405
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-331,253	-59,461	-62,684	-86	-2,212
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-236,415	-42,437	-44,737	-61	-1,578
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-10	-2	-2	0	0
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	5,668	997	1,080	1	40
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-300,969	-25,193	-23,547	-174	-2,362
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-12,449	-1,042	-974	-7	-98
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-15,904,798	-2,768,028	-2,978,857	-3,124	-116,679
60	TI	Customer Advances	TOTPLTNET	294,687	214,213	38,452	40,536	55	1,430
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-3,741	-313	-293	-2	-29
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-4,954,207	-414,702	-387,596	-2,867	-38,886
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	676	119	129	0	5
65	TI	Entertainment (100%)	LABOR	36,298	31,014	2,596	2,426	18	243
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	760,505	133,758	144,955	150	5,390
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-45,223,057	-7,870,497	-8,469,960	-8,884	-331,760
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	119,096	9,969	9,318	69	935
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-55,117	-9,694	-10,505	-11	-391
75	TI	R&D Expenditure	TOTPLT	-16,866	-12,277	-2,159	-2,340	-2	-87
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-378,047	-66,491	-72,057	-74	-2,680
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	433,103	76,175	82,551	85	3,070
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	104,062	8,711	8,141	60	817
81	TI	State NOL CF (c)	DEPREXP	7,732,062	5,648,530	983,055	1,057,930	1,110	41,438
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-59,025	-10,381	-11,250	-12	-418
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	103,473	18,199	19,722	20	733
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	EXP_904	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-392,360	-32,843	-30,697	-227	-3,080
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-613,991	-110,214	-116,187	-159	-4,099
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Book Depreciation	DEPREXP	0	0	0	0	0	0
95	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
96	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
97	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
98	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
99	TI	AFUDC / IDC	TOTPLT	-345,079	-251,191	-44,180	-47,878	-49	-1,780
100	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
101	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
102	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
103	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
104	TI	Deferred Comp - officers	LABOR	-15,155	-12,949	-1,084	-1,013	-7	-102
105	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
106	TI	Accrued vacation pay adjustment	LABOR	-257,985	-220,431	-18,452	-17,246	-128	-1,730
107	TI	3rd Party Claims	TOTPLT	-975	-709	-125	-135	0	-5
108	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
109	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
110	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
111	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-6,647,768	-556,465	-520,094	-3,847	-52,179
112	TI	Unallowable OPEB Amortization	LABOR	47,224,310	40,349,877	3,377,566	3,156,806	23,347	316,713
113	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
114	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
115	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	1,287,482	107,771	100,727	745	10,106
116	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
117	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
118	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
119	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
120	TI	Restricted Stock - Permanent	LABOR	-67,594	-57,755	-4,834	-4,518	-33	-453
121	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
122	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
123	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
124	TI	Penalties	not_used	0	0	0	0	0	0
125	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
126	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-742,407	-133,265	-140,488	-192	-4,957
127	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
128	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
129	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
130	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
131	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-27,994,596	-7,530,999	-8,439,583	5,524	-188,771
132	TI								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI								
134	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
135	TI								
136	TI	**TAX ADJUSTMENTS - STATE**							
137	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
138	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	47,080,081	8,280,493	8,973,622	9,277	333,704
139	TI	State Tax Depreciation	DEPREXP	37,759,415	27,584,515	4,800,734	5,166,385	5,419	202,362
140	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
141	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
142	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	74,664,595	13,081,226	14,140,007	14,696	536,066
143	TI								
144	TI	**TAXABLE NET INCOME - STATE**		840,759,145	612,250,609	109,322,534	114,909,247	162,266	4,114,488
145	TI	State Tax Liability		75,668,323	55,102,555	9,839,028	10,341,832	14,604	370,304
146	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
147	TI	**TOTAL STATE INCOME TAX LIABILITY**		75,668,323	55,102,555	9,839,028	10,341,832	14,604	370,304
148	TI								
149	TI	**TAXABLE NET INCOME - FEDERAL**		662,654,232	482,483,459	86,402,280	90,427,408	132,966	3,208,118
150	TI	Federal Tax Liability		139,157,389	101,321,526	18,144,479	18,989,756	27,923	673,705
151	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
152	TI	Not Used	not_used	0	0	0	0	0	0
153	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		139,157,389	101,321,526	18,144,479	18,989,756	27,923	673,705
154	TI								
155	TI	**TOTAL INCOME TAX EXPENSE**		214,825,712	156,424,081	27,983,507	29,331,588	42,527	1,044,009
156	TI								
157	TI	**TAX RATES**							
158	TI	FEDERAL TAX RATE - CURRENT		21.000%					
159	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
160	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0					
161	TI	EFFECTIVE TAX RATE		28.110%					
162	TI	COMPOSITE RATE		28.110%					
163	TI	1 - EFFECTIVE TAX RATE		71.89000%					
164	TI								
165	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
166	TI								
167	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
168	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
169	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
170	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
171	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	10	2	2	0	0
172	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-23,109	-4,064	-4,405	-5	-164
173	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	796,558	142,985	150,735	206	5,318
174	TI	CECL Reserve	not_used	0	0	0	0	0	0
175	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
176	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
178	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
179	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
180	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
181	TI	COVID Deferrals	not_used	0	0	0	0	0	0
182	TI	Current SHARE -- FT	DEPREXP	5,506,769	4,022,879	700,131	753,457	790	29,512
183	TI	Customer Advances	TOTPLTNET	-294,687	-214,213	-38,452	-40,536	-55	-1,430
184	TI	Deduction for Retention Payments (c)	LABOR	4,379	3,741	313	293	2	29
185	TI	Deferred Employer ER FICA	LABOR	5,798,258	4,954,207	414,702	387,596	2,867	38,886
186	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
187	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
188	TI	Injuries & Damages - FT	TOTPLT	-264,256	-192,358	-33,832	-36,664	-38	-1,363
189	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
190	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
191	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
192	TI	Plant Related	DEPREXP	62,706,788	45,809,404	7,972,544	8,579,779	8,999	336,062
193	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
194	TI	R & D Credits CF	TOTPLT	-67,859	-49,396	-8,688	-9,415	-10	-350
195	TI	RE - Lease Liability	TOTPLT	519,350	378,047	66,491	72,057	74	2,680
196	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-433,103	-76,175	-82,551	-85	-3,070
197	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	743,435	130,756	141,701	146	5,269
198	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
199	TI	Severance Pay (nc)	LABOR	-121,791	-104,062	-8,711	-8,141	-60	-817
200	TI	State NOL CF (c)	DEPREXP	-7,732,062	-5,648,530	-983,055	-1,057,930	-1,110	-41,438
201	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-103,473	-18,199	-19,722	-20	-733
202	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
203	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
204	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
205	TI	AFUDC / IDC	TOTPLT	345,079	251,191	44,180	47,878	49	1,780
206	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-303,465	-53,374	-57,842	-60	-2,151
207	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
208	TI	Deferred Comp - officers	LABOR	15,155	12,949	1,084	1,013	7	102
209	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
210	TI	Accrued vacation pay adjustment	LABOR	257,985	220,431	18,452	17,246	128	1,730
211	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
212	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
213	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
214	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
215	TI	Pension Accrual Adjustment	LABOR	7,780,352	6,647,768	556,465	520,094	3,847	52,179
216	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-40,349,877	-3,377,566	-3,156,806	-23,347	-316,713
217	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
218	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
219	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
220	TI	PIP Adjustment	LABOR	455,695	389,360	32,592	30,462	225	3,056

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0
222	TI	Misc	TOTPLT	0	0	0	0	0	0
223	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
224	TI	Deferred Return on CIP II	TOTPLT	-18,055	-13,143	-2,312	-2,505	-3	-93
225	TI	Deferred Depreciation on CIP II	TOTPLT	-8,262	-6,014	-1,058	-1,146	-1	-43
226	TI	Investment Tax Credit	TOTPLT	-493,265	-359,060	-63,152	-68,438	-71	-2,545
227	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-41,276	-7,409	-7,811	-11	-276
228	TI	3rd Party Claims	TOTPLT	975	709	125	135	0	5
229	TI	Customer Connections Fees		0	0	0	0	0	0
230	TI	Legal Reserves (nc)	TOTPLTNET	418,012	303,860	54,544	57,500	79	2,029
231	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-57,089	-10,248	-10,803	-15	-381
232	TI	Stock Based Compensation	TOTPLTNET	325,229	236,415	42,437	44,737	61	1,578
233	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	16,872,797	5,491,509	6,239,970	-7,409	108,650
234	TI								
235	TI	**This Section is not used at this time**							
236	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	Not Used	not_used	0	0	0	0	0	0
240	TI	**OPERATING INCOME ADJUSTED**		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	583,871	60,147	134,294	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	306,054	31,528	70,395	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	301,701	59,922	116,208	0	5,435
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	2,641,804	501,613	1,337,131	1,209	40,355
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	10,651,043	1,725,942	1,901,997	797	71,894
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	854,400	169,696	329,095	0	15,392
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	6,306,606	1,592,087	663,330	0	69
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	63,057,319	0	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	4,174,315	503,427	525,010	220	16,409
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	-35	-7	-18	0	-1
21	LR	Total Operation		97,081,101	87,685,453	4,492,758	4,756,545	2,226	144,119
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	738,781	130,993	140,437	149	5,109
26	LR	G887 Mains	EXP_887	4,445,965	2,775,463	551,229	1,069,277	1	49,995
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	1,364,311	270,971	525,502	0	24,578
29	LR	G892 Services	EXP_892	2,126,460	1,751,856	250,243	122,699	200	1,464
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	3,362,194	1,166,064	516,261	0	16
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	2,208	478	528	67,862	19
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	9,994,812	2,369,978	2,374,703	68,211	81,181
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	97,680,265	6,862,735	7,131,248	70,437	225,300
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	38,650,888	3,663,362	1,987,637	1,472	806,207
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	2,503,466	365,769	134,875	59	3,582
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	2,797	516	213	0	1
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	4,126,207	1,022,821	1,703,235	11,444	90,974
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	144,155,248	12,066,799	11,278,106	83,412	1,131,499

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	-1,700,938	-175,221	-391,228	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	6,280,141	646,943	1,444,478	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	7	1	3	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improvemer	PLT_3745	2,620,552	1,906,523	338,045	362,416	384	13,184
10	CA	G376 Mains	PLT_376	226,633,216	141,479,307	28,098,909	54,506,455	45	2,548,501
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	35,627,943	7,076,207	13,723,072	0	641,842
13	CA	G380 Services	SERVICES	505,466,924	416,422,163	59,483,542	29,165,898	47,429	347,892
14	CA	G381 Meters	PLT_381	58,899,779	39,256,803	13,614,871	6,027,912	0	193
15	CA	G382 Meter Installations	PLT_382	-1,810,761	-1,650,843	-144,810	-15,106	0	-1
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,034,053	181,898	52,323	0	59
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	169,884	5,465,993	6,913,035	42	190,259
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	635,245,832	114,114,655	110,736,003	47,900	3,741,928
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	19,192,160	3,111,904	3,676,658	4,060	134,474
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	659,017,202	117,698,282	115,465,913	51,960	3,876,402

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	77,879	15,468	29,997	0	1,403
6	AF	**COMMODITY RELATED**							
7	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
8	AF	Balancing therms - delivery	BALANCE_04	1,793,060	1,345,110	138,565	309,385	0	0
9	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
10	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
11	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
12	AF								
13	AF	**BILLING DETERMINANTS**							
14	AF	Number of Customers		1,894,095	1,728,739	145,499	19,809	16	32
15	AF	Transported Gas at Meter (calendar)		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
16	AF								
17	AF								
18	AF	**CUSTOMER RELATED**							
19	AF	G380 services - access	SERVICES_03	1,215,746,207	1,001,946,668	143,090,682	69,881,536	0	827,321
20	AF	Cust Installns LDC G879 - delivery	CINST_04	100	100	0	0	0	0
21	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	598,870	50,415	11,719	9	34
22	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	598,870	50,415	11,719	9	34
23	AF	G381 meters - measurement	SMMETERS_07	95,373,410	63,566,590	22,045,940	9,760,574	0	306
24	AF								
25	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	16,641,744	1,688,285	1,648,379	1,464	855,952
26	AF	Competitive Service work - delivery	COMPSVSWK_04	100	100	0	0	0	0
27	AF								
28	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	60,880,342	5,167,551	1,014,774	411	129,650
29	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,257	136,288,569	11,955,000	1,246,610	0	78
30	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	23,488,422	2,877,517	1,358,260	0	2,151
31	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	45,273,401	3,573,995	702,709	0	356
32	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	527,983	950,933	40,715,751	0	175,698
33	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	5,728,862	886,308	0	175,698
34	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	252,625,678	34,242,308	15,042,822	0	351,731
35	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	26,782,366	8,862,287	3,992,767	0	131
36	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	65,486,599	4,964,044	496,929	0	24
37	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	3,992,277	503,093	248,837	0	963
38	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,043,509	697,932	138,864	0	198
39	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	13,538	164,305	6,702,764	0	59,644
40	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	940,755	112,396	0	59,644
41	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
42	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0
43	**AF**	**ALLOCATION FACTOR TABLE**							
44	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	AF								
46	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	0	1	0
47	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	14,755,434	1,241,888	287,431	0	0
48	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	5,374,648	991,409	409,204	176	1,480
49	AF	Direct SLG - access	DIRSLG_03	1	0	0	0	1	0
50	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
51	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
52	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
53	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
54	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
55	AF	Choice - delivery	CHOICE_04	1,894,095	1,728,739	145,499	19,809	16	32
56	AF								
57	AF								
58	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
59	AF								
60	AF								
61	AF	**Plant Related**							
62	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
63	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	14,306,794	1,416,896	787,996	597	279,572
64	AF	Production Plant Total	PRODPLT	52,043,670	39,041,892	4,021,862	8,979,916	0	0
65	AF	Storage Plant Total	STORPLT	19,575,233	14,684,863	1,512,747	3,377,624	0	0
66	AF	Transmission Plant Total	TRANPLT	103,544,395	64,642,269	12,838,857	24,898,729	0	1,164,539
67	AF	Distribution Plant Total	DISTPLT	10,498,076,770	7,637,637,323	1,354,227,179	1,451,856,664	1,538,485	52,817,119
68	AF	G391-G398 General Plant	GENPLT	200,812,197	147,554,738	23,925,192	28,267,180	31,216	1,033,872
69	AF	Common Plant	COMPLT	102,234,955	84,260,302	9,479,747	7,064,405	6,518	1,423,983
70	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	231,815,040	33,404,939	35,331,585	37,734	2,457,855
71	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	7,756,006,347	1,372,600,645	1,489,112,933	1,538,485	53,981,658
72	AF	Total Plant	TOTPLT	10,993,079,074	8,002,128,180	1,407,422,480	1,525,232,514	1,576,816	56,719,085
73	AF								
74	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	7,271,177,742	1,178,981,626	1,392,945,368	1,538,245	50,946,978
75	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	70,215,496	12,449,888	13,347,431	14,144	485,566
76	AF	Acct G376 - Mains	PLT_376	3,775,184,891	2,356,717,833	468,062,797	907,951,391	747	42,452,124
77	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
78	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	178,539,869	35,460,510	68,769,490	0	3,216,420
79	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	4,488,006,097	641,086,199	314,336,599	511,168	3,749,423
80	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	6,844,723,929	1,109,148,995	1,222,287,991	511,915	46,201,547
81	AF	Acct G381 - House Meters	PLT_381	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
82	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	47,983,374	4,209,056	439,073	0	33
83	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	366,459,581	175,245,553	58,911,296	240	1,870,140
84	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	501,504,659	126,603,602	52,748,351	4	5,504
85	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	183,551,322	16,332,427	3,926,376	4	3,945
86	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
87	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
88	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	AF								
90	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
91	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
92	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	0	1,011,930	0
93	AF								
94	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,987,170,038	327,714,788	387,006,388	19,576	16,561,188
95	AF	Total Net Plant	TOTPLTNET	8,274,607,096	6,014,958,143	1,079,707,691	1,138,226,126	1,557,240	40,157,897
96	AF								
97	AF								
98	AF	**Revenue Related**							
99	AF	Total Operating Revenue	TOTREV	1,452,575,331	1,064,235,243	182,762,607	196,864,112	476,415	8,236,954
100	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	191,712,321	0	10,068,784	181,643,537	0	0
101	AF								
102	AF								
103	AF	**Expense Related**							
104	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	1,586,050	163,385	364,803	0	0
105	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	2,036,430	209,781	468,394	0	0
106	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	1,619,114	321,579	623,646	0	29,169
107	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	42	8	21	0	1
108	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
109	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
110	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	15,387,352	2,493,434	2,747,777	1,151	103,864
111	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	1,884,842	374,356	725,998	0	33,956
112	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	8,464,742	2,136,903	890,323	0	93
113	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	17,355,157	0	0	0	0
114	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	11,236,945	1,355,188	1,413,289	593	44,173
115	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
116	AF	Acct 881 - Rents	EXP_881	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
117	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	5,832,185	1,034,103	1,108,654	1,175	40,332
118	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	5,435,034	1,079,441	2,093,906	2	97,903
119	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
120	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	2,599,229	516,243	1,001,164	0	46,825
121	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	2,974,434	424,881	208,327	339	2,485
122	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	4,510,880	1,564,448	692,640	0	22
123	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	6,456	1,397	1,543	198,445	57
124	AF								
125	AF	Distr Oper Exp	DISTEXPO	71,400,849	57,104,391	6,886,851	7,182,113	3,014	224,480
126	AF	Distr Maint Exp	DISTEXPM	31,472,549	21,358,219	4,620,512	5,106,235	199,960	187,623
127	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	3,357,834	490,597	180,904	79	4,804
128	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
129	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	65,659,814	6,395,628	3,384,808	2,452	1,304,342
130	AF	Sales Expense	SALESEXP	88,423	70,127	12,936	5,339	2	19
131	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
132	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF								
134	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	190,685,992	24,283,761	25,896,928	205,429	1,898,527
135	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	194,775,471	26,612,257	31,766,523	269,194	2,252,549
136	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	170,839,713	24,146,538	26,261,127	269,194	2,252,549
137	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	22,991,576	5,699,244	9,490,570	63,765	506,916
138	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
139	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	872,694,769	147,681,287	150,853,412	321,154	6,281,845
140	AF								
141	AF	Depreciation Expense (total)	DEPREXP	203,691,216	148,803,241	25,897,310	27,869,800	29,232	1,091,633
142	AF								
143	AF	NJ State Income Tax (CBT)	STATEINCTAX	75,668,323	55,102,555	9,839,028	10,341,832	14,604	370,304
144	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-33,702,109	-2,821,102	-2,636,713	-19,501	-264,534
145	AF								
146	AF	**Labor Expense Related**							
147	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	87,685,453	4,492,758	4,756,545	2,226	144,119
148	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	9,994,812	2,369,978	2,374,703	68,211	81,181
149	AF	Total Labor	LABOR	168,715,063	144,155,248	12,066,799	11,278,106	83,412	1,131,499
150	AF								
151	AF	**REVENUES AND BILLING DETERMINANTS**							
152	AF								
153	AF	Base Rate Sales Revenue	SALESREV	1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
154	AF								
155	AF	Residential Service Gas	REVRSG	1,004,672,106	1,004,672,106	0	0	0	0
156	AF	General Service Gas	REVGSG	179,159,859	0	179,159,859	0	0	0
157	AF	Large Volume Service Gas	REVLVG	192,459,776	0	0	192,459,776	0	0
158	AF	Street Light Gas	REVSLG	470,028	0	0	0	470,028	0
159	AF	Firm Transportation Gas Service	REVTSGF	8,126,527	0	0	0	0	8,126,527
160	AF								
161	AF								
162	AF	Total Rev Req @ desired ROR	REVREQ	1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
163	AF								
164	AF								
165	AF	**PRESENT REVENUES FROM SALES INPUT**							
166	AF								
167	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
168	AF	Sales of Gas Revenues - Rates		1,101,761	808,939	129,770	150,330	438	12,284
169	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
170	AF								
171	AF	**RATE OF RETURN**							
172	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
6	AP								
7	AP	**COMMODITY RELATED**							
8	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
9	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
10	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
11	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
12	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AF								
14	AP	**BILLING DETERMINANTS**							
15	AP	Number of Customers		1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
16	AP	Transported Gas at Meter (calendar)		1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
17	AP								
18	AP								
19	AP	**CUSTOMER RELATED**							
20	AP	G380 services - access	SERVICES_03	1.000000	0.824141	0.117698	0.057480	0.000000	0.000681
21	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
22	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
23	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
24	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
25	AP								
26	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.798708	0.081028	0.079113	0.000070	0.041081
27	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
28	AF								
29	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.906056	0.076906	0.015102	0.000006	0.001930
30	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.911689	0.079972	0.008339	0.000000	0.000001
31	AP	G383 house regulators - access	HOUSEREG_03	1.000000	0.847152	0.103783	0.048988	0.000000	0.000078
32	AP	G384 house reg install - access	HSEREGINST_03	1.000000	0.913683	0.072128	0.014182	0.000000	0.000007
33	AP	G385 lrg regulators - access	LRGREG_03	1.000000	0.012461	0.022443	0.960949	0.000000	0.004147
34	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.843613	0.130515	0.000000	0.025873
35	AP	G380 services - reserve - access	SERVICESR_03	1.000000	0.835782	0.113287	0.049767	0.000000	0.001164
36	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.675682	0.223583	0.100732	0.000000	0.000003
37	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.923028	0.069968	0.007004	0.000000	0.000000
38	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	0.841335	0.106022	0.052440	0.000000	0.000203
39	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	0.915288	0.070637	0.014054	0.000000	0.000020
40	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	0.001951	0.023674	0.965781	0.000000	0.008594
41	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.845398	0.101003	0.000000	0.053598
42	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
46	AP								
47	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
48	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.906089	0.076261	0.017650	0.000000	0.000000
49	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
50	AP	Direct SLG - access	DIRSLG_03	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
51	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Choice - delivery	CHOICE_04	1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
57	AP								
58	AP								
59	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
60	AP								
61	AP								
62	AP	**Plant Related**							
63	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.852008	0.084380	0.046927	0.000036	0.016649
65	AP	Production Plant Total	PRODPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
66	AP	Storage Plant Total	STORPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
67	AP	Transmission Plant Total	TRANPLT	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
68	AP	Distribution Plant Total	DISTPLT	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
69	AP	G391-G398 General Plant	GENPLT	1.000000	0.734790	0.119142	0.140764	0.000155	0.005148
70	AP	Common Plant	COMPLT	1.000000	0.824183	0.092725	0.069100	0.000064	0.013929
71	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.764947	0.110230	0.116588	0.000125	0.008110
72	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.726678	0.128602	0.139518	0.000144	0.005058
73	AP	Total Plant	TOTPLT	1.000000	0.727924	0.128028	0.138745	0.000143	0.005160
74	AP								
75	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.734790	0.119142	0.140764	0.000155	0.005148
76	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
77	AP	Acct G376 - Mains	PLT_376	1.000000	0.624266	0.123984	0.240505	0.000000	0.011245
78	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
80	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
81	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.742146	0.120261	0.132528	0.000056	0.005009
82	AP	Acct G381 - House Meters	PLT_381	1.000000	0.666502	0.231153	0.102342	0.000000	0.000003
83	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.911685	0.079972	0.008342	0.000000	0.000001
84	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.608245	0.290870	0.097780	0.000000	0.003104
85	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
86	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.900582	0.080134	0.019264	0.000000	0.000019
87	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	0.896717	0.080190	0.023067	0.000000	0.000026
88	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AP								
91	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.013336	0.429068	0.542658	0.000003	0.014935
92	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
93	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
94	AP								
95	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.730988	0.120551	0.142362	0.000007	0.006092
96	AP	Total Net Plant	TOTPLTNET	1.000000	0.726918	0.130484	0.137557	0.000188	0.004853
97	AP								
98	AP								
99	AP	**Revenue Related**							
100	AP	Total Operating Revenue	TOTREV	1.000000	0.732654	0.125820	0.135528	0.000328	0.005671
101	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.000000	0.052520	0.947480	0.000000	0.000000
102	AP								
103	AP								
104	AP	**Expense Related**							
105	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
106	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
107	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
108	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
109	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
110	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
111	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.742146	0.120261	0.132528	0.000056	0.005009
112	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
113	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
114	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
115	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.799772	0.096453	0.100589	0.000042	0.003144
116	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
117	AP	Acct 881 - Rents	EXP_881	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
118	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.727527	0.128998	0.138297	0.000147	0.005031
119	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.624266	0.123984	0.240505	0.000000	0.011245
120	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
121	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
122	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
123	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
124	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.031052	0.006718	0.007424	0.954533	0.000273
125	AP								
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.799772	0.096453	0.100589	0.000042	0.003144
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.678630	0.146811	0.162244	0.006353	0.005961
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.832338	0.121609	0.044842	0.000019	0.001191
129	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
130	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.855535	0.083334	0.044103	0.000032	0.016995
131	AP	Sales Expense	SALESEXP	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
132	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.784811	0.099945	0.106585	0.000845	0.007814

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.761806	0.104086	0.124245	0.001053	0.008810
134	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.763464	0.107908	0.117358	0.001203	0.010066
135	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.593299	0.147069	0.244905	0.001645	0.013081
136	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.740933	0.125384	0.128077	0.000273	0.005333
138	AP								
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.730533	0.127140	0.136824	0.000144	0.005359
140	AP								
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.728212	0.130028	0.136673	0.000193	0.004894
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.854430	0.071522	0.066847	0.000494	0.006707
143	AP								
144	AP	**Labor Expense Related**							
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.903219	0.046278	0.048996	0.000023	0.001485
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.671294	0.159178	0.159495	0.004581	0.005452
147	AP	Total Labor	LABOR	1.000000	0.854430	0.071522	0.066847	0.000494	0.006707
148	AP								
149	AP	**REVENUES AND BILLING DETERMINANTS**							
150	AP								
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.725454	0.129368	0.138971	0.000339	0.005868
152	AP								
153	AP	Residential Service Gas	REVRSG	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
154	AP	General Service Gas	REVGSG	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
155	AP	Large Volume Service Gas	REVLVG	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
156	AP	Street Light Gas	REVSLG	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
157	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
158	AP								
159	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.725454	0.129368	0.138971	0.000339	0.005868
160	AP								
161	AP	**PRESENT REVENUES FROM SALES INPUT**							
162	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
163	AP	Sales of Gas Revenues - Rates		1.000000	0.734224	0.117784	0.136445	0.000397	0.011149
164	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,004,672,106	1,004,672,106	0	0	0	0
6	ADA	General Service Gas	REVGSG	179,159,859	0	179,159,859	0	0	0
7	ADA	Large Volume Service Gas	REVLVG	192,459,776	0	0	192,459,776	0	0
8	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
9	ADA	Firm Transportation Gas Service	REVTSGF	8,126,527	0	0	0	0	8,126,527
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,384,418,267	1,004,672,106	179,159,859	192,459,776	0	8,126,527
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.725700	0.129412	0.139019	0.0	0.005870
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	179,159,859	0	179,159,859	0	0	0
20	ADA	Large Volume Service Gas	REVLVG	192,459,776	0	0	192,459,776	0	0
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	371,619,635	0	179,159,859	192,459,776	0	0
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.0	0.482105	0.517895	0.0	0.0
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	----------							
5	RRW	RATE BASE		8,668,832,235	6,308,558,546	1,130,795,983	1,185,714,407	1,705,984	42,057,315
6	RRW	NET OPER INC (PRESENT RATES)		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
10	RRW	REVENUE PRES RATES $/THERM		$0.5330	$0.6619	$0.6216	$0.2505	$0.6765	$0.3505
11	RRW	REVENUE REQUIRED - $/MO/CUST		$60.93	$48.43	$102.61	$809.65	$2,448.06	$21,162.83
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	----------							
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		639,759,819	465,571,621	83,452,744	87,505,723	125,902	3,103,830
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,384,888,295	1,004,672,106	179,159,859	192,459,776	470,028	8,126,527
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
22	RRW	SALES REV REQUIRED $/THERM		$0.5330	$0.6619	$0.6216	$0.2505	$0.6765	$0.3505
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	0	52,043,670	0	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	0	19,575,233	0	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	0	103,544,395	0	0	0
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
11	S	Mains 376	CALCULATED	3,775,184,891	0	3,775,184,891	0	0	0
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	0	285,986,290	0	0	0
14	S	Services 380	CALCULATED	5,447,179,699	5,447,179,699	0	0	0	0
15	S	Meters 381	CALCULATED	477,048,047	0	0	0	0	477,048,047
16	S	Meter Installations 382	CALCULATED	52,631,537	0	0	0	0	52,631,537
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	151,182,537	0	0	0	0
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	72,807,227	0	0	0	72,807,227
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	509,787	0	1,011,930	0	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	0	65,215,073	0	0	0
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
23	S	General Plant E389-E399	CALCULATED	200,812,197	116,163,890	84,514,137	20,726	0	113,444
24	S	Common Plant C389-C399	CALCULATED	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
26	S	Total Plant in Service	CALCULATED	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	664,819,310	328,100,861	243,498,996	139,563	36,758,575	56,321,315
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	51,288	38,905	9	614	5,464
34	S	Other Rate Base Additions		1,724,917,916	941,492,892	682,274,946	171,705	570,540	100,407,833
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,945,102	-14,734,362	-10,210,740	0	0	0
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,714,531,256	-912,227,766	-694,060,619	-162,620	-10,914,323	-97,165,928
39	S								
40	S	Other Rate Base Deductions							
41	S	TOTAL RATE BASE		8,668,832,235	4,773,532,754	3,282,465,244	1,157,811	58,258,668	553,417,758
42	S								
43	S								
44	S	**SUMMARY OF RESULTS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	S	**DEVELOPMENT OF RETURN**							
46	S								
47	S	**RATE BASE**	CALCULATED	8,668,832,235	4,773,532,754	3,282,465,244	1,157,811	58,258,668	553,417,758
48	S								
49	S	**OPERATING REVENUES**							
50	S	Rate Revenues from Customers	CALCULATED	1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
51	S	Other Operating Revenues	CALCULATED	67,687,036	9,775,057	55,172,879	5,295	1,110,298	1,623,507
52	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
53	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
54	S	TOTAL OPERATING REVENUES		1,452,575,331	692,319,743	569,448,755	394,929	79,903,557	110,508,346
55	S								
56	S	**OPERATING EXPENSES**							
57	S	Operation and Maintenance Expense							
58	S	Gas Production and Supply Expense	CALCULATED	31,906,945	0	31,906,945	0	0	0
59	S	Storage Expense	CALCULATED	2,714,605	0	2,714,605	0	0	0
60	S	Transmission Expense	CALCULATED	2,593,507	0	2,593,507	0	0	0
61	S	Distribution Expense	CALCULATED	102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
62	S	Customer Accounts Expense	CALCULATED	98,759,541	12,840,193	12,388,188	0	58,473,292	15,057,869
63	S	Customer Service & Information Expense	CALCULATED	4,034,218	0	2,596,868	0	1,437,350	0
64	S	Sales Expense	CALCULATED	88,423	0	88,423	0	0	0
65	S	Administrative and General Expense	CALCULATED	38,752,071	6,446,494	14,707,756	58,280	11,600,390	5,939,152
66	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	45,694,652	124,897,432	257,504	71,511,031	39,362,089
67	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
68	S	Amortization Expense	CALCULATED	2,351,634	614,823	529,938	110	909,279	297,484
69	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,227,401	-11,490,389	-6,368	-2,580,842	-2,175,722
70	S	Proforma Expense Adjustments	CALCULATED	105,999,447	46,052,558	45,364,074	19,367	6,848,045	7,715,403
71	S	State Income Taxes	CALCULATED	75,668,323	41,426,245	28,824,461	9,948	596,086	4,811,582
72	S	Federal Income Taxes	CALCULATED	139,157,389	76,515,015	52,588,272	19,081	1,034,353	9,000,668
73	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,773,035	6,152,359	-9,462	-6,431,525	-778,891
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		812,815,512	340,033,026	327,202,820	309,483	75,604,068	69,666,115
77	S								
78	S	**OPERATING INCOME (RETURN)**		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231
79	S	Plus Operating Income Adjustment	CALCULATED						
80	S	TOTAL NET OPERATING INCOME		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231
81	S								
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00
84	S								
85	S								
86	S	**EQUALIZED RETURN AT PROPOSED ROR**							
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
88	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**RATE BASE**	CALCULATED	8,668,832,235	4,773,532,754	3,282,465,244	1,157,811	58,258,668	553,417,758
90	S								
91	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
92	S								
93	S	**RETURN (RATE BASE * 7.40% ROR)**		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231
94	S								
95	S	**PLUS:**							
96	S	**OPERATING EXPENSES**							
97	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	45,694,652	124,897,432	257,504	71,511,031	39,362,089
98	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
99	S	Amortization Expense	CALCULATED	2,351,634	614,823	529,938	110	909,279	297,484
100	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,227,401	-11,490,389	-6,368	-2,580,842	-2,175,722
101	S	Proforma Expense Adjustments	CALCULATED	105,999,447	46,052,558	45,364,074	19,367	6,848,045	7,715,403
102	S	Income Taxes	CALCULATED	214,825,712	117,941,260	81,412,733	29,029	1,630,439	13,812,251
103	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,773,035	6,152,359	-9,462	-6,431,525	-778,891
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED						
106	S	**TOTAL OPERATING EXPENSES**		812,815,512	340,033,026	327,202,820	309,483	75,604,068	69,666,115
107	S								
108	S	**EQUALS TOTAL COST OF SERVICE**		1,452,575,331	692,319,743	569,448,755	394,929	79,903,557	110,508,346
109	S								
110	S	**LESS:**							
111	S	Other Operating Revenues	CALCULATED	67,687,036	9,775,057	55,172,879	5,295	1,110,298	1,623,507
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
114	S	**EQUALS:**							
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
116	S								
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	0	1,127,751	0	12,410,339	2,763,212
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	283,770	206,454	51	0	277
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	0	52,043,670	0	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	0	52,043,670	0	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	0	19,575,233	0	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	0	19,575,233	0	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	PEAKHOUR_04	5,421,128	0	5,421,128	0	0	0
37	RBP	G366 Structures & Improvements	PEAKHOUR_04	0	0	0	0	0	0
38	RBP	G367 Mains	PEAKHOUR_04	93,786,847	0	93,786,847	0	0	0
39	RBP	G369 Meas. & Reg. Station Equipment	PEAKHOUR_04	4,336,420		4,336,420			
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	0	103,544,395	0	0	0
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	PEAKHOUR_04	3,772,391,917	0	3,772,391,917	0	0	0
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	0	2,792,974	0	0	0
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	0	3,775,184,891	0	0	0
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	PEAKHOUR_04	285,986,290	0	285,986,290	0	0	0
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	0	285,986,290	0	0	0
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	5,442,013,091	0	0	0	0
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	5,166,608	0	0	0	0
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	5,447,179,699	0	0	0	0
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	0	0	0	0	477,045,042
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	0	0	0	0	3,005
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	0	0	0	0	477,048,047
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	0	0	0	0	52,630,927
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	0	0	0	0	609
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	0	0	0	0	52,631,537
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	38,488,025	0	0	0	0
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	11,098	0	0	0	0
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	38,499,123	0	0	0	0
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	112,681,544	0	0	0	0
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,870	0	0	0	0
101	RBP	Total Account G384		112,683,414	112,683,414	0	0	0	0
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	71,912,204	0	0	0	0
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	0	0	0	71,912,204
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	895,023	0	0	0	0
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	0	0	0	0	895,023
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	72,807,227	0	0	0	72,807,227
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	1,011,930	0	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	509,787	0	0	0	0
115	RBP	Total Accounts G387		1,521,717	509,787	0	1,011,930	0	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	0	65,215,073	0	0	0
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	116,163,890	84,514,137	20,726	0	113,444
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	116,163,890	84,514,137	20,726	0	113,444
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
152	RBP	Not Used	not_used	0	0	0	0	0	0
153	RBP	Customer Service Related	CUSTSVSX	75,768,117	0	5,241,765	0	57,683,000	12,843,352
154	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	14,504,288	10,552,482	2,588	0	14,165
155	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
156	RBP	Unassigned	TOTPLT	1,393,316	742,218	563,006	132	8,885	79,075
157	RBP	Total Accounts C389-C399		102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
158	RBP								
159	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
160	RBP								
161	RBP								
162	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	0	679,475	0	7,477,281	1,664,847
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	0	679,475	0	7,477,281	1,664,847
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	0	679,475	0	7,477,281	1,664,847
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	0	56,077,402	0	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	0	9,476,790	0	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	0	50,246,121	0	0	0
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	235,779	171,539	42	0	25,046
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	PEAKHOUR_04	1,017,890,245	0	1,017,890,245	0	0	0
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	0	759,994	0	0	0
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	0	1,018,650,239	0	0	0
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	PEAKHOUR_04	93,669,010	0	93,669,010	0	0	0
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	0	93,669,010	0	0	0
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	1,126,944,013	0	0	0	0
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	2,349,910	0	0	0	0
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	1,129,293,923	0	0	0	0
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	0	0	0	0	61,006,069
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	0	0	0	0	1,948
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	0	0	0	0	61,008,018
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	0	0	0	0	33,652,945
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	0	0	0	0	279
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	0	0	0	0	33,653,224
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	25,030,964	0	0	0	0
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	4,827	0	0	0	0
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	25,035,791	0	0	0	0
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	58,406,745	0	0	0	0
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	1,006	0	0	0	0
75	RBD	Total Account G384		58,407,752	58,407,752	0	0	0	0
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	12,236,618	0	0	0	0
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	0	0	0	12,236,618
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	295,977	0	0	0	0
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	0	0	0	0	295,977
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	12,532,595	0	0	0	12,532,595
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,225,505,840	1,112,490,788	42	0	107,218,883

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	54,925,656	39,960,735	9,800	0	53,640
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	54,925,656	39,960,735	9,800	0	53,640
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Meter Reading Related	MRCOST_07	0	0	0	0	0	0
107	RBD	Not Used	not_used	0	0	0	0	0	0
108	RBD	Customer Service Related	CUSTSVSX	38,276,434	0	2,648,028	0	29,140,219	6,488,187
109	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	7,597,973	5,527,846	1,356	0	7,420
110	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
111	RBD	Unassigned	TOTPLT	1,273,650	678,472	514,652	121	8,122	72,284
112	RBD	Total Accounts C389-C399 Reserve		52,684,679	8,276,445	8,690,526	1,477	29,148,341	6,567,890
113	RBD								
114	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
115	RBD								
116	RBD								
117	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
118	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	31,847,963	24,145,283	5,682	0	3,383,121
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	605,321,561	296,196,284	219,311,794	133,855	36,751,550	52,928,077
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	56,614	41,919	26	7,025	10,117
11	RBO	Total Working Capital		664,819,310	328,100,861	243,498,996	139,563	36,758,575	56,321,315
12	RBO	CEF-EC Adjustment	not_used	0	0	0	0	0	0
13	RBO	CEF-EV Adjustment	not_used	0	0	0	0	0	0
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,583,894,314	863,652,841	628,343,927	154,091	0	91,743,454
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Plant Held for Future Use	TOTPLT	96,280	51,288	38,905	9	614	5,464
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	141,023,603	77,840,051	53,931,020	17,614	570,540	8,664,379
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,389,833,506	1,269,645,041	925,812,847	311,277	37,329,728	156,734,612
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	-24,945,102	-14,734,362	-10,210,740	0	0	0
23	RBO	IAP Adjustment	not_used	0	0	0	0	0	0
24	RBO	GSMP II EXT Adjustment	TOTPLT	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	18,845,647	14,295,283	3,362	225,601	2,007,791
28	RBO	Liberalized Depreciation - Production	BALANCE_04	-1,955,963	0	-1,955,963	0	0	0
29	RBO	Cost of Removal	TOTPLT	9,569,770	5,097,804	3,866,917	910	61,026	543,114
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	-160,793	-88,752	-61,491	-20	-651	-9,879
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	2,296,594	1,597,975	552	33,046	266,745
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	-1,761,556,867	-938,379,059	-711,803,340	-167,424	-11,233,345	-99,973,699
35	RBO	Total Deferred Income Taxes and Credits		-1,714,531,256	-912,227,766	-694,060,619	-162,620	-10,914,323	-97,165,928
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		-1,995,608,367	-1,063,403,317	-807,768,228	-186,964	-12,547,662	-111,702,197
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,668,832,235	4,773,532,754	3,282,465,244	1,157,811	58,258,668	553,417,758

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	493,590	772,544	0	39,084	141,996
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	0	40,880,111	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	9,281,467	7,634,218	5,295	1,071,213	1,481,511
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	0	5,886,006	0	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	9,775,057	55,172,879	5,295	1,110,298	1,623,507
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,452,575,331	692,319,743	569,448,755	394,929	79,903,557	110,508,346

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	0	281,982	0	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	0	29,792,635	0	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	0	1,832,256	0	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	0	31,906,873	0	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72		72			
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72		72			
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	0	31,906,945	0	0	0
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	0	8,906	0	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699		2,705,699			
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	0	2,714,605	0	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507		2,593,507			
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	0	2,593,507	0	0	0
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	0	5,839,316	0	0	0
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	12,246,734	8,486,843	0	0	0
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	0	2,497,019	0	0	0
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	0	7,594	0	0	0
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	0	514,539	0	0	0
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	2,551,763	0	0	0	8,940,298
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	0	17,355,157	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	3,625,445	8,234,483	0	0	2,190,260
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	0	-1,088,602	0	0	0
49	E	Total Distribution Operation		71,400,849	18,423,942	41,846,349	0	0	11,130,558
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	4,371,143	3,180,191	780	0	464,334
55	E	G887 Mains	PLT_376	8,706,285	0	8,706,285	0	0	0
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	0	1,007,898	0	0	0
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	0	3,155,564	0	0	0
59	E	G892 Services	SERVICES	3,610,466	3,610,466	0	0	0	0
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	0	0	0	0	6,767,990
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	2,413	4,853	60	0	2,187
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	198,384	0	0
67	E	Total Distribution Maintenance		31,472,549	7,984,022	16,054,791	199,225		7,234,511
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	26,407,965	95,116,197	199,225	0	18,365,069
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	0	0	0	0	12,907,838
76	E	- Meter O&M Related	METERPLT	38,249	0	0	0	0	38,249
77	E	- Remaining	MRCOST_07	0	0	0	0	0	0
78	E	G903 Customer Records and Collection							
79	E	- SONP/RNP	CUSTAVG_06	526,534	0	0	0	526,534	0
80	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
81	E	- Meter Reading Related	MRCOST_07	63,202	0	0	0	0	63,202
82	E	- Billing Related	BILLING_06	16,558,655	0	0	0	16,558,655	0
83	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	0	0	0	26,073,286	0
84	E	- Utility Work Related	UTILWORK_04	2,712,621	0	2,712,621	0	0	0
85	E	- Remaining	BILLING_06	13,832,442	0	0	0	13,832,442	0
86	E	Not used	not_used	0	0	0	0	0	0
87	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
88	E								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G904 Uncollectible Accounts	EXP_904	26,046,715	12,840,193	9,675,567	0	1,482,374	2,048,580
90	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
91	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	12,840,193	12,388,188	0	58,473,292	15,057,869
92	E								
93	E	CUSTOMER SERVICE & INFO EXPENSES							
94	E	G907 & 908 - Customer Service & Information							
95	E	- Billing	BILLING_06	37,379	0	0	0	37,379	0
96	E	- Acct Maint related	ACCTMAINT_06	746,413	0	0	0	746,413	0
97	E	- Utility work related	UTILWORK_04	1,684,915	0	1,684,915	0	0	0
98	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
99	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
100	E	G910 - Misc Cust Service & Info							
101	E	- Utility work related	UTILWORK_04	911,953	0	911,953	0	0	0
102	E	- Remaining	ACCTMAINT_06	653,558				653,558	
103	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	0	2,596,868	0	1,437,350	0
104	E								
105	E	SALES EXPENSES							
106	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	0	88,423	0	0	0
107	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
108	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
109	E								
110	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	0	88,423	0	0	0
111	E								
112	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	39,248,158	110,189,676	199,225	59,910,641	33,422,938
113	E								
114	E	ADMINISTRATIVE & GENERAL EXPENSE							
115	E	G920 A&G Salaries	LABOR	6,954,680	641,530	3,827,366	3,233	1,587,418	895,133
116	E	G921 Office Supplies & Exp	LABOR	652,569	60,196	359,128	303	148,950	83,992
117	E	G923 Outside Services Employed							
118	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
119	E	- Remaining	TOMXFUEL904	61,043,177	8,962,544	22,727,943	70,246	19,103,492	10,178,952
120	E	G924 Property Insurance	TOTPLT	296,480	157,935	119,801	28	1,891	16,826
121	E	G925 Injuries & Damages	LABOR	15,351,785	1,416,115	8,448,541	7,136	3,504,073	1,975,921
122	E	G926 Employee Pension & Benefits							
123	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
124	E	- Remaining	LABOR	-60,778,346	-5,606,456	-33,448,121	-28,250	-13,872,767	-7,822,751
125	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	0	5,147,284	0	0	0
126	E	G929 Duplicate Charges - credit	INTRAREV	764,611	196,940	509,867	0	15,804	42,000
127	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	0	1,968,152	0	0	0
128	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	0	3,638,524	0	0	0
129	E	G931 Rents	AGEXP	3,713,155	617,692	1,409,271	5,584	1,111,529	569,079
130	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
131	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
132	E	Not Used	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	E	TOTAL A&G EXPENSE		38,752,071	6,446,494	14,707,756	58,280	11,600,390	5,939,152
134	E								
135	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	45,694,652	124,897,432	257,504	71,511,031	39,362,089
136	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	0	1,670	0	0	0
5	DE	Storage Plant	BALANCE_04	114,612	0	114,612	0	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	0	1,172,631	0	0	0
7	DE	Distribution Plant	DISTPLT	182,874,076	99,716,069	72,547,653	17,791	0	10,592,562
8	DE	General and Common Plant	COMGENPLT	19,528,227	8,468,029	6,500,109	1,511	3,717,640	840,939
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	0	82,628	0	909,279	202,455
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	DISTPLT	1,127,553	614,823	447,310	110	0	65,311
16	DE	Metering	METERPLT	29,719	0	0	0	0	29,719
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	614,823	529,938	110	909,279	297,484
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	614,823	529,938	110	909,279	297,484
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	108,798,921	80,866,612	19,412	4,626,919	11,730,985

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-188	-1,119	-1	-464	-262
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-7,219,321	-5,476,185	-1,288	-86,423	-769,137
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-5,579	-33,284	-28	-13,805	-7,784
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-1,002,313	-5,979,800	-5,051	-2,480,151	-1,398,539
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-8,227,401	-11,490,389	-6,368	-2,580,842	-2,175,722
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-682,298	-62,938	-375,489	-317	-155,736	-87,818
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	4,884,054	2,407,115	1,813,685	1,374	277,878	384,002
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	6,746,929	622,366	3,713,035	3,136	1,539,999	868,394
26	EO	Payroll Taxes (Rate Year)	LABOR	463,867	42,789	255,280	216	105,879	59,704
27	EO	Interest Syncronization	TOTPLTNET	-1,266,764	-699,209	-484,443	-158	-5,125	-77,829
28	EO	- add'l tax effects on rev req	TOTPLTNET	-495,322	-273,400	-189,424	-62	-2,004	-30,432
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	15,610,563	1,439,986	8,590,955	7,256	3,563,139	2,009,228
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	0	0	0	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-110,508	-83,826	-20	-1,323	-11,773
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-43,210	-32,777	-8	-517	-4,604
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	-328,894	-175,201	-132,898	-31	-2,097	-18,666
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	262,863	140,027	106,217	25	1,676	14,918
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-3,160,368	-2,397,283	-564	-37,833	-336,702
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	14,761,516	7,863,441	5,964,779	1,403	94,133	837,761
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	150,424	80,131	60,783	14	959	8,537
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	71,386,007	37,914,403	28,154,942	6,765	1,302,891	4,007,006
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		105,999,447	46,052,558	45,364,074	19,367	6,848,045	7,715,403
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		81,518,725	37,825,157	33,873,685	12,999	4,267,203	5,539,681
61	EO	COLI Interest Expense Recovery	LABOR	727,815	67,137	400,538	338	166,125	93,677

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,452,575,331	692,319,743	569,448,755	394,929	79,903,557	110,508,346
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	45,694,652	124,897,432	257,504	71,511,031	39,362,089
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	108,798,921	80,866,612	19,412	4,626,919	11,730,985
7	TI	OTHER OPERATING EXPENSES	CALCULATED	81,518,725	37,825,157	33,873,685	12,999	4,267,203	5,539,681
8	TI	NET OPERATING INCOME BEFORE TAXES		883,291,047	500,001,013	329,811,026	105,014	-501,596	53,875,590
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	55,649,119	38,556,163	12,592	407,888	6,194,306
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		782,470,979	444,351,894	291,254,863	92,422	-909,484	47,681,284
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	31,342	21,715	7	230	3,489
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	28,843	19,984	7	211	3,211
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	222,078	168,456	40	2,658	23,660
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-604,844	-419,062	-137	-4,433	-67,325
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP II	TOTPLT	8,262	4,401	3,338	1	53	469
23	TI	Deferred Return on CIP II	TOTPLT	18,055	9,618	7,296	2	115	1,025
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-230,728	-159,858	-52	-1,691	-25,682
31	TI	Material Supplies & Reserves	TOTPLT	78,535	41,836	31,734	7	501	4,457
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-251,528	-174,269	-57	-1,844	-27,998
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-179,515	-124,376	-41	-1,316	-19,982
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-7	-6	0	0	-1
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	4,148	3,146	1	50	442
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-32,493	-193,851	-164	-80,401	-45,337
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-1,344	-8,018	-7	-3,326	-1,875
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-11,563,231	-8,586,766	-2,063	-397,359	-1,222,067
60	TI	Customer Advances	TOTPLTNET	294,687	162,657	112,696	37	1,192	18,105
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-404	-2,410	-2	-999	-564
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-534,856	-3,190,953	-2,695	-1,323,463	-746,291
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	494	375	0	6	53
65	TI	Entertainment (100%)	LABOR	36,298	3,348	19,976	17	8,285	4,672
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	556,541	422,162	99	6,662	59,293
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-32,878,422	-24,415,262	-5,866	-1,129,835	-3,474,776
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	12,858	76,708	65	31,815	17,940
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-40,335	-30,596	-7	-483	-4,297
75	TI	R&D Expenditure	TOTPLT	-16,866	-8,984	-6,815	-2	-108	-957
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-276,657	-209,857	-49	-3,312	-29,475
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	316,947	240,419	57	3,794	33,767
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	11,235	67,025	57	27,799	15,676
81	TI	State NOL CF (c)	DEPREXP	7,732,062	4,106,638	3,049,558	733	141,121	434,013
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-43,195	-32,765	-8	-517	-4,602
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	75,722	57,439	14	906	8,067
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	EXP_904	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-42,359	-252,715	-213	-104,815	-59,104
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-466,217	-323,016	-105	-3,417	-51,895
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Book Depreciation	DEPREXP	0	0	0	0	0	0
95	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
96	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
97	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
98	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
99	TI	AFUDC / IDC	TOTPLT	-345,079	-183,823	-139,438	-33	-2,201	-19,584
100	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
101	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
102	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
103	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
104	TI	Deferred Comp - officers	LABOR	-15,155	-1,398	-8,340	-7	-3,459	-1,951
105	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
106	TI	Accrued vacation pay adjustment	LABOR	-257,985	-23,798	-141,977	-120	-58,886	-33,205
107	TI	3rd Party Claims	TOTPLT	-975	-519	-394	0	-6	-55
108	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
109	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
110	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
111	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-717,693	-4,281,758	-3,616	-1,775,879	-1,001,405
112	TI	Unallowable OPEB Amortization	LABOR	47,224,310	4,356,174	25,988,934	21,950	10,779,034	6,078,218
113	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
114	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
115	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	138,997	829,254	700	343,937	193,944
116	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
117	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
118	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
119	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
120	TI	Restricted Stock - Permanent	LABOR	-67,594	-6,235	-37,199	-31	-15,429	-8,700
121	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
122	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
123	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
124	TI	Penalties	not_used	0	0	0	0	0	0
125	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
126	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-563,726	-390,574	-128	-4,132	-62,748
127	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
128	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
129	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
130	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
131	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-38,568,435	-12,010,061	8,388	6,431,061	-9,377
132	TI								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI								
134	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
135	TI								
136	TI	**TAX ADJUSTMENTS - STATE**							
137	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
138	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	34,453,448	26,134,512	6,147	412,443	3,670,626
139	TI	State Tax Depreciation	DEPREXP	37,759,415	20,054,710	14,892,472	3,578	689,160	2,119,494
140	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
141	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
142	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	54,508,158	41,026,985	9,725	1,101,603	5,790,120
143	TI								
144	TI	**TAXABLE NET INCOME - STATE**		840,759,145	460,291,616	320,271,787	110,535	6,623,180	53,462,027
145	TI	State Tax Liability		75,668,323	41,426,245	28,824,461	9,948	596,086	4,811,582
146	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
147	TI	**TOTAL STATE INCOME TAX LIABILITY**		75,668,323	41,426,245	28,824,461	9,948	596,086	4,811,582
148	TI								
149	TI	**TAXABLE NET INCOME - FEDERAL**		662,654,232	364,357,213	250,420,341	90,862	4,925,491	42,860,325
150	TI	Federal Tax Liability		139,157,389	76,515,015	52,588,272	19,081	1,034,353	9,000,668
151	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
152	TI	Not Used	not_used	0	0	0	0	0	0
153	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		139,157,389	76,515,015	52,588,272	19,081	1,034,353	9,000,668
154	TI								
155	TI	**TOTAL INCOME TAX EXPENSE**		214,825,712	117,941,260	81,412,733	29,029	1,630,439	13,812,251
156	TI								
157	TI	**TAX RATES**							
158	TI	FEDERAL TAX RATE - CURRENT		21.000%					
159	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
160	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000					
161	TI	EFFECTIVE TAX RATE		28.110%					
162	TI	COMPOSITE RATE		28.110%					
163	TI	1 - EFFECTIVE TAX RATE		71.89000%					
164	TI								
165	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
166	TI								
167	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
168	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
169	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
170	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
171	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	7	6	0	0	1
172	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-16,911	-12,828	-3	-202	-1,802
173	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	604,844	419,062	137	4,433	67,325
174	TI	CECL Reserve	not_used	0	0	0	0	0	0
175	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
176	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
178	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
179	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
180	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
181	TI	COVID Deferrals	not_used	0	0	0	0	0	0
182	TI	Current SHARE -- FT	DEPREXP	5,506,769	2,924,745	2,171,893	522	100,506	309,103
183	TI	Customer Advances	TOTPLTNET	-294,687	-162,657	-112,696	-37	-1,192	-18,105
184	TI	Deduction for Retention Payments (c)	LABOR	4,379	404	2,410	2	999	564
185	TI	Deferred Employer ER FICA	LABOR	5,798,258	534,856	3,190,953	2,695	1,323,463	746,291
186	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
187	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
188	TI	Injuries & Damages - FT	TOTPLT	-264,256	-140,769	-106,780	-25	-1,685	-14,997
189	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
190	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
191	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
192	TI	Plant Related	DEPREXP	62,706,788	33,304,712	24,731,822	5,942	1,144,484	3,519,828
193	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
194	TI	R & D Credits CF	TOTPLT	-67,859	-36,148	-27,420	-6	-433	-3,851
195	TI	RE - Lease Liability	TOTPLT	519,350	276,657	209,857	49	3,312	29,475
196	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-316,947	-240,419	-57	-3,794	-33,767
197	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	544,049	412,686	97	6,513	57,962
198	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
199	TI	Severance Pay (nc)	LABOR	-121,791	-11,235	-67,025	-57	-27,799	-15,676
200	TI	State NOL CF (c)	DEPREXP	-7,732,062	-4,106,638	-3,049,558	-733	-141,121	-434,013
201	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-75,722	-57,439	-14	-906	-8,067
202	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
203	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
204	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
205	TI	AFUDC / IDC	TOTPLT	345,079	183,823	139,438	33	2,201	19,584
206	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-222,078	-168,456	-40	-2,658	-23,660
207	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
208	TI	Deferred Comp - officers	LABOR	15,155	1,398	8,340	7	3,459	1,951
209	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
210	TI	Accrued vacation pay adjustment	LABOR	257,985	23,798	141,977	120	58,886	33,205
211	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
212	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
213	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
214	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
215	TI	Pension Accrual Adjustment	LABOR	7,780,352	717,693	4,281,758	3,616	1,775,879	1,001,405
216	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-4,356,174	-25,988,934	-21,950	-10,779,034	-6,078,218
217	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
218	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
219	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
220	TI	PIP Adjustment	LABOR	455,695	42,035	250,782	212	104,013	58,652

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0
222	TI	Misc	TOTPLT	0	0	0	0	0	0
223	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
224	TI	Deferred Return on CIP II	TOTPLT	-18,055	-9,618	-7,296	-2	-115	-1,025
225	TI	Deferred Depreciation on CIP II	TOTPLT	-8,262	-4,401	-3,338	-1	-53	-469
226	TI	Investment Tax Credit	TOTPLT	-493,265	-262,762	-199,317	-47	-3,146	-27,994
227	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-31,342	-21,715	-7	-230	-3,489
228	TI	3rd Party Claims	TOTPLT	975	519	394	0	6	55
229	TI	Customer Connections Fees		0	0	0	0	0	0
230	TI	Legal Reserves (nc)	TOTPLTNET	418,012	230,728	159,858	52	1,691	25,682
231	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-43,349	-30,034	-10	-318	-4,825
232	TI	Stock Based Compensation	TOTPLTNET	325,229	179,515	124,376	41	1,316	19,982
233	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	29,773,035	6,152,359	-9,462	-6,431,525	-778,891
234	TI								
235	TI	**This Section is not used at this time**							
236	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	Not Used	not_used	0	0	0	0	0	0
240	TI	**OPERATING INCOME ADJUSTED**		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	0	778,312	0	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	0	407,976	0	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	0	483,267	0	0	0
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	0	4,522,112	0	0	0
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	8,477,124	5,874,548	0	0	0
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	0	1,368,583	0	0	0
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	1,901,176	0	0	0	6,660,916
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	0	63,057,319	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	1,346,785	3,058,957	0	0	813,641
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	0	-60	0	0	0
21	LR	Total Operation		97,081,101	11,725,086	77,881,458	0	0	7,474,557
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	553,706	402,845	99	0	58,819
26	LR	G887 Mains	EXP_887	4,445,965	0	4,445,965	0	0	0
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	0	2,185,363	0	0	0
29	LR	G892 Services	EXP_892	2,126,460	2,126,460	0	0	0	0
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	0	0	0	0	5,044,535
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	825	1,659	67,862	0	748
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	2,680,991	7,035,832	67,960		5,104,101
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	14,406,077	84,917,290	67,960	0	12,578,658
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	0	1,682,855	0	35,356,012	8,070,699
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	0	1,936,120	0	1,071,630	0
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	0	3,526	0	0	0
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	1,156,927	2,639,542	10,459	2,081,876	1,065,876
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	15,563,004	92,848,889	78,420	38,509,518	21,715,234

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	0	-2,267,387	0	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	0	8,371,561	0	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	0	11	0	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improveme	PLT_3745	2,620,552	1,428,913	1,039,595	255	0	151,789
10	CA	G376 Mains	PLT_376	226,633,216	0	226,633,216	0	0	0
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	0	57,069,064	0	0	0
13	CA	G380 Services	SERVICES	505,466,924	505,466,924	0	0	0	0
14	CA	G381 Meters	PLT_381	58,899,779	0	0	0	0	58,899,779
15	CA	G382 Meter Installations	PLT_382	-1,810,761	0	0	0	0	-1,810,761
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,268,333	0	0	0	0
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	6,369,606				6,369,606
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	515,533,776	284,741,875	255	0	63,610,413
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	15,109,213	10,992,591	2,696	0	14,755
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	530,642,989	301,838,650	2,951	0	63,625,169

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	0	124,747	0	0	0
6	AF								
7	AF	**COMMODITY RELATED**							
8	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	0	2,598,285,838	0	0	0
9	AF	Balancing therms - delivery	BALANCE_04	1,793,060	0	1,793,060	0	0	0
10	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	2,598,285,838	0	0	0	0
11	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	0	0	0	0	2,598,285,838
12	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
13	AF								
14	AF	**BILLING DETERMINANTS**							
15	AF	Number of Customers		1,894,095	1,894,095	1,894,095	1,894,095	1,894,095	1,894,095
16	AF	Transported Gas at Meter (calendar)		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
17	AF								
18	AF								
19	AF	**CUSTOMER RELATED**							
20	AF	G380 services - access	SERVICES_03	1,215,746,207	1,215,746,207	0	0	0	0
21	AF	Cust Installns LDC G879 - delivery	CINST_04	100	0	100	0	0	0
22	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	0	661,048	0	0	0
23	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	0	0	0	661,048	0
24	AF	G381 meters - measurement	SMMETERS_07	95,373,410	0	0	0	0	95,373,410
25	AF								
26	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	0	0	0	20,835,825	0
27	AF	Competitive Service work - delivery	COMPSVSWK_04	100	0	100	0	0	0
28	AF								
29	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	0	0	0	67,192,728	0
30	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,257	0	0	0	0	149,490,257
31	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	27,726,351	0	0	0	0
32	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	49,550,462	0	0	0	0
33	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	42,370,365	0	0	0	0
34	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	0	0	0	6,790,868
35	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	302,262,539	0	0	0	0
36	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	0	0	0	0	39,637,552
37	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	0	0	0	0	70,947,597
38	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	4,745,170	0	0	0	0
39	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,880,504	0	0	0	0
40	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	6,940,251	0	0	0	0
41	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	0	0	0	1,112,795
42	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
43	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0
44	AF	ALLOCATION FACTOR TABLE							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
46	AF								
47	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	1	0	0
48	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	0	0	0	0	16,284,753
49	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	0	6,776,917	0	0	0
50	AF	Direct SLG - access	DIRSLG_03	1	1	0	0	0	0
51	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
52	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
53	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
54	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
55	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
56	AF	Choice - delivery	CHOICE_04	1,894,095	0	1,894,095	0	0	0
57	AF								
58	AF								
59	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
60	AF								
61	AF								
62	AF	**Plant Related**							
63	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
64	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
65	AF	Production Plant Total	PRODPLT	52,043,670	0	52,043,670	0	0	0
66	AF	Storage Plant Total	STORPLT	19,575,233	0	19,575,233	0	0	0
67	AF	Transmission Plant Total	TRANPLT	103,544,395	0	103,544,395	0	0	0
68	AF	Distribution Plant Total	DISTPLT	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
69	AF	G391-G398 General Plant	GENPLT	200,812,197	116,163,890	84,514,137	20,726	0	113,444
70	AF	Common Plant	COMPLT	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
71	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
72	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	5,724,304,805	4,339,836,866	1,021,319	0	608,077,078
73	AF	Total Plant	TOTPLT	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
74	AF								
75	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	5,724,304,805	4,164,673,568	1,021,319	0	5,590,267
76	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
77	AF	Acct G376 - Mains	PLT_376	3,775,184,891	0	3,775,184,891	0	0	0
78	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
79	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	0	285,986,290	0	0	0
80	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	5,447,689,486	0	0	0	0
81	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	5,447,689,486	3,775,184,891	0	0	0
82	AF	Acct G381 - House Meters	PLT_381	477,048,047	0	0	0	0	477,048,047
83	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	0	0	0	0	52,631,537
84	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	0	0	0	0	602,486,811
85	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	151,182,537	0	0	0	529,679,583
86	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	151,182,537	0	0	0	52,631,537
87	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	151,182,537	0	0	0	0
88	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AF								
91	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	72,807,227	0	0	0	72,807,227
92	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
93	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	1,011,930	0	0
94	AF								
95	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
96	AF	Total Net Plant	TOTPLTNET	8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
97	AF								
98	AF								
99	AF	**Revenue Related**							
100	AF	Total Operating Revenue	TOTREV	1,452,575,331	692,319,743	569,448,755	394,929	79,903,557	110,508,346
101	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	191,712,321	49,379,169	127,839,884	0	3,962,621	10,530,647
102	AF								
103	AF								
104	AF	**Expense Related**							
105	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	0	2,114,238	0	0	0
106	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	0	2,714,605	0	0	0
107	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	0	2,593,507	0	0	0
108	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	0	72	0	0	0
109	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	0	5,839,316	0	0	0
110	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
111	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	12,246,734	8,486,843	0	0	0
112	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	0	3,019,152	0	0	0
113	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	2,551,763	0	0	0	8,940,298
114	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	0	17,355,157	0	0	0
115	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	3,625,445	8,234,483	0	0	2,190,260
116	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
117	AF	Acct 881 - Rents	EXP_881	-1,088,602	0	-1,088,602	0	0	0
118	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	4,371,143	3,180,191	780	0	464,334
119	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	0	8,706,285	0	0	0
120	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
121	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	0	4,163,462	0	0	0
122	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	3,610,466	0	0	0	0
123	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	0	0	0	0	6,767,990
124	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	2,413	4,853	198,445	0	2,187
125	AF								
126	AF	Distr Oper Exp	DISTEXPO	71,400,849	18,423,942	41,846,349	0	0	11,130,558
127	AF	Distr Maint Exp	DISTEXPM	31,472,549	7,984,022	16,054,791	199,225	0	7,234,511
128	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	0	2,596,868	0	1,437,350	0
129	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	0	2,712,621	0	56,990,917	13,009,288
130	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	0	5,309,489	0	58,428,267	13,009,288
131	AF	Sales Expense	SALESEXP	88,423	0	88,423	0	0	0
132	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
134	AF								
135	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	39,248,158	110,189,676	199,225	59,910,641	33,422,938
136	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	32,854,459	115,221,864	257,504	70,028,657	37,313,509
137	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	32,854,459	83,314,991	257,504	70,028,657	37,313,509
138	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	6,446,494	14,707,756	58,280	11,600,390	5,939,152
139	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	0	2,712,621	0	56,990,917	13,009,288
140	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	576,337,641	426,736,082	260,455	71,511,031	102,987,258
141	AF								
142	AF	Depreciation Expense (total)	DEPREXP	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
143	AF								
144	AF	NJ State Income Tax (CBT)	STATEINCTAX	75,668,323	41,426,245	28,824,461	9,948	596,086	4,811,582
145	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-3,638,480	-21,707,176	-18,334	-9,003,155	-5,076,813
146	AF								
147	AF	**Labor Expense Related**							
148	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	11,725,086	77,881,458	0	0	7,474,557
149	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	2,680,991	7,035,832	67,960	0	5,104,101
150	AF	Total Labor	LABOR	168,715,063	15,563,004	92,848,889	78,420	38,509,518	21,715,234
151	AF								
152	AF	**REVENUES AND BILLING DETERMINANTS**							
153	AF								
154	AF	Base Rate Sales Revenue	SALESREV	1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
155	AF								
156	AF	Residential Service Gas	REVRSG	1,004,672,106	555,299,629	310,140,108	0	66,994,808	72,237,560
157	AF	General Service Gas	REVGSG	179,159,859	79,138,304	66,907,735	0	6,207,195	26,906,625
158	AF	Large Volume Service Gas	REVLVG	192,459,776	47,607,116	131,468,181	0	3,828,965	9,555,515
159	AF	Street Light Gas	REVSLG	470,028	70,976	6,330	389,635	3,063	24
160	AF	Firm Transportation Gas Service	REVTSGF	8,126,527	428,660	5,753,523	0	1,759,229	185,115
161	AF								
162	AF								
163	AF	Total Rev Req @ desired ROR	REVREQ	1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
164	AF								
165	AF								
166	AF	**PRESENT REVENUES FROM SALES INPUT**							
167	AF								
168	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
169	AF	Sales of Gas Revenues - Rates		1,101,761	1,101,761	1,101,761	1,101,761	1,101,761	1,101,761
170	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
171	AF								
172	AF	**RATE OF RETURN**							
173	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
6	AP								
7	AP	**COMMODITY RELATED**							
8	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
9	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
10	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
11	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
12	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	AF								
14	AP	**BILLING DETERMINANTS**							
15	AP	Number of Customers		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
16	AP	Transported Gas at Meter (calendar)		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
17	AP								
18	AP								
19	AP	**CUSTOMER RELATED**							
20	AP	G380 services - access	SERVICES_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
21	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
22	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
24	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
25	AP								
26	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
27	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
28	AF								
29	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
30	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
31	AP	G383 house regulators - access	HOUSEREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
32	AP	G384 house reg install - access	HSEREGINST_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
33	AP	G385 lrg regulators - access	LRGREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
34	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
35	AP	G380 services - reserve - access	SERVICESR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
36	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
37	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
38	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
39	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
40	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
41	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
42	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
46	AP								
47	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
48	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
49	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
50	AP	Direct SLG - access	DIRSLG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
51	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Choice - delivery	CHOICE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
57	AP								
58	AP								
59	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
60	AP								
61	AP								
62	AP	**Plant Related**							
63	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
64	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.016899	0.079456	0.000003	0.739069	0.164573
65	AP	Production Plant Total	PRODPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
66	AP	Storage Plant Total	STORPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
67	AP	Transmission Plant Total	TRANPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
68	AP	Distribution Plant Total	DISTPLT	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
69	AP	G391-G398 General Plant	GENPLT	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
70	AP	Common Plant	COMPLT	1.000000	0.149132	0.159997	0.000027	0.564307	0.126538
71	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.433630	0.332857	0.000077	0.190373	0.043063
72	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.536323	0.406609	0.000096	0.000000	0.056972
73	AP	Total Plant	TOTPLT	1.000000	0.532699	0.404076	0.000095	0.006377	0.056753
74	AP								
75	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
76	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
77	AP	Acct G376 - Mains	PLT_376	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
78	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
79	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
80	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
81	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
82	AP	Acct G381 - House Meters	PLT_381	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
83	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
84	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
85	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
86	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.741767	0.000000	0.000000	0.000000	0.258233
87	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
88	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
90	AP								
91	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.500000	0.000000	0.000000	0.000000	0.500000
92	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
93	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
94	AP								
95	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.474056	0.469978	0.000004	0.013473	0.042489
96	AP	Total Net Plant	TOTPLTNET	1.000000	0.551965	0.382425	0.000125	0.004046	0.061439
97	AP								
98	AP								
99	AP	**Revenue Related**							
100	AP	Total Operating Revenue	TOTREV	1.000000	0.476615	0.392027	0.000272	0.055008	0.076078
101	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.257569	0.666832	0.000000	0.020670	0.054929
102	AP								
103	AP								
104	AP	**Expense Related**							
105	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
106	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
107	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
108	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
109	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
110	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
111	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
112	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
113	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
114	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
115	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
116	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
117	AP	Acct 881 - Rents	EXP_881	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
118	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
119	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
120	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
121	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
122	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
123	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
124	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.011608	0.023342	0.954532	0.000000	0.010518
125	AP								
126	AP	Distr Oper Exp	DISTEXPO	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
127	AP	Distr Maint Exp	DISTEXPM	1.000000	0.253682	0.510120	0.006330	0.000000	0.229867
128	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.643710	0.000000	0.356290	0.000000
129	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
130	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.069182	0.000000	0.761310	0.169509
131	AP	Sales Expense	SALESEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
132	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.161535	0.453510	0.000820	0.246576	0.137560

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.128500	0.450656	0.001007	0.273896	0.145941
134	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.146823	0.372326	0.001151	0.312950	0.166750
135	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.166352	0.379535	0.001504	0.299349	0.153260
136	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
137	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.489321	0.362306	0.000221	0.060714	0.087438
138	AP								
139	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.531118	0.394404	0.000095	0.018251	0.056132
140	AP								
141	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.547471	0.380932	0.000131	0.007878	0.063588
142	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.092244	0.550330	0.000465	0.228252	0.128710
143	AP								
144	AP	**Labor Expense Related**							
145	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.120776	0.802231	0.000000	0.000000	0.076993
146	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.180067	0.472556	0.004565	0.000000	0.342813
147	AP	Total Labor	LABOR	1.000000	0.092244	0.550330	0.000465	0.228252	0.128710
148	AP								
149	AP	**REVENUES AND BILLING DETERMINANTS**							
150	AP								
151	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.492852	0.371348	0.000281	0.056895	0.078624
152	AP								
153	AP	Residential Service Gas	REVRSG	1.000000	0.552717	0.308698	0.000000	0.066683	0.071902
154	AP	General Service Gas	REVGSG	1.000000	0.441719	0.373453	0.000000	0.034646	0.150182
155	AP	Large Volume Service Gas	REVLVG	1.000000	0.247361	0.683094	0.000000	0.019895	0.049649
156	AP	Street Light Gas	REVSLG	1.000000	0.151005	0.013466	0.828962	0.006516	0.000051
157	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.052748	0.707993	0.000000	0.216480	0.022779
158	AP								
159	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.492852	0.371348	0.000281	0.056895	0.078624
160	AP								
161	AP	**PRESENT REVENUES FROM SALES INPUT**							
162	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
163	AP	Sales of Gas Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
164	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	1,004,672,106	555,299,629	310,140,108	0	66,994,808	72,237,560
6	ADA	General Service Gas	REVGSG	179,159,859	79,138,304	66,907,735	0	6,207,195	26,906,625
7	ADA	Large Volume Service Gas	REVLVG	192,459,776	47,607,116	131,468,181	0	3,828,965	9,555,515
8	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
9	ADA	Firm Transportation Gas Service	REVTSGF	8,126,527	428,660	5,753,523	0	1,759,229	185,115
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,384,418,267	682,473,710	514,269,546	0	78,790,197	108,884,815
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.492968	0.371470		0.056912	0.078650
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	179,159,859	79,138,304	66,907,735	0	6,207,195	26,906,625
20	ADA	Large Volume Service Gas	REVLVG	192,459,776	47,607,116	131,468,181	0	3,828,965	9,555,515
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	371,619,635	126,745,420	198,375,915	0	10,036,160	36,462,140
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.341062	0.533814		0.027007	0.098117
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	----------							
5	RRW	RATE BASE		8,668,832,235	4,773,532,754	3,282,465,244	1,157,811	58,258,668	553,417,758
6	RRW	NET OPER INC (PRESENT RATES)		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
10	RRW	REVENUE PRES RATES $/THERM		$0.5330	$0.2627	$0.1979	$0.0001	$0.0303	$0.0419
11	RRW	REVENUE REQUIRED - $/MO/CUST		$60.93	$30.03	$22.63	$0.02	$3.47	$4.79
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	----------							
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		639,759,819	352,286,717	242,245,935	85,446	4,299,490	40,842,231
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,384,888,295	682,544,686	514,275,876	389,635	78,793,260	108,884,838
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
22	RRW	SALES REV REQUIRED $/THERM		$0.5330	$0.2627	$0.1979	$0.0001	$0.0303	$0.0419
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company	RSG	GSG	LVG	SLG	TSG-F
		(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Access	$682,583,473	$555,333,136	$79,151,593	$47,599,123	$70,977	$428,644
2	Distribution Delivery	$512,783,972	$295,593,534	$63,136,630	$148,918,700	$87,554	$5,047,555
3	Street Lighting	$397,774				$397,774	
4	Customer Service	$79,837,037	$67,789,982	$6,293,710	$3,934,158	$3,157	$1,816,030
5	Measurement	$109,286,039	$72,565,512	$26,961,245	$9,574,256	$24	$185,003
6	Total	$1,384,888,295	$991,282,164	$175,543,177	$210,026,237	$559,485	$7,477,232

Cost of Service and Rate Design Sync

EXHIBIT P-9G
Schedule SS-G7
Page 1 of 2

Part 1: Cost of Service Study Results

line #		(1) Total	(2) RSG	(3) GSG	(4) LVG	(5) SLG	(6) TSG-F	Note:
	Functionalized Revenue Requirements							
1	Distribution Access	$ 682,544,686	555,299,629	79,138,304	47,607,116	70,976	428,660	SS-G6, line 1
2	Distribution Delivery	$ 514,275,876	310,140,108	66,907,735	131,468,181	6,330	5,753,523	SS-G6, line 2
3	Streetlighting Fixtures	$ 389,635	-	-	-	389,635	-	SS-G6, line 3
4	Customer Service	$ 78,793,260	66,994,808	6,207,195	3,828,965	3,063	1,759,229	SS-G6, line 4
5	Measurement	$ 108,884,838	72,237,560	26,906,625	9,555,515	24	185,115	SS-G6, line 5
6	Total	$ 1,384,888,295	$ 1,004,672,106	$ 179,159,859	$ 192,459,776	$ 470,028	$ 8,126,527	

Part 2: Redistribution of TSG-F Revenue Requirements

7	BGSS Therms Supplied - COS period	1,997,312,383	1,485,348,311	231,153,115	280,116,216	694,743	COS workpapers
8	% of Total BGSS Therms Supplied	100.0000%	74.3674%	11.5732%	14.0247%	0.0348%	= line 7 / line 7 Col 1 rounded to .0001%
	Redistribution of TSG-F Revenue Requirements						
9	Distribution Access	$ 428,660	$ 318,783	$ 49,610	$ 60,118	$ 149	= TSG-F line 1 * line 8
10	Distribution Delivery	$ 5,753,528	$ 4,278,745	$ 665,867	$ 806,914	$ 2,002	= TSG-F line 2 * line 8
11	Streetlighting Fixtures	$ -	$ -	$ -	$ -	$ -	= TSG-F line 3 * line 8
12	Customer Service	$ 1,759,231	$ 1,308,293	$ 203,599	$ 246,727	$ 612	= TSG-F line 4 * line 8
13	Measurement	$ 185,116	$ 137,666	$ 21,424	$ 25,962	$ 64	= TSG-F line 5 * line 8
14	Total	$ 8,126,535	$ 6,043,487	$ 940,500	$ 1,139,721	$ 2,827	
	Functionalized Revenue Requirements - Total						
15	Distribution Access	$ 682,544,686	$ 555,618,412	$ 79,187,914	$ 47,667,234	$ 71,125	= line 1 + line 9
16	Distribution Delivery	$ 514,275,881	$ 314,418,853	$ 67,573,602	$ 132,275,095	$ 8,332	= line 2 + line 10
17	Streetlighting Fixtures	$ 389,635	$ -	$ -	$ -	$ 389,635	= line 3 + line 11
18	Customer Service	$ 78,793,262	$ 68,303,101	$ 6,410,794	$ 4,075,692	$ 3,675	= line 4 + line 12
19	Measurement	$ 108,884,839	$ 72,375,226	$ 26,928,049	$ 9,581,477	$ 88	= line 5 + line 13
20	Total	$ 1,384,888,303	$ 1,010,715,593	$ 180,100,359	$ 193,599,497	$ 472,855	

Cost of Service and Rate Design Sync

EXHIBIT P-9G
Schedule SS-G7
Page 2 of 2

Part 3: Calculation of Sync Factors

line #		(7)	(8) RSG	(9) GSG	(10) LVG	(11) SLG	Notes:
1	# of Customers - Rate Design period		1,712,253	140,296	19,537	16	SS-G11
2	# of Customers - Cost of Service period		1,728,739	145,499	19,809	16	COS workpapers
3	Customer Sync Adjustment Factor		0.99046	0.96424	0.98627	1.00000	= line 1 / line 2
4	Therms Delivered - Rate Design period		1,542,270,094	296,701,695	752,946,120	711,043	SS-G11
5	Therms Delivered - Cost of Service period		1,542,348,577	293,860,816	759,845,113	694,743	COS workpapers
6	Delivery Sync Adjustment Factor		0.99995	1.00967	0.99092	1.02346	= line 4 / line 5
7	# of Streetlights - Rate Design period					2,586	SS-G11
8	# of Streetlights - Cost of Service period					2,501	COS Workpapers - SLG Analysis
9	Streetlight Sync Adjustment Factor					1.03405	= line 7 / line 8

Part 4: Initial Snyc

		Total	RSG	GSG	LVG	SLG	
10	Distribution Access	$ 673,759,809	550,319,796	76,356,178	47,012,709	71,125	= Page 1, line 15 * line 3
11	Distribution Delivery	$ 513,712,353	314,402,854	68,226,865	131,074,107	8,527	= Page 1, line 16 * line 6
12	Streetlighting Fixtures	$ 402,904	-	-	-	402,904	= Page 1, line 17 * line 9
13	Customer Service	$ 77,856,682	67,651,734	6,181,546	4,019,728	3,675	= Page 1, line 18 * line 3
14	Measurement	$ 107,100,134	71,685,024	25,965,110	9,449,912	88	= Page 1, line 19 * line 3
15	Total	$ 1,372,831,881	$ 1,004,059,408	$ 176,729,699	$ 191,556,456	$ 486,319	

Part 5: 2023 Base Rate Case Final Revenue Allocation

16	Requested increase in Revenue Requirements	$ 422,815,059	=SS-G8, pg 1, line 1 * 1000
17	Total Target Distribution Revenue Requirements	$ 1,567,567,905	=SS-G8, pg 2, line 11 * 1000
18	Sum of Initial Sync Revenue Requirements	$ 1,372,831,881	Total, col 7, line 15
19	Final Sync Adjustment Factor	1.14185	= line 17 / line 18

		Total	RSG	GSG	LVG	SLG	
20	Distribution Access	$ 769,332,638	$ 628,382,659	$ 87,187,302	$ 53,681,462	$ 81,215	= line 10 * line 19
21	Distribution Delivery	$ 586,582,450	$ 359,000,899	$ 77,904,846	$ 149,666,969	$ 9,737	= line 11 * line 19
22	Streetlighting Fixtures	$ 460,055	$ -	$ -	$ -	$ 460,055	= line 12 * line 19
23	Customer Service	$ 88,900,653	$ 77,248,132	$ 7,058,398	$ 4,589,926	$ 4,196	= line 13 * line 19
24	Measurement	$ 122,292,288	$ 81,853,545	$ 29,648,261	$ 10,790,383	$ 100	= line 14 * line 19
25	Total	$ 1,567,568,084	$ 1,146,485,235	$ 201,798,807	$ 218,728,739	$ 555,303	

Inter Class Revenue Allocations

Calculation of Increase Limits

EXHIBIT P-9G
Schedule SS-G8

$ 1,567,568

line #		(in $1,000)		Notes:
1	Requested Revenue Increase to be recovered from rate schedule charges =	$ 422,815		SS-G10
2	Present Distribution Revenue =	$ 1,144,753	from RSG, GSG, LVG & SLG	SS-G8, pg 2, col 3, line 11
3	Present Total Customer Bills (all on BGSS) =	$ 2,629,735		SS-G8, pg 2, col 5, line 11
4	Average Distribution Increase =	36.935%		= Line 1 / Line 2
5	Average Total Bill Increase =	16.078%		= Line 1 / Line 3
6	Lower Distribution increase limit =	18.468%	in Distribution charges	= 0.5 * Line 4
7	Upper Distribution increase limit #1 =	55.403%	in Distribution charges	= 1.5 * Line 4
8	Upper Bill increase limit #2 =	32.156%	in Bill Increase	= 2.0 * Line 5

all rounded to 0.001%

Inter Class Revenue Allocations
Calculation of Increases

EXHIBIT P-9G
Schedule SS-G8
Page 2 of 3

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Requirement (from COS) (in $1,000)	(3) Present Distribution Revenue (in $1,000)	(4) Unlimited COS Distribution Charge $ Increase (in $1,000)	(5) Present Total Bill Revenue (all on BGSS) (in $1,000)	(6) Unlimited Distribution Charge Increase (%)	(7) Change in MAC & BGSS credits (in $1,000)	(8) Limited Final Distribution Charge Increase (%)	(9) Proposed Total Bill Increase (%)	(10) Proposed Distribution Revenue Increase (in $1,000)
	Calculation of TSG-F Increase									
1	TSG-F	$ 8,126.527	$ 3,142	$ 4,984.680	$ 15,959	158.654%	$ (44.479)	55.403%	10.628%	$ 1,741
	Calculation of TSG-NF & CIG Increase									
2	TSG-NF	----	$ 14,306	----	$ 83,840	----		36.935%	6.302%	$ 5,284
3	CIG	----	$ 2,387	----	$ 11,299	----		36.935%	7.806%	$ 882
4	CSG[1]	----	$ 724,974	----	$ 725,553	----		----	0.013%	$ 95
	Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase									
5	RSG	$ 1,146,485	$ 846,314	$ 300,171	$ 1,640,209	35.468%	$ (5,133.00)	35.505%	18.007%	$ 300,484
6	GSG	$ 201,799	$ 129,608	$ 72,191	$ 332,335	55.699%	$ (797.00)	55.403%	21.367%	$ 71,807
7	LVG	$ 218,729	$ 168,359	$ 50,370	$ 655,917	29.918%	$ (2,033.0)	29.949%	7.377%	$ 50,423
8	SLG	$ 555.303	$ 472.129		$ 1,274.599					
9	Distribution Only*	$ 95.248	$ 38.213	$ 57.034		149.251%	$ (2.1390)	55.403%	1.493%	$ 21.171
10	Fixtures*	$ 460.055	$ 433.916	$ 26.139		6.024%		18.468%	6.276%	$ 80.000
11	Total for Margin Rates	$ 1,567,568	$ 1,144,753	$ 422,815	$ 2,629,735	36.935%	$ (7,965)	36.935%	15.775%	$ 422,815

[1] CSG Credits all flow back through BGSS

** SLG rows shaded grey (including Distribution & Fixtures) are shown to 3 decimal points*

Notes:	for TSG-F - from SS-G7, pg 1, col 6, line 6 for RSG, GSG, LVG & SLG from SS-G7 pg 2, line 25	SS-G12	= (2) - (3)	Page 6	= (4) / (3)	SS-G12	calculated on limits	= (Col 10 + Col 7) / Col 5	= (3) * (8)

Inter Class Revenue Allocations
Calculation of Increases

EXHIBIT P-9G
Schedule SS-G8
Page 3 of 3

line #	(1) Rate Schedule	(2) Proposed Distribution Revenue Increase (in $000s)	(3) Proposed Tax Adjustment Credit (in $000s)	(4) Proposed SBC Bad Debts (in $000s)	(5) Proposed SRC (DAC) (in $000s)	(6) Net Delivery Revenue Increase (in $000s)	(7) Net Total Bill Increase (in %)
	Calculation of TSG-F Increase						
1	TSG-F	$ 1,741	$ 359	$ 321	$ 10	$ 2,430	15.2%
	Calculation of TSG-NF & CIG Increase						
2	TSG-NF	$ 5,284	$ 1,032	$ 1,927	$ 62	$ 8,305	9.9%
3	CIG	$ 882	$ 306	$ 383	$ 12	$ 1,584	14.0%
4	CSG	$ 95	$ 599	$ -	$ -	$ 694	0.1%
	Calculation of Margin Rates (RSG, GSG, LVG & SLG) Increase						
5	RSG	$ 300,484	$ (77,037)	$ 23,353	$ 749	$ 247,549	15.1%
6	GSG	$ 71,807	$ (12,593)	$ 4,420	$ 142	$ 63,776	19.2%
7	LVG	$ 50,423	$ (15,330)	$ 11,566	$ 371	$ 47,030	7.2%
8	SLG					$ -	0.0%
9	*Distribution Only**	$ 21.171	$ (49.129)	$ 10.365	$ 0.333	$ (17.261)	-1.4%
10	*Fixtures**	$ 80.000				$ 80.000	6.3%
11	Total for Margin Rates Distribution Only* Fixtures*	$ 422,815	$ (102,712)	$ 41,980	$ 1,347	$ 363,430	13.8%
		Column 10 SS-G8 Page 2	SS-TAC-6G	SS-SBC-3	SS-SRC-3G	Col 6 = Col2+ Col3+ Col4+ Col5	Col7 = Col 6 / Page 2 Col 5

** SLG rows shaded grey (including Distribution & Fixtures) are shown to 3 decimal points*

Service Charge Calculations

EXHIBIT P-9G
Schedule SS-G9

line #	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	Notes:
1			Average Distribution Increase =		36.935%					SS-G8 Page 1, line 4
	Rate Schedule	Distribution Access Rev Req (in $1,000)	Customer Service Rev Req (in $1,000)	Measurement Rev Req (in $1,000)	COS Indicated Total Rev Req (in $1,000)	# of Customers	Cost Based Monthly Service Charge ($/month)	Current Monthly Service Charge ($/month)	Proposed Limited Monthly Service Charge ($/month)	
2	RSG	628,383	77,248	81,854	787,484	1,712,253	$ 38.33	$ 8.08	$ 12.56	move to costs, limited @ 1.5 times overall avg Distribution % increase
3	GSG	87,187	7,058	29,648	123,894	140,296	$ 73.59	$ 18.97	$ 29.48	move to costs, limited @ 1.5 times overall avg Distribution % increase
4	LVG	53,681	4,590	10,790	69,062	19,537	$ 294.58	$ 168.50	$ 261.85	move to costs, limited @ 1.5 times overall avg Distribution % increase
5	TSG-F	429	150	185	764	64	$ 994.97	$ 902.42	$ 994.97	move to costs, limited @ 1.5 times overall avg Distribution % increase
6	TSG-NF					0.235 2.349 150		$ 902.42	$ 994.97	set equal to new TSG-F Service Charge
7	CIG				diff factor	10		$ 199.11	$ 272.65	increase current @ average Distribution % increase
8	CSG							$ 902.42	$ 994.97	set equal to new TSG-F Service Charge
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Notes:	values for RSG, GSG & LVG for Cols 2, 3, & 4 from page 2, lines 16, 19 & 20 values for TSG-F for Cols 2, 3 & 4 from 2023 Rate Case Schedule SS-G7, page 1, lines 1, 4 & 5				= (2) + (3) + (4)	RSG, GSG & LVG from 2023 Rate Case Schedule SS-G7, page 2, line 1 TSG-F from COS workpapers	= Col 5 * 1000 / Col 6 / 12 rounded to $0.01	From Tariff	based on methodology described	

Filing "5 and 7"

COMMODITY BGSS
ACTUAL
"5 and 7" Months Ended May 31, 2024
(Units, $, 000)

EXHIBIT P-9G
Schedule SS-G10

	REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
1	BGSS-RSG	18,127	13,877	12,299	13,731	18,234	48,378	87,217	99,614	100,466	81,913	51,991	27,379	573,225
2	BGSSF-GSG	3,120	2,666	2,729	2,736	3,853	11,475	24,316	29,035	29,427	23,582	13,833	6,464	153,237
3	BGSSF-LVG	3,470	3,124	2,987	2,966	4,570	13,764	27,755	30,856	34,420	28,456	16,905	9,312	178,584
4	BGSSF-SLG	17	11	11	12	12	16	17	15	15	15	14	13	169
5	TSGF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.000
6	Emergency Sales - TSGF	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.103
7	BGSSI-TSGNF	42	88	12	99	143	316	340	312	314	301	280	268	2,514
8	BGSSI-TSGNF - Pilot Use	0	0	0	2	(4)	0	0	0	0	0	0	0	(2.806)
9	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0.0000
10	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0.0000
11	CIG - Supply Component	992	376	181	979	444	757	821	708	687	619	549	543	7,656
12	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0.000
13	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0.000
14	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0.000
15														
16														
17	**THERMS**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
18	BGSS-RSG	41,058	31,489	27,923	31,172	46,401	122,562	220,957	272,092	274,420	223,742	142,012	74,786	1,508,614
19	BGSSF-GSG	6,787	5,608	5,501	5,511	7,371	16,857	33,484	43,198	43,684	36,358	22,750	11,031	238,140
20	BGSSF-LVG	7,375	6,335	5,888	6,010	8,690	20,219	38,220	45,906	51,095	43,873	27,801	15,891	277,304
21	BGSSF-SLG	37	22	22	24	22	23	23	23	23	23	23	23	288
22	TSGF	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Emergency Sales - TSGF	0	0	0	0	0	0	0	0	0	0	0	0	0.205
24	BGSSI-TSGNF	97	186	26	212	289	529	529	529	529	529	529	529	4,509
25	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
26	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
28	CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,167	2,167	2,167	2,167	2,167	2,167	2,167	26,039
29	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
30	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
31	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
32														
33														
34	**AVG $/THERM**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
35	BGSS-RSG	0.441494	0.440687	0.440465	0.440480	0.392964	0.394721	0.218947	0.366104	0.366104	0.366104	0.366104	0.366104	0.379968
36	BGSSF-GSG	0.459648	0.475397	0.495998	0.496471	0.522756	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.643473
37	BGSSF-LVG	0.470539	0.493123	0.507319	0.493556	0.525821	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.644003
38	BGSSF-SLG	0.467343	0.499357	0.503216	0.504393	0.523142	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.585408
39	TSGF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	Emergency Sales - TSGF	0.473821	0.000000	0.000000	0.511911	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.500368
41	BGSSI-TSGNF	0.431487	0.474112	0.462786	0.466892	0.495541	0.598171	0.642712	0.590776	0.593389	0.568835	0.529085	0.507457	0.557574
42	BGSSI-TSGNF - Pilot Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	BGSSI-TSGNF - Penalty Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	Emergency Sales - TSGNF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	CIG - Supply Component	0.261212	0.251871	0.277094	0.281846	0.304848	0.349383	0.379114	0.326764	0.317005	0.285686	0.253610	0.250518	0.294026
46	CSG - BGSS-F	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	CSG - BGSS-I	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	CSG - Emergency Sales	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

	REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
1	BGSS-RSG	21,171	13,880	12,302	13,734	19,525	48,378	87,217	99,614	100,466	81,913	51,991	27,379	577,570
2	BGSSF-GSG	3,161	2,666	2,729	2,736	3,858	11,475	24,316	29,035	29,427	23,582	13,833	6,464	153,283
3	BGSSF-LVG	3,791	3,124	2,987	2,966	4,869	13,764	27,755	30,856	34,420	28,456	16,905	9,312	179,204
4	BGSSF-SLG	17	11	11	12	12	16	17	15	15	15	14	13	169
5	TSGF	0.0000	0.0000	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0
6	Emergency Sales - TSGF	0.0294	0.0000	0.0000	0.0731	0.0000	0	0	0	0	0	0	0	0.103
7	BGSSI-TSGNF	42	88	12	99	143	316	340	312	314	301	280	268	2,514
8	BGSSI-TSGNF - Pilot Use	0	0	0	2	(4)	0	0	0	0	0	0	0	(2.806)
9	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0.00
10	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0.00
11	CIG - Supply Component	992	376	181	979	444	757	821	708	687	619	549	543	7,656
12	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
13	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
14	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
15														
16														
17	**THERMS**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
18	BGSS-RSG	47,953	31,496	27,930	31,180	49,686	122,562	220,957	272,092	274,420	223,742	142,012	74,786	1,518,815
19	BGSSF-GSG	6,876	5,608	5,501	5,511	7,380	16,857	33,484	43,198	43,684	36,358	22,750	11,031	238,239
20	BGSSF-LVG	8,056	6,335	5,888	6,010	9,259	20,219	38,220	45,906	51,095	43,873	27,801	15,891	278,553
21	BGSSF-SLG	37	22	22	24	22	23	23	23	23	23	23	23	288
22	TSGF	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000
23	Emergency Sales - TSGF	0.062	0.000	0.000	0.143	0.000	0	0	0	0	0	0	0	0.205
24	BGSSI-TSGNF	97	186	26	212	289	529	529	529	529	529	529	529	4,509
25	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
26	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
28	CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,167	2,167	2,167	2,167	2,167	2,167	2,167	26,039
29	CSG - BGSS-F	0	0	0	0	0	0	0	0	0	0	0	0	0
30	CSG - BGSS-I	0	0	0	0	0	0	0	0	0	0	0	0	0
31	CSG - Emergency Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
32														
33														
34	**AVG $/THERM**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
35	BGSS-RSG	0.441496	0.440687	0.440465	0.440480	0.392965	0.394721	0.394721	0.366104	0.366104	0.366104	0.366104	0.366104	0.380276
36	BGSSF-GSG	0.459648	0.475397	0.495998	0.496471	0.522756	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.643399
37	BGSSF-LVG	0.470539	0.493123	0.507319	0.493556	0.525821	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.643337
38	BGSSF-SLG	0.467343	0.499357	0.503216	0.504393	0.523142	0.680753	0.726185	0.672150	0.673644	0.648598	0.608054	0.585994	0.585408
39	TSGF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
40	Emergency Sales - TSGF	0.473821	0.000000	0.000000	0.511911	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.500368
41	BGSSI-TSGNF	0.431487	0.474112	0.462786	0.466892	0.495541	0.598171	0.642712	0.590776	0.593389	0.568835	0.529085	0.507457	0.557574
42	BGSSI-TSGNF - Pilot Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
43	BGSSI-TSGNF - Penalty Use	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	Emergency Sales - TSGNF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
45	CIG - Supply Component	0.261212	0.251871	0.277094	0.281846	0.304848	0.349383	0.379114	0.326764	0.317005	0.285686	0.253610	0.250518	0.294026
46	CSG - BGSS-F	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
47	CSG - BGSS-I	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
48	CSG - Emergency Sales	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

	REVENUES	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Total
1	BGSS-RSG	21,624	14,226	12,612	14,071	18,882	46,680	84,272	103,710	104,569	85,401	54,119	28,491	588,657
2	BGSSF-GSG	4,012	3,609	3,431	3,536	4,849	12,082	22,046	38,969	30,791	22,551	13,022	6,536	165,434
3	BGSSF-LVG	13,375	12,606	12,521	13,470	14,833	34,016	50,595	85,443	69,888	53,827	33,934	21,563	416,071
4	BGSSF-SLG	34	29	27	29	30	34	31	43	34	29	27	27	375
5	TSGF @ BGSSF (LVG)	679	737	719	778	688	1,019	1,234	1,844	1,490	1,162	979	776	12,105
6	Emergency Sales - TSGF	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TSGNF @ BGSSI	3,607	3,976	3,451	4,646	4,213	6,375	6,210	8,088	7,733	5,520	5,428	4,391	63,638
8	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
9	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
11	CIG - Supply Component	932	431	181	986	444	750	649	1,097	743	593	490	517	7,813
12	CSG - BGSS-F	19,279	25,384	35,786	59,724	31,142	10,369	54,544	31,227	19,472	24,227	(7,759)	50,666	354,061
13	CSG - BGSS-I	17,757	23,549	33,139	55,365	29,081	9,732	50,928	29,648	18,215	22,420	(7,127)	46,608	329,315
14	CSG - Emergency Sales	19,521	25,690	36,204	60,391	31,314	10,453	54,720	31,693	19,586	24,626	(7,764)	51,286	357,720
15														
16														
17	**THERMS**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
18	BGSS-RSG	48,877	32,156	28,507	31,806	50,650	125,214	226,053	278,194	280,498	229,080	145,168	76,426	1,552,629
19	BGSSF-GSG	8,573	7,062	6,866	6,985	9,137	21,141	41,616	53,310	53,762	45,505	28,705	14,162	296,824
20	BGSSF-LVG	28,578	24,666	25,055	26,607	27,952	59,525	95,510	116,888	122,028	108,614	74,804	46,725	756,952
21	BGSSF-SLG	71.681	56.796	54.164	56.744	56.558	59.300	59.300	59.300	59.300	59.300	59.300	59.300	711.043
22	TSGF @ BGSSF (LVG)	1,452	1,441	1,439	1,537	1,296	1,783	2,329	2,522	2,602	2,344	2,158	1,681	22,583
23	Emergency Sales - TSGF	0	0	0	0	0	0	0	0	0	0	0	0	0
24	TSGNF @ BGSSI	8,369	8,387	7,458	9,900	8,502	11,886	12,555	11,654	14,434	12,036	13,027	10,344	128,549
25	BGSSI-TSGNF - Pilot Use	0	0	0	0	0	0	0	0	0	0	0	0	0
26	BGSSI-TSGNF - Penalty Use	0	0	0	0	0	0	0	0	0	0	0	0	0
27	BGSSI-TSGNF - Less Pilot & P	8,369	8,387	7,458	9,900	8,502	11,886	12,555	11,654	14,434	12,036	13,027	10,344	128,549
28	Emergency Sales - TSGNF	0	0	0	0	0	0	0	0	0	0	0	0	0
29	CIG - Supply Component	3,797	1,493	651	3,475	1,458	2,167	2,167	2,167	2,167	2,167	2,167	2,167	26,039
30	CSG - BGSS-F	41,194	49,669	71,609	117,969	58,686	18,145	102,964	42,719	33,999	48,886	(17,104)	109,787	678,524
31	CSG - BGSS-I	41,194	49,669	71,609	117,969	58,686	18,145	102,964	42,719	33,999	48,886	(17,104)	109,787	678,524
32	CSG - Emergency Sales	41,194	49,669	71,609	117,969	58,686	18,145	102,964	42,719	33,999	48,886	(17,104)	109,787	678,524
33														
34														
35	**AVG $/THERM w/o SUT**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Total**
36	BGSS-RSG	0.442408	0.442408	0.442408	0.442408	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.372799	0.379136
37	BGSS RSG OFF Peak	0.279082	0.279082	0.279082	0.279082	0.279082	-	-	-	-	-	-	0.279082	0.239213
38	BGSSF-GSG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.730985	0.572719	0.495577	0.453638	0.461490	0.557347
39	BGSSF-LVG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.730985	0.572719	0.495577	0.453638	0.461490	0.549666
40	BGSSF-SLG (BGSS-F)	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.730985	0.572719	0.495577	0.453638	0.461490	0.526898
41	TSGF @ BGSSF	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.730985	0.572719	0.495577	0.453638	0.461490	0.536024
42	Emergency Sales - TSGF	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.741888	0.576071	0.503735	0.453918	0.467143	0.000000
43	TSGNF @ BGSSI	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.694020	0.535755	0.458612	0.416673	0.424528	0.495048
44	BGSSI-TSGNF - Pilot Use	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.694020	0.535755	0.458612	0.416673	0.424528	0.000000
45	BGSSI-TSGNF - Penalty Use	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.694020	0.535755	0.458612	0.416673	0.424528	0.000000
46	Emergency Sales - TSGNF	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.741888	0.576071	0.503735	0.453918	0.467143	0.000000
47	CIG - Supply Component	0.245365	0.288423	0.277094	0.283624	0.304848	0.346269	0.299746	0.506398	0.343107	0.273506	0.225980	0.238835	0.300048
48	CSG - BGSS-F	0.468006	0.511067	0.499741	0.506271	0.530652	0.571468	0.529734	0.730985	0.572719	0.495577	0.453638	0.461490	0.521811
49	CSG - BGSS-I	0.431051	0.474112	0.462786	0.469316	0.495541	0.536357	0.494622	0.694020	0.535755	0.458612	0.416673	0.424528	0.485340
50	CSG - Emergency Sales	0.473888	0.517224	0.505582	0.511918	0.533592	0.576082	0.531449	0.741888	0.576071	0.503735	0.453918	0.467143	0.527203
51														
52														

53 BGSS-RSG "Weather Normalized All" - used tariff rates with out SUT (effective 6/1/2023 the rate was $0.442408; and effective as of 10/1/2023 the rate is $0.372799).
54 BGSS-RSG excludes Off-Peak volume because it has its own specific BGSS-RSGOP rate (effective as of 5/1/2023 the rate is $0.279082). Applicable May - October only.
55 BGSS-RSG does not include any BGSS-RSG Bill Credits.
56 GSG includes Off-Peak usage.
57 All BGSS rates (BGSS-Firm, BGSS-Interruptible, BGSS-CIG) are monthly changing rates and are based on the most current Tariff rates applicable for that month.
58 All BGSS rates exclude SUT.

Gas Proof of Revenue by Rate Schedule

Narrative for Rate Schedule Design

The summary and each rate schedule provide the details of 1) a) Actual and b) Weather Normalized and also 2) a) Annualized Weather Normalized (all customers assumed to be on BGSS and revenue based on current tariff rates), b) the Proposed rate design.

1) Actual and Weather Normalized

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Balancing Charge, Societal Benefits Charge, Margin Adjustment Charge, Gas Conservation Incentive Program, Green Programs Recovery Charge, Tax Adjustment Credit, Facilities Charge, Minimum Charge, Miscellaneous items, and Unbilled Revenue. The first column shows the actual billing units for the test year from Schedule SS-G2. The second column shows annual average rates (without Sales and Use Tax, SUT) occurring during the test period. The commodity rates in the second column reflect class-weighted averages for the test year from SS-G11. The third column presents annualized revenue for the test period. The fourth column shows the weather normalized billing units for the test year from SS-G2. The fifth column shows the applicable rates. Column six (6) presents weather normalized revenue. Columns seven (7) and eight (8) show the differential revenue, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

2) Annualized Weather Normalized (all customers assumed to be on BGSS) and the Proposed rate design.

All the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the Schedule are lines for Balancing Charge, Societal Benefits Charge, Margin Adjustment Charge, Gas Conservation Incentive Program, Green Programs Recovery Charge, Tax Adjustment Credit, Facilities Charge, Minimum Charge, Miscellaneous items, and Unbilled Revenue. The first column shows the annualized weather normalized billing units for the test year from Schedule SS-G2. The second column shows present Delivery rates (without Sales and Use Tax, SUT) effective November 1, 2023. The commodity rates in the second column reflect class-weighted averages for the test year from SS-G11. The third column presents annualized revenue for the test period assuming all customers are provided service under their applicable BGSS provision. The fourth column repeats the billing units of the first column. The fifth column shows the proposed rates that result in the proposed revenues shown in column six (6). Columns seven (7) and eight (8) show the proposed revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

	Rate Schedule		Actual		Weather Normalized		Difference	
			Therms	Revenue	Therms	Revenue	Revenue	Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,542,270	$1,509,167	1,552,629	$1,521,695	$12,528	0.83
2	GSG		296,702	312,018	296,824	312,059	41	0.01
3	LVG		752,946	412,567	756,952	414,738	2,171	0.53
6	SLG		711	938	711	938	0	0.00
7		Subtotal	2,592,629	2,234,690	2,607,117	2,249,430	14,740	0.66
8								
9	TSG-F		22,583	3,876	22,583	3,876	0	0.00
10	TSG-NF		128,549	23,297	128,549	23,297	0	0.00
11	CIG		26,039	11,307	26,039	11,307	0	0.00
12	CSG		678,524	725,426	0	725,426	0	0.00
15		Subtotal	855,695	763,905	177,171	763,905	0	0.00
16								
17		Totals	3,448,324	$2,998,595	2,784,288	$3,013,335	$14,740	0.49

Notes: SLG units and revenues shown to 3 decimals.
TSG-F revenues shown to 3 decimals.

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

	Rate Schedule		Annualized Weather Normalized Therms	Annualized Weather Normalized Revenue	Proposed Therms	Proposed Revenue	Difference Revenue	Difference Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,552,629	$1,640,209	1,552,629	$1,938,685	$298,476	18.20
2	GSG		296,824	332,335	296,824	403,942	71,607	21.55
3	LVG		756,952	655,917	756,952	705,832	49,915	7.61
6	SLG		711	1,274.599	711	1,375.059	100.460	7.88
7		Subtotal	2,607,117	2,629,735	2,607,117	3,049,834	420,099	15.97
8								
9	TSG-F		22,583	15,959.350	22,583	17,700.027	1,740.677	10.91
10	TSG-NF		128,549	83,840	128,549	89,124	5,284	6.30
11	CIG		26,039	11,299	26,039	12,181	882	7.81
12	CSG		678,524	725,553	678,524	725,648	95	0.01
13		Subtotal	855,695	836,652	855,695	844,654	8,002	0.96
14								
15		Totals	3,462,812	3,466,387	3,462,812	3,894,488	$428,100	12.35
16								
17								
18					Less change in MAC included above		$5,285	
19								
20					Gas Revenue Requirement		$422,815	
21								
22								

		Increase Before Mac Adjustment	Increase Above	MAC Adjustment
23				
24	RSG	$295,353	$298,476	3,123
25	GSG	71,010	71,607	597
26	LVG	48,390	49,915	1,525
27	SLG	99.032	100.460	1.428
28	Subtotal	414,852	420,099	5,246
29				
30	TSG-F	1,696.198	1,740.677	44.479
31	TSG-NF	5,284	5,284	0
32	CIG	882	882	0
33	CSG	95	95	0
34	Subtotal	7,957	8,002	44
35				
36	Totals	$422,809	$428,100	5,291
37				
38				

39 Notes:
40 All customers assumed to be on BGSS.
41 SLG units and revenues shown to 3 decimals.
42 TSG-F revenues shown to 3 decimals.
43 Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023
44 plus applicable BGSS charges.

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	20,547.031	8.08	$166,021	20,547.031	8.08	$166,021	0	0.00
2	Distribution Charge	1,542,229	0.437563	674,822	1,552,588	0.437548	679,333	4,511	0.67
3	Off-Peak Dist Non Exempt	41	0.369093	15	41	0.369093	15	0	0.00
4	Balancing Charge	1,146,626	0.094394	108,235	1,156,985	0.094387	109,205	970	0.90
5	SBC	1,542,270	0.056329	86,875	1,552,629	0.056247	87,331	457	0.53
6	Margin Adjustment	1,542,270	(0.006399)	(9,869)	1,552,629	(0.006395)	(9,930)	(60)	0.61
7	Weather Normalization	1,146,626	0.000000	0	1,156,985	0.000000	0	0	0.00
8	Green Programs Recovery Charge	1,542,270	0.009011	13,898	1,552,629	0.009008	13,986	89	0.64
9	Tax Adjustment Credit	1,542,270	(0.074688)	(115,189)	1,552,629	(0.074533)	(115,723)	(534)	0.46
10	Gas Conservation Incentive Program	1,542,270	0.009011	13,898	1,552,629	0.009008	13,986	89	0.64
11	Facilities Charges			0			0	0	0.00
12	Minimum			0			0	0	0.00
13	Miscellaneous			0			0	0	0.00
14	Delivery Subtotal	1,542,270		$938,705	1,552,629		$944,224	5,519	0.59
15	Unbilled Delivery			(644)			1,163	1,807	(280.68)
16	Delivery Subtotal w unbilled			$938,061			$945,387	7,326	0.78
17									
18	**Supply**								
19	BGSS-RSG	1,508,614	0.379968	$573,225	1,518,815	0.380276	$577,570	4,345	0.76
20	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
21	Off-Peak Comm. Charge	41	0.383148	16	41	0.383148	16	0	0.00
22									
23	Miscellaneous			0			0	0	0.00
24	Supply subtotal	1,508,614		$573,241	1,518,815		$577,585	4,345	0.76
25	Unbilled Supply			(2,135)			(1,278)	857	(40.15)
26	Supply Subtotal w unbilled			$571,105			$576,307	5,202	0.91
27									
28	Total Delivery + Supply	1,542,270		$1,509,167	1,552,629		$1,521,695	12,528	0.83
29									
30									
31									
32									
33	Notes:								
34	Rates are annual averages derived from actual, excluding SUT.								
35									

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	20,547.031	8.08	$166,020	20,547.031	12.56	$258,000	91,980	55.40
2	Distribution Charge	1,552,588	0.437491	679,243	1,552,588	0.571545	887,374	208,131	30.64
3	Off-Peak Dist	41	0.218746	9	41	0.285773	12	3	33.33
4	Balancing Charge	1,156,985	0.091830	106,246	1,156,985	0.091830	106,246	0	0.00
5	SBC	1,552,629	0.044873	69,671	1,552,629	0.044873	69,671	0	0.00
6	Margin Adjustment	1,552,629	(0.005821)	(9,038)	1,552,629	(0.005821)	(9,038)	0	0.00
7	Weather Normalization	1,156,985	0.000000	0	1,156,985	0.000000	0	0	0.00
8	Green Programs Recovery Charge	1,552,629	0.009026	14,014	1,552,629	0.009026	14,014	0	0.00
9	Tax Adjustment Credit	1,552,629	(0.044386)	(68,915)	1,552,629	(0.044386)	(68,915)	0	0.00
10	Gas Conservation Incentive Program	1,552,629	0.060736	94,300	1,552,629	0.060736	94,300	0	0.00
11	Facilities Charges			0			0	0	0.00
12	Minimum			0			0	0	0.00
13	Miscellaneous			0			0	0	0.00
14	Delivery Subtotal	1,552,629		$1,051,550	1,552,629		$1,351,664	$300,114	28.54
15	Unbilled Delivery			1,295			1,667	372	28.73
16	Delivery Subtotal w unbilled			$1,052,845			$1,353,331	$300,486	28.54
17									
18	**Supply**								
19	BGSS-RSG	1,552,629	0.379136	$588,657	1,552,629	0.379136	$588,657	$0	0.00
20	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
21	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	1,552,629	(0.001297)	(2,014)	(2,014)	0.00
22	Off-Peak Comm. Charge	41	0.239213	10	41	0.239213	10	0	0.00
23									
24	Miscellaneous			0			0	0.00	0.00
25	Supply subtotal	1,552,670		$588,667	1,552,670		$586,653	(2,014.00)	(0.34)
26	Unbilled Supply			(1,303)			(1,299)	4.00	(0.31)
27	Supply Subtotal w unbilled			$587,364			$585,354	(2,010.00)	(0.34)
28									
29	Total Delivery + Supply	1,552,629		$1,640,209	1,552,629		$1,938,685	298,476.00	18.20
30									
31									
32									
33	Notes:								
34	All customers assumed to be on BGSS.								
35	Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023								
36	plus applicable BGSS charges.								
37									

RATE SCHEDULE GSG
GENERAL SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1,683.551	18.97	$31,945	1,683.551	18.97	$31,945	$0	0.00
2	Distribution Charge Pre 7/14/97	1,876	0.328270	616	1,877	0.328269	616	0	0.05
3	Distribution Charge All others	294,815	0.328335	96,798	294,936	0.328334	96,837	40	0.04
4	Off-Peak Dist Charge - Pre 7/14/97	0	0.000000	0	0	0.000000	0	0	0.00
5	Off-Peak Dist Charge - All Others	12	0.164052	2	12	0.164052	2	0	0.00
6	Balancing Charge	210,641	0.094402	19,885	210,763	0.094402	19,896	12	0.06
7	SBC	296,702	0.056386	16,730	296,824	0.056381	16,735	5	0.03
8	Margin Adjustment	296,702	(0.006402)	(1,900)	296,824	(0.006402)	(1,900)	(1)	0.04
9	Weather Normalization	210,641	0.000000	0	210,763	0.000000	0	0	0.00
10	Green Programs Recovery Charge	296,702	0.009010	2,673	296,824	0.009010	2,674	1	0.04
11	Tax Adjustment Credit	296,702	(0.065574)	(19,456)	296,824	(0.065564)	(19,461)	(5)	0.03
12	Gas Conservation Incentive Program	296,702	0.032578	9,666	296,824	0.032576	9,669	4	0.04
13	Facilities Charges			0			0	0	0.00
14	Minimum			0			0	0	0.00
15	Miscellaneous			(9)			(9)	0	0.00
16	Delivery Subtotal	296,702		$156,950	296,824		$157,005	$56	0.04
17	Unbilled Delivery			333			298	(35)	(10.49)
18	Delivery Subtotal w unbilled			$157,283			$157,304	$21	0.01
19									
20	**Supply**								
21	BGSS	238,140	0.643473	$153,237	238,239	0.643399	$153,283	46	0.03
22	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
23									
24	Miscellaneous			0			0	0	0.00
25	Supply subtotal	238,140		$153,237	238,239		$153,283	$46	0.03
26	Unbilled Supply			1,498			1,472	(26)	(1.70)
27	Supply Subtotal w unbilled			$154,735			$154,755	$20	0.01
28									
29	Total Delivery + Supply	296,702		$312,018	296,824		$312,059	$41	0.01
30									
31									
32									
33	Notes:								
34	Rates are annual averages derived from actual, excluding SUT.								
35									

RATE SCHEDULE GSG
GENERAL SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1,683.551	18.97	$31,937	1,683.551	29.48	$49,631	$17,694	55.40
2	Distribution Charge - Pre 7/14/97	1,877	0.328263	616	1,877	0.510112	957	341	55.36
3	Distribution Charge - All Others	294,936	0.328263	96,816	294,936	0.510112	150,450	53,634	55.40
4	Off-Peak Dist Charge - Pre 7/14/97	0	0.164132	0	0	0.255056	0	0	0.00
5	Off-Peak Dist Charge - All Others	12	0.164132	2	12	0.255056	3	1	50.00
6	Balancing Charge	210,763	0.091830	19,354	210,763	0.091830	19,354	0	0.00
7	SBC	296,824	0.044873	13,319	296,824	0.044873	13,319	0	0.00
8	Margin Adjustment	296,824	(0.005821)	(1,728)	296,824	(0.005821)	(1,728)	0	0.00
9	Weather Normalization	210,763	0.000000	0	210,763	0.000000	0	0	0.00
10	Green Programs Recovery Charge	296,824	0.009026	2,679	296,824	0.009026	2,679	0	0.00
11	Tax Adjustment Credit	296,824	(0.037671)	(11,182)	296,824	(0.037671)	(11,182)	0	0.00
12	Gas Conservation Incentive Program	296,824	0.044451	13,194	296,824	0.044451	13,194	0	0.00
13	Facilities Charges			0			0	0	0.00
14	Minimum			0			0	0	0.00
15	Miscellaneous			(9)			(8)	1	(10.98)
16	Delivery Subtotal	296,824		$164,998	296,824		$236,669	$71,671	43.44
17	Unbilled Delivery			314			450	136	43.31
18	Delivery Subtotal w unbilled			$165,312			$237,119	$71,807	43.44
19									
20	**Supply**								
21	BGSS	296,824	0.557347	$165,434	296,824	0.557347	$165,434	$0	0.00
22	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
23	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	296,824	(0.000667)	(198)	(198)	0.00
24									
25	Miscellaneous			0			0	0	0.00
26	Supply subtotal	296,824		$165,434	296,824		$165,236	(198)	(0.12)
27	Unbilled Supply			1,589			1,587	(2)	(0.13)
28	Supply Subtotal w unbilled			$167,023			$166,823	(200)	(0.12)
29									
30	Total Delivery + Supply	296,824		$332,335	296,824		$403,942	$71,607	21.55
31									
32									
33									
34	Notes:								
35	All customers assumed to be on BGSS.								
36	Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023								
37	plus applicable BGSS charges.								
38									

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	234.446	168.49	$39,502	234.446	168.49	$39,502	$0	0.00
2	Demand Charge	21,229	4.3693	92,755	21,229	4.3693	92,755	0	0.00
3	Distribution Charge 0-1,000 pre 7/14/97	8,407	0.034933	294	8,453	0.034924	295	2	0.51
4	Distribution Charge over 1,000 pre 7/14/97	20,922	0.052555	1,100	21,048	0.052540	1,106	6	0.57
5	Distribution Charge 0-1,000 post 7/14/97	128,307	0.034927	4,481	129,007	0.034918	4,505	23	0.52
6	Distribution Charge over 1,000 post 7/14/97	595,310	0.048657	28,966	598,445	0.048655	29,117	151	0.52
7	Balancing Charge	452,320	0.094391	42,695	456,326	0.091837	41,908	(787)	(1.84)
8	SBC	752,946	0.055719	41,953	756,952	0.055658	42,130	177	0.42
9	Margin Adjustment	752,946	(0.006368)	(4,795)	756,952	(0.006365)	(4,818)	(23)	0.49
10	Weather Normalization	452,320	0.000000	0	456,326	0.000000	0	0	0.00
11	Green Programs Recovery Charge	752,946	0.008978	6,760	756,952	0.008971	6,791	31	0.46
12	Tax Adjustment Credit	752,946	(0.029909)	(22,520)	756,952	(0.029865)	(22,606)	(86)	0.38
13	Gas Conservation Incentive Program	752,946	0.004095	3,083	756,952	0.004095	3,100	16	0.53
14	Facilities Charges			0			0	0	0.00
15	Minimum			6			6	0	0.00
16	Miscellaneous			(66)			(66)	0	0.00
17	Delivery Subtotal	752,946		$234,214	756,952		$233,724	($490)	(0.21)
18	Unbilled Delivery			(913)			627	1,540	(168.66)
19	Delivery Subtotal w unbilled			$233,301			$234,351	$1,050	0.45
20									
21									
22	**Supply**								
23	BGSS	277,304	0.644003	$178,584	278,553	0.643337	$179,204	$619	0.35
24	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
25									
26	Miscellaneous			0			0	0	0.00
27	Supply Subtotal	277,304		$178,584	278,553		$179,204	$619	0.35
28	Unbilled Supply			681			1,183	502	73.68
29	Supply Subtotal w unbilled			$179,265			$180,387	$1,121	0.63
30									
31	Total Delivery + Supply	752,946		$412,567	756,952		$414,738	$2,171	0.53
32									
33									
34									
35	Notes:								
36	Rates are annual averages derived from actual, excluding SUT.								
37									

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	234.446	168.50	$39,504	234.446	261.85	$61,391	$21,887	55.40
2	Demand Charge	21,229	4.3754	92,884	21,229	5.3427	113,419	20,535	22.11
3	Distribution Charge 0-1,000 pre 7/14/97	8,453	0.033054	279	8,453	0.148008	1,251	972	348.39
4	Distribution Charge over 1,000 pre 7/14/97	21,048	0.050101	1,055	21,048	0.037292	785	(270)	(25.59)
5	Distribution Charge 0-1,000 post 7/14/97	129,007	0.033054	4,264	129,007	0.148008	19,094	14,830	347.80
6	Distribution Charge over 1,000 post 7/14/97	598,445	0.050101	29,983	598,445	0.037292	22,317	(7,666)	(25.57)
7	Balancing Charge	456,326	0.091830	41,904	456,326	0.091830	41,904	0	0.00
8	SBC	756,952	0.044873	33,967	756,952	0.044873	33,967	0	0.00
9	Margin Adjustment	756,952	(0.005821)	(4,406)	756,952	(0.005821)	(4,406)	0	0.00
10	Weather Normalization	456,326	0.000000	0	456,326	0.000000	0	0	0.00
11	Green Programs Recovery Charge	756,952	0.009026	6,832	756,952	0.009026	6,832	0	0.00
12	Tax Adjustment Credit	756,952	(0.017617)	(13,335)	756,952	(0.017617)	(13,335)	0	0.00
13	Gas Conservation Incentive Program	756,952	0.004748	$3,594	756,952	0.004748	$3,594	0	0.00
14	Facilities Charges			0			0	0	0.00
15	Minimum			6			6	0	0.00
16	Miscellaneous			(66)			(66)	0	(0.35)
17	Delivery Subtotal	756,952		$236,465	756,952		$286,753	$50,288	21.27
18	Unbilled Delivery			634			769	135	21.29
19	Delivery Subtotal w unbilled			$237,099			$287,522	$50,423	21.27
20									
21									
22	**Supply**								
23	BGSS	756,952	0.549666	$416,071	756,952	0.549666	$416,071	$0	0.00
24	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
25	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	756,952	(0.000667)	(505)	(505)	0.00
26									
27	Miscellaneous			0			0	0	0.00
28	Supply Subtotal	756,952		$416,071	756,952		$415,566	($505)	(0.12)
29	Unbilled Supply			2,747			2,744	(3)	(0.11)
30	Supply Subtotal w unbilled			$418,818			$418,310	($508)	(0.12)
31									
32	Total Delivery + Supply	756,952		$655,917	756,952		$705,832	$49,915	7.61
33									
34									
35									
36	Notes:								
37	All customers assumed to be on BGSS.								
38	Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023								
39	plus applicable BGSS charges.								
40									

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	11.788	13.2351	$156.020	11.788	13.2351	$156.020	$0.000	0.00
2	Double Inverted	0.107	13.2351	1.410	0.107	13.2351	1.410	0.000	0.00
3	Double Upright	0.634	13.2351	8.392	0.634	13.2351	8.392	0.000	0.00
4	Triple prior to 1/1/93	18.078	13.2351	239.263	18.078	13.2351	239.263	0.000	0.00
5	Triple on and after 1/1/93	0.427	67.4762	28.831	0.427	67.4762	28.831	0.000	0.00
6	Distribution Therm Charge	711.043	0.053493	38.036	711.043	0.053500	38.036	0.000	0.00
7	SBC	711.043	0.051877	36.887	711.043	0.051877	36.887	0.000	0.00
8	Margin Adjustment	711.043	(0.006188)	(4.400)	711.043	(0.006188)	(4.400)	0.000	0.00
9	Green Programs Recovery Charge	711.043	0.008950	6.364	711.043	0.008950	6.364	0.000	0.00
10	Tax Adjustment Credit	711.043	(0.109908)	(78.150)	711.043	(0.109908)	(78.150)	0.000	0.00
11	Gas Conservation Incentive Program	711.043	0.000000	0.000	711.043	0.000000	0.000	0.000	0.00
12	Facilities Charges			0.000			0.000	0.000	0.00
13	Minimum			0.000			0.000	0.000	0.00
14	Miscellaneous			0.150			0.150	0.000	0.00
15	Delivery Subtotal	711.043		$432.803	711.043		$432.803	$0.000	0.00
16	Unbilled Delivery			0.000			0.000	0.000	0.00
17	Delivery Subtotal w unbilled			$432.803			$432.803	$0.000	0.00
18									
19	**Supply**								
20	BGSS	287.870	0.585408	$168.521	287.870	0.585408	$168.521	$0.000	0.00
21	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
22	Miscellaneous			168.521			168.521	0.000	0.00
23	Supply Subtotal	287.870		$337.042	287.870		$337.042	$0.000	0.00
24	Unbilled Supply			168.521			168.521	0.000	0.00
25	Supply Subtotal w unbilled			$505.563			$505.563	$0.000	0.00
26									
27	Total Delivery + Supply	711.043		$938.366	711.043		$938.366	$0.000	0.00
28									
29									
30									

31 Notes:
32 SLG units and revenues shown to 3 decimals.
33 Rates are annual averages derived from actual, excluding SUT.

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	11.788	13.2351	$156.020	11.788	15.6794	$184.834	$28.814	18.47
2	Double Inverted	0.107	13.2351	1.410	0.107	15.6794	1.670	0.260	18.44
3	Double Upright	0.634	13.2351	8.392	0.634	15.6794	9.941	1.549	18.46
4	Triple prior to 1/1/93	18.078	13.2351	239.263	18.078	15.6794	283.450	44.187	18.47
5	Triple on and after 1/1/93	0.427	67.4762	28.831	0.427	79.9377	34.156	5.325	18.47
6	Distribution Therm Charge	711.043	0.053531	38.063	711.043	0.083189	59.151	21.088	55.40
7	SBC	711.043	0.044873	31.907	711.043	0.044873	31.907	0.000	0.00
8	Margin Adjustment	711.043	(0.005821)	(4.139)	711.043	(0.005821)	(4.139)	0.000	0.00
9	Green Programs Recovery Charge	711.043	0.009026	6.418	711.043	0.009026	6.418	0.000	0.00
10	Tax Adjustment Credit	711.043	(0.065353)	(46.469)	711.043	(0.065353)	(46.469)	0.000	0.00
11	Gas Conservation Incentive Program	711.043	0.000000	0.000	711.043	0.000000	0.000	0.000	0.00
12	Facilities Charges			0.000			0.000	0.000	0.00
13	Minimum			0.000			0.000	0.000	0.00
14	Miscellaneous			0.150			0.098	(0.052)	(34.56)
15	Delivery Subtotal	711.043		$459.846	711.043		$561.017	$101.171	22.00
16	Unbilled Delivery			0.000			0.000	0.000	0.00
17	Delivery Subtotal w unbilled			$459.846			$561.017	$101.171	22.00
18									
19	**Supply**								
20	BGSS	711.043	0.526898	$374.647	711.043	0.526898	$374.647	$0.000	0.00
21	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
22	BGSS Contrib. from TSG-F, TSG-NF & CIG	0.000	0.000000	0.000	711.043	(0.000667)	(0.474)	(0.474)	0.00
23	Miscellaneous			168.521			168.521	0.000	0.00
24	Supply Subtotal	711.043		$543.168	711.043		$542.694	($0.474)	(0.09)
25	Unbilled Supply			271.584			271.347	(0.237)	(0.09)
26	Supply Subtotal w unbilled			$814.752			$814.041	($0.711)	(0.09)
27									
28	Total Delivery + Supply	711.043		$1,274.599	711.043		$1,375.059	$100.460	7.88
29									
30									
31									

32 Notes:
33 All customers assumed to be on BGSS.
34 SLG units and revenues shown to 3 decimals.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023
36 plus applicable BGSS charges.

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.129	200.69	$26	0.129	200.69	$26	$0	0.00
2	Margin 0-600,000	24,028	0.094780	2,277	24,028	0.094780	2,277	0	0.00
3	Margin over 600,000	2,011	0.092963	187	2,011	0.092963	187	0	0.00
4	Extended Gas Service	0	0.000000	0	0	0.000000	0	0	0.00
5	SBC	26,039	0.051775	1,348	26,039	0.051775	1,348	0	0.00
6	Green Programs Recovery Charge	26,039	0.008912	232	26,039	0.008912	232	0	0.00
7	Tax Adjustment Credit	26,039	(0.018845)	(491)	26,039	(0.018845)	(491)	0	0.00
8	Gas Conservation Incentive Program	26,039	0.000000	0	26,039	0.000000	0	0	0.00
9	Facilities Charges			0			0	0	0.00
10	Minimum			0			0	0	0.00
11	Miscellaneous			0			0	0	0.00
12	Delivery Subtotal	26,039		$3,580	26,039		$3,580	$0	0.00
13	Unbilled Delivery			98			98	0	0.00
14	Delivery Subtotal w unbilled			$3,678			$3,678	$0	0.00
15									
16	**Supply**								
17	Commodity Component	26,039	0.294026	$7,656	26,039	0.294026	$7,656	$0	0.00
18	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
19	Penalty Use	0		0	0		0	0	0.00
20	Extended Gas Service	866	0.000000	0	0	0.000000	0	0	0.00
21	Miscellaneous			0			0	0	0.00
22	Supply Subtotal	26,905		$7,656	26,039		$7,656	$0	0.00
23	Unbilled Supply			(28)			(28)	0	0.00
24	Supply Subtotal w unbilled			$7,629			$7,629	$0	0.00
25									
26	Total Delivery + Supply	26,039		$11,307	26,039		$11,307	$0	0.00
27									
28									
29									
30	Notes:								
31	Rates are annual averages derived from actual, excluding SUT.								
32									

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.129	199.11	$26	0.129	272.65	$35	$9	34.62
2	Margin 0-600,000	24,028	0.088960	2,138	24,028	0.121590	2,922	784	36.67
3	Margin over 600,000	2,011	0.078960	159	2,011	0.111590	224	65	40.88
4	Extended Gas Service	0	0.150000	0	0	0.150000	0	0	0.00
5	SBC	26,039	0.044873	1,168	26,039	0.044873	1,168	0	0.00
6	Green Programs Recovery Charge	26,039	0.009026	235	26,039	0.009026	235	0	0.00
7	Tax Adjustment Credit	26,039	(0.011756)	(306)	26,039	(0.011756)	(306)	0	0.00
8	Gas Conservation Incentive Program	26,039	0.000000	0	26,039	0.000000	0	0	0.00
9	Facilities Charges			0			0	0	0.00
10	Minimum			0			0	0	0.00
11	Miscellaneous			0			0	0	0.00
12	Delivery Subtotal	26,039		$3,420	26,039		$4,278	$858	25.09
13	Unbilled Delivery			94			118	24	25.53
14	Delivery Subtotal w unbilled			$3,514			$4,396	$882	25.10
15									
16	**Supply**								
17	Commodity Component	26,039	0.300048	$7,813	26,039	0.300048	$7,813	$0	0.00
18	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
19	Penalty Use	0		0	0		0	0	0.00
20	Extended Gas Service	0		0	0		0	0	0.00
21	Miscellaneous			0			0	0	0.00
22	Supply Subtotal	26,039		$7,813	26,039		$7,813	$0	0.00
23	Unbilled Supply			(28)			(28)	0	0.00
24	Supply Subtotal w unbilled			$7,785			$7,785	$0	0.00
25									
26	Total Delivery + Supply	26,039		$11,299	26,039		$12,181	$882	7.81
27									
28									
29									
30	Notes:								
31	All customers assumed to be on BGSS.								
32	Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023								
33	plus applicable BGSS charges.								
34									

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.366	903.42	$330.598	0.366	903.42	$330.598	$0.000	0.00
2	Demand Charge	451	2.1899	988.625	451	2.1899	988.625	0.000	0.00
3	Demand Charge, Agreements	0	0.0000	0.000	0	0.0000	0.000	0.000	0.00
4	Distribution Charge	22,583	0.083830	1,893.135	22,583	0.083830	1,893.135	0.000	0.00
5	Distribution Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
6	SBC	22,583	0.053452	1,207.107	22,583	0.053452	1,207.107	0.000	0.00
7	SBC, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
8	Margin Adjustment	22,583	(0.006261)	(141.397)	22,583	(0.006261)	(141.397)	0.000	0.00
9	Margin Adjustment, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
10	Green Programs Recovery Charge	22,583	0.009016	203.598	22,583	0.009016	203.598	0.000	0.00
11	Green Programs Recovery Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
12	Tax Adjustment Credit	22,583	(0.023218)	(524.326)	22,583	(0.023218)	(524.326)	0.000	0.00
13	Gas Conservation Incentive Program	22,583	0.000000	0.000	22,583	0.000000	0.000	0.000	0.00
14	Facilities Charges			0.000			0.000	0.000	0.00
15	Minimum			0.000			0.000	0.000	0.00
16	Miscellaneous			(4.098)			(4.098)	0.000	0.00
17	Delivery Subtotal	22,583		3,953.243	22,583		3,953.243	0.000	0.00
18	Unbilled Delivery			(77.568)			(77.568)	0.000	0.00
19	Delivery Subtotal w unbilled			3,875.67			3,875.67	0.000	0.00
20									
21	**Supply**								
22	Commodity Charge, BGSS	0	0.000000	$0.000	0	0.000000	$0.000	$0.000	0.00
23	Emergency Sales Service	0	0.500368	0.103	0	0.500368	0.103	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply Subtotal	0		$0.103	0		$0.103	$0.000	0.00
26	Unbilled Supply			0.000			0.000	0.000	0.00
27	Supply Subtotal w unbilled			$0.103			$0.103	$0.000	0.00
28									
29	Total Delivery + Supply	22,583		$3,875.777	22,583		$3,875.777	$0.000	0.00
30									

31 Notes:
32 TSG-F revenues shown to 3 decimals.
33 Rates are annual averages derived from actual, excluding SUT.

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.366	902.42	$330.232	0.366	994.97	$364.100	$33.868	10.26
2	Demand Charge	451	2.1896	988.490	451	3.5144	1,586.567	598.077	60.50
3	Demand Charge, Agreements	0	0.0000	0.000	0	0.0000	0.000	0.000	0.00
4	Distribution Charge	22,583	0.083696	1,890.102	22,583	0.134335	3,033.680	1,143.578	60.50
5	Distribution Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
6	SBC	22,583	0.044873	1,013.365	22,583	0.044873	1,013.365	0.000	0.00
7	SBC, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
8	Margin Adjustment	22,583	(0.005821)	(131.455)	22,583	(0.005821)	(131.455)	0.000	0.00
9	Margin Adjustment, Agreements	0	(0.005821)	0.000	0	(0.005821)	0.000	0.000	0.00
10	Green Programs Recovery Charge	22,583	0.009026	203.834	22,583	0.009026	203.834	0.000	0.00
11	Green Programs Recovery Charge, Agreements	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
12	Tax Adjustment Credit	22,583	(0.015896)	(358.979)	22,583	(0.015896)	(358.979)	0.000	0.00
13	Gas Conservation Incentive Program	22,583	0.000000	0.000	22,583	0.000000	0.000	0.000	0.00
14	Facilities Charges			0.000			0.000	0.000	0.00
15	Minimum			0.000			0.000	0.000	0.00
16	Miscellaneous			(4.098)			(4.106)	(0.008)	0.20
17	Delivery Subtotal	22,583		3,931.491	22,583		5,707.006	1,775.515	45.16
18	Unbilled Delivery			(77.141)			(111.979)	(34.838)	45.16
19	Delivery Subtotal w unbilled			3,854.350			5,595.027	1,740.677	45.16
20									
21	**Supply**								
22	Commodity Charge, BGSS-F	22,583	0.536024	$12,105.000	22,583	0.536024	$12,105.000	$0.000	0.00
23	Emergency Sales Service	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
24	Miscellaneous			0.000			0.000	0.000	0.00
25	Supply Subtotal	22,583		$12,105.000	22,583		$12,105.000	$0.000	0.00
26	Unbilled Supply			0.000			0.000	0.000	0.00
27	Supply Subtotal w unbilled			$12,105.000			$12,105.000	$0.000	0.00
28									
29	Total Delivery + Supply	22,583		$15,959.350	22,583		$17,700.027	$1,740.677	10.91
30									
31									
32									
33	Notes:								
34	All customers assumed to be on BGSS.								
35	TSG-F revenues shown to 3 decimals.								
36	Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023								
37	plus applicable BGSS charges.								

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1.838	901.86	$1,657	1.838	901.86	$1,657	$0	0.00
2	Dist Charge 0-50,000	55,730	0.098952	5,515	55,730	0.098952	5,515	0	0.00
3	Dist Charge 0-50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
4	Dist Charge over 50,000	72,819	0.099027	7,211	72,819	0.099027	7,211	0	0.00
5	Dist Charge over 50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
6	SBC	128,549	0.052028	6,688	128,549	0.052028	6,688	0	0.00
7	SBC, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
8	Green Programs Recovery Charge	128,549	0.008806	1,132	128,549	0.008806	1,132	0	0.00
9	Green Programs Recovery Charge, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
10	Tax Adjustment Credit	128,549	(0.010746)	(1,381)	128,549	(0.010746)	(1,381)	0	0.00
11	Gas Conservation Incentive Program	128,549	0.000000	0	128,549	0.000000	0	0	0.00
12	Facilities Charges			2			2	0	0.00
13	Minimum			0			0	0	0.00
14	Miscellaneous			(38)			(38)	0	0.00
15	Delivery Subtotal	128,549		$20,785	128,549		$20,785	$0	0.00
16	Unbilled Delivery			0			0	0	0.00
17	Delivery Subtotal w unbilled			$20,785			$20,785	$0	0.00
18									
19	**Supply**								
20	Commodity Charge, BGSS-I	4,509	0.557574	$2,514	4,509	0.557574	$2,514	$0	0.00
21	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
22	Pilot Use	0	0.000000	(3)	0	0.000000	(3)	0	0.00
23	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
24	Miscellaneous			0			0	0	0.00
25	Supply Subtotal	4,509		$2,511	4,509		$2,511	$0	0.00
26	Unbilled Supply			0			0	0	0.00
27	Supply Subtotal w unbilled			$2,511			$2,511	$0	0.00
28									
29	Total Delivery + Supply	128,549		$23,297	128,549		$23,297	$0	0.00
30									
31									
32									
33	Notes:								
34	Rates are annual averages derived from actual, excluding SUT.								

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	1.838	902.42	$1,658	1.838	994.97	$1,829	$171	10.31
2	Dist Charge 0-50,000	55,730	0.098680	5,499	55,730	0.138453	7,716	2,217	40.32
3	Dist Charge 0-50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
4	Dist Charge over 50,000	72,819	0.098680	7,186	72,819	0.138453	10,082	2,896	40.30
5	Dist Charge over 50,000, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
6	SBC	128,549	0.044873	5,768	128,549	0.044873	5,768	0	0.00
7	SBC, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
8	Green Programs Recovery Charge	128,549	0.009026	1,160	128,549	0.009026	1,160	0	0.00
9	Green Programs Recovery Charge, Agreements	0	0.000000	0	0	0.000000	0	0	0.00
10	Tax Adjustment Credit	128,549	(0.008031)	(1,032)	128,549	(0.008031)	(1,032)	0	0.00
11	Gas Conservation Incentive Program	128,549	0.000000	0	128,549	0.000000	0	0	0.00
12	Facilities Charges			2			2	0	0.00
13	Minimum			0			0	0	0.00
14	Miscellaneous			(38)			(38)	0	0.00
15	Delivery Subtotal	128,549		$20,202	128,549		$25,486	$5,284	26.16
16	Unbilled Delivery			0			0	0	0.00
17	Delivery Subtotal w unbilled			$20,202			$25,486	$5,284	26.16
18									
19	**Supply**								
20	Commodity Charge, BGSS-I	128,549	0.495048	$63,638	128,549	0.495048	$63,638	$0	0.00
21	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
22	Pilot Use	0	1.890000	0	0	1.890000	0	0	0.00
23	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
24	Miscellaneous			0			0	0	0.00
25	Supply Subtotal	128,549		$63,638	128,549		$63,638	$0	0.00
26	Unbilled Supply			0			0	0	0.00
27	Supply Subtotal w unbilled			$63,638			$63,638	$0	0.00
28									
29	Total Delivery + Supply	128,549		$83,840	128,549		$89,124	$5,284	6.30
30									
31									
32									

33 Notes:
34 All customers assumed to be on BGSS.
35 Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023
36 plus applicable BGSS charges.

RATE SCHEDULE CSG
CONTRACT SERVICES
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Actual			Weather Normalized			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge - Power	0.0000	0.00	$0	0.0000	0.00	$0	$0	0.00
2	Service Charge - Power- Non Firm	0.0000	0.00	0	0.0000	0.00	0	0	0.00
3	Service Charge - Other	0.2302	902.42	208	0.2302	902.42	208	0	0.00
4	Distribution Charge - Power	0	0.000000	0	0	0.000000	0	0	0.00
5	Distribution Charge - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
6	Distribution Charge - Other	678,524	0.008423	5,715	678,524	0.008423	5,715	0	0.00
7	Maintenance - Power	0	0.000000	0	0	0.000000	0	0	0.00
8	Maintenance - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
9	Maintenance - Other	678,524	0.000152	103	678,524	0.000152	103	0	0.00
10	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
11	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
12	Balancing Charge (applicable only if customer uses BGSS-F)	0	0.000000	0	0	0.000000	0	0	0.00
13	SBC	678,524	0.001400	950	678,524	0.001400	950	0	0.00
14	Green Programs Recovery Charge	678,524	0.000335	228	678,524	0.000335	228	0	0.00
15	Tax Adjustment Credit	678,524	(0.001069)	(726)	678,524	(0.001069)	(726)	0	0.00
16	Gas Conservation Incentive Program	678,524	0.000000	0	678,524	0.000000	0	0	0.00
17	Facilities Chg.			464,798			464,798	0	0.00
18	Minimum			253,627			253,627	0	0.00
19	Sales Tax Discount - Delivery			0			0	0	0.00
20	Misc.			0			0	0	0.00
21	Delivery Subtotal	678,524		724,903	678,524		724,903	0	0.00
22	Unbilled Delivery			524			524	0	0.00
23	Delivery Subtotal w/ Unbilled	678,524		725,426	678,524		725,426	0	0.00
24									
25	**Supply:**								
26	BGSS-Firm - Power	0	0.000000	0	0	0.000000	0	0	0.00
27	BGSS-Firm - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
28	BGSS-Firm - Other	0	0.000000	0	0	0.000000	0	0	0.00
29									
30	BGSS-Interruptible - Power	0	0.000000	0	0	0.000000	0	0	0.00
31	BGSS-Interruptible - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
32	BGSS-Interruptible - Other	0	0.000000	0	0	0.000000	0	0	0.00
33									
34	Emergency Sales Svc. - Power	0	0.000000	0	0	0.000000	0	0	0.00
35	Emergency Sales Svc. - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
36	Emergency Sales Svc - Other	0	0.000000	0	0	0.000000	0	0	0.00
37									
38	Pilot Use	0	0.00	0	0	0.000000	0	0	0.00
39	Penalty Use	0	0.000000	0	0	0.000000	0	(0)	(100.00)
40	Misc.			0			0	(0)	(100.00)
41	Supply Subtotal	0		0	0		0	(0)	(100.00)
42	Unbilled Supply			0			0	(0)	(100.00)
43	Supply Subtotal w/ Unbilled	0		0	0		0	(0)	(100.00)
44									
45	**Total Delivery & Supply**			725,426			725,426	0	0.00
46									
47	Notes:								
48	Rates are annual averages derived from actual, excluding SUT.								

RATE SCHEDULE CSG
CONTRACT SERVICES
"5 and 7" Months Ended May 31, 2024
(Therms & Revenue - Thousands, Rate - $/Therm)

		Annualized Weather Normalized			Proposed			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge - Power	0.0000	902.42	$0	0.0000	994.97	$0	$0	0.00
2	Service Charge - Power- Non Firm	0.0000	902.42	0	0.0000	994.97	0	0	0.00
3	Service Charge - Other	0.2302	902.42	208	0.2302	994.97	229	21	10.10
4	Distribution Charge Change (previously Power)	0	0.000000	0	74	1.000000	74	74	0.00
5	Distribution Charge - Power- Non Firm	0	0.098680	0	0	0.138453	0	0	0.00
6	Distribution Charge - Other	678,524	0.008423	5,715	678,524	0.008423	5,715	0	0.00
7	Maintenance - Power	0	0.000000	0	0	0.000000	0	0	0.00
8	Maintenance - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
9	Maintenance - Other	678,524	0.000152	103	678,524	0.000152	103	0	0.00
10	Pilot Use	0	0.000000	0	0	0.000000	0	0	0.00
11	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
12	Balancing Charge (applicable only if customer uses BGSS-F)	0	0.000000	0	0	0.000000	0	0	0.00
13	SBC	678,524	0.044873	950	678,524	0.044873	950	0	0.00
14	Green Programs Recovery Charge	678,524	0.009026	228	678,524	0.009026	228	0	0.00
15	Tax Adjustment Credit	678,524	(0.000883)	(599)	678,524	(0.000883)	(599)	0	0.00
16	Gas Conservation Incentive Program	678,524	0.000000	0	678,524	0.000000	0	0	0.00
17	Facilities Chg.			464,798			464,798	0	0.00
18	Minimum			253,627			253,627	0	0.00
19	Sales Tax Discount - Delivery			0			0	0	0.00
20	Misc.			0			0	0	0.00
21	Delivery Subtotal	678,524		725,029	678,524		725,124	95	0.01
22	Unbilled Delivery			524			524	0	0.00
23	Delivery Subtotal w/ Unbilled	678,524		725,553	678,524		725,648	95	0.01
25	**Supply**								
26	BGSS-Firm - Power	0	0.000000	0	0	0.000000	0	0	0.00
27	BGSS-Firm - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
28	BGSS-Firm - Other	0	0.000000	0	0	0.000000	0	0	0.00
30	BGSS-Interruptible - Power	0	0.000000	0	0	0.000000	0	0	0.00
31	BGSS-Interruptible - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
32	BGSS-Interruptible - Other	0	0.000000	0	0	0.000000	0	0	0.00
34	Emergency Sales Svc. - Power	0	0.000000	0	0	0.000000	0	0	0.00
35	Emergency Sales Svc. - Power- Non Firm	0	0.000000	0	0	0.000000	0	0	0.00
36	Emergency Sales Svc - Other	0	0.000000	0	0	0.000000	0	0	0.00
38	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
39	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
40	Misc.	0		0	0		0	0	0.00
41	Supply Subtotal	0		0	0		0.000	0	0.00
42	Unbilled Supply	0		0	0		0	0	0.00
43	Supply Subtotal w/ Unbilled	0		0	0		0.000	0	0.00
45	**Total Delivery & Supply**	678,524		725,553	678,524		725,648	95.00	0.01

47 Notes:
48 All customers assumed to be on BGSS.
49 Annualized Weather Normalized Revenue reflects Delivery rates as of 11/1/2023
50 plus applicable BGSS charges.

Rate Schedule	Description	Current Total Distribution Charges		Proposed Total Distribution Charges	
		Charge without SUT	Charge Including SUT	Charge without SUT	Charge Including SUT
RSG	Service Charge	$8.08	$8.62	$12.56	$13.39
	Distribution Charges	$0.437491	$0.466475	$0.571545	$0.609410
	Balancing Charge	$0.091830	$0.097914	$0.091830	$0.097914
	Off-Peak Use	$0.218746	$0.233238	$0.285773	$0.304705
GSG	Service Charge	$18.97	$20.23	$29.48	$31.43
	Distribution Charge - Pre July 14, 1997	$0.328263	$0.350010	$0.510112	$0.543907
	Distribution Charge - All Others	$0.328263	$0.350010	$0.510112	$0.543907
	Balancing Charge	$0.091830	$0.097914	$0.091830	$0.097914
	Off-Peak Use Dist Charge - Pre July 14, 1997	$0.164132	$0.175006	$0.255056	$0.271953
	Off-Peak Use Dist Charge - All Others	$0.164132	$0.175006	$0.255056	$0.271953
LVG	Service Charge	$168.50	$179.66	$261.85	$279.20
	Demand Charge	$4.3754	$4.6653	$5.3427	$5.6967
	Distribution Charge 0-1,000 pre July 14, 1997	$0.033054	$0.035244	$0.148008	$0.157814
	Distribution Charge over 1,000 pre July 14, 1997	$0.050101	$0.053420	$0.037292	$0.039763
	Distribution Charge 0-1,000 post July 14, 1997	$0.033054	$0.035244	$0.148008	$0.157814
	Distribution Charge over 1,000 post July 14, 1997	$0.050101	$0.053420	$0.037292	$0.039763
	Balancing Charge	$0.091830	0.097914	$0.091830	$0.097914
SLG	Single-Mantle Lamp	$13.2351	$14.1119	$15.6794	$16.7182
	Double-Mantle Lamp, inverted	$13.2351	$14.1119	$15.6794	$16.7182
	Double Mantle Lamp, upright	$13.2351	$14.1119	$15.6794	$16.7182
	Triple-Mantle Lamp, prior to January 1, 19933	$13.2351	$14.1119	$15.6794	$16.7182
	Triple-Mantle Lamp, on and after January 1, 1993	$67.4762	$71.9465	$79.9377	$85.2336
	Distribution Therm Charge	$0.053531	$0.057077	$0.083189	$0.088700

Gas Tariff Rates
"5 and 7" Months Ended May 31, 2024

EXHIBIT P-9G
Schedule SS-G11
Page 21 of 21

Proposed Revenue Requirement Increase

Rate Schedule	Description	Current Total Distribution Charges		Proposed Total Distribution Charges	
		Charge without SUT	Charge Including SUT	Charge without SUT	Charge Including SUT
TSG-F	Service Charge	$902.42	$962.21	$994.97	$1,060.89
	Demand Charge	$2.1896	$2.3347	$3.5144	$3.7472
	Distribution Charges	$0.083696	$0.089241	$0.134335	$0.143235
TSG-NF	Service Charge	$902.42	$962.21	$994.97	$1,060.89
	Distribution Charge 0-50,000	$0.098680	$0.105218	$0.138453	$0.147626
	Distribution Charge over 50,000	$0.098680	$0.105218	$0.138453	$0.147626
	Special Provision (d)	$1.89	$2.02	$1.89	$2.02
CIG	Service Charge	$199.11	$212.30	$272.65	$290.71
	Distribution Charge 0-600,000	$0.088960	$0.094854	$0.121590	$0.129645
	Distribution Charge over 600,000	$0.078960	$0.084191	$0.111590	$0.118983
	Special Provision (c) 1st para	$1.89	$2.02	$1.89	$2.02
BGSS RSG	Commodity Charge including Losses	$0.372799	$0.397497	$0.371476	$0.396086
CSG	Service Charge	$902.42	$962.21	$994.97	$1,060.89
	Distribution Charge - Non-Firm	$0.098680	$0.105218	$0.138453	$0.147626

COMPARISON OF TYPICAL BILLS
Rate Schedule RSG
Distribution Only

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge	12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage	907	109	347	518	646	760	875	1,004	1,159	1,386	2,151
3	Balancing Therms	675	34	176	303	401	483	568	659	770	930	1,289
4												
5												
6	**Total**	**907**	**109**	**347**	**518**	**646**	**760**	**875**	**1,004**	**1,159**	**1,386**	**2,151**
7												
8	Average Therm Use	76	9	29	43	54	63	73	84	97	115	179
9												
10												
11	**Present Bill**											
12	Total Delivery	$657.29	$165.55	$307.47	$411.56	$490.42	$559.47	$629.63	$707.94	$802.46	$939.97	$1,387.13
13	Total Supply	360.33	43.50	138.04	205.73	256.88	301.97	347.67	398.90	460.69	550.74	855.06
14		$1,017.62	$209.05	$445.51	$617.29	$747.30	$861.44	$977.30	$1,106.84	$1,263.15	$1,490.71	$2,242.19
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$844.16	$238.49	$414.41	$542.84	$640.09	$725.35	$811.95	$908.68	$1,025.41	$1,195.31	$1,751.91
20	Total Supply	359.05	43.34	137.55	205.00	255.96	300.90	346.44	397.49	459.06	548.79	852.03
21	Totals	$1,203.21	$281.83	$551.96	$747.84	$896.05	$1,026.25	$1,158.39	$1,306.17	$1,484.47	$1,744.10	$2,603.94
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$186.87	$72.94	$106.94	$131.28	$149.67	$165.88	$182.32	$200.74	$222.95	$255.34	$364.78
27	Supply	(1.28)	(0.16)	(0.49)	(0.73)	(0.92)	(1.07)	(1.23)	(1.41)	(1.63)	(1.95)	(3.03)
28	Totals	$185.59	$72.78	$106.45	$130.55	$148.75	$164.81	$181.09	$199.33	$221.32	$253.39	$361.75
29												
30												
31												
32	**Increase Percent**											
33	Delivery	28.4	44.1	34.8	31.9	30.5	29.6	29.0	28.4	27.8	27.2	26.3
34	Supply	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
35	Totals	18.2	34.8	23.9	21.1	19.9	19.1	18.5	18.0	17.5	17.0	16.1
36												
37												
38												
39	Notes:	Bills include SUT										
40		Each band represents a decile of customers segmented by annual therm usage.										
		Assumes approval of 2023 TAC filing in current rates										

COMPARISON OF TYPICAL BILLS
Rate Schedule RSG
Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

			Annual Usages									
	Units	Class Avg	Band 1	Band 2	Band 3	Band 4	Band 5	Band 6	Band 7	Band 8	Band 9	Band 10
1	Service Charge	12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage	907	109	347	518	646	760	875	1,004	1,159	1,386	2,151
3	Balancing Therms	675	34	176	303	401	483	568	659	770	930	1,289
4												
5												
6	**Total**	**907**	**109**	**347**	**518**	**646**	**760**	**875**	**1,004**	**1,159**	**1,386**	**2,151**
7												
8	Average Therm Use	76	9	29	43	54	63	73	84	97	115	179
9												
10												
11	**Present Bill**											
12	Total Delivery	$657.29	$165.55	$307.47	$411.56	$490.42	$559.47	$629.63	$707.94	$802.46	$939.97	$1,387.12
13	Total Supply	360.33	43.50	138.04	205.73	256.88	301.97	347.67	398.90	460.69	550.74	855.06
14		$1,017.62	$209.05	$445.51	$617.29	$747.30	$861.44	$977.30	$1,106.84	$1,263.15	$1,490.71	$2,242.18
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$809.10	$234.26	$400.97	$522.82	$615.09	$695.96	$778.12	$869.85	$980.58	$1,141.73	$1,668.71
20	Total Supply	359.05	43.34	137.55	205.00	255.96	300.90	346.44	397.49	459.06	548.79	852.03
21	Totals	$1,168.15	$277.60	$538.52	$727.82	$871.05	$996.86	$1,124.56	$1,267.34	$1,439.64	$1,690.52	$2,520.74
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$151.81	$68.71	$93.50	$111.26	$124.67	$136.49	$148.49	$161.91	$178.12	$201.76	$281.59
27	Supply	(1.28)	(0.16)	(0.49)	(0.73)	(0.92)	(1.07)	(1.23)	(1.41)	(1.63)	(1.95)	(3.03)
28	Totals	$150.53	$68.55	$93.01	$110.53	$123.75	$135.42	$147.26	$160.50	$176.49	$199.81	$278.56
29												
30												
31												
32	**Increase Percent**											
33	Delivery	23.1	41.5	30.4	27.0	25.4	24.4	23.6	22.9	22.2	21.5	20.3
34	Supply	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
35	Totals	14.8	32.8	20.9	17.9	16.6	15.7	15.1	14.5	14.0	13.4	12.4
36												
37												
38												

39 Notes: Bills include SUT
40 Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule GSG
Distribution Only

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge	12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage	2,110	116	339	602	904	1,298	1,822	2,611	3,904	6,082	11,764
3	Balancing Therms	1,497	28	158	346	569	832	1,174	1,585	2,154	2,924	4,930
4												
5												
6	**Total**	**2,110**	**116**	**339**	**602**	**904**	**1,298**	**1,822**	**2,611**	**3,904**	**6,082**	**11,764**
7												
8	Average Therm Use	176	10	28	50	75	108	152	218	325	507	980
9												
10												
11	**Present Bill**											
12	Total Delivery	$1,251.19	$292.81	$396.81	$522.49	$667.62	$854.32	$1,102.06	$1,464.36	$2,048.61	$3,013.33	$5,530.88
13	Total Supply	1,253.91	68.82	201.70	357.72	537.14	771.17	1,082.92	1,551.37	2,320.25	3,614.14	6,990.74
14		$2,505.10	$361.63	$598.51	$880.21	$1,204.76	$1,625.49	$2,184.98	$3,015.73	$4,368.86	$6,627.47	$12,521.62
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$1,794.77	$449.70	$597.06	$773.64	$977.32	$1,240.38	$1,589.83	$2,104.98	$2,940.09	$4,326.98	$7,946.24
20	Total Supply	1,252.41	68.73	201.46	357.29	536.49	770.25	1,081.62	1,549.51	2,317.48	3,609.81	6,982.37
21	Totals	$3,047.18	$518.43	$798.52	$1,130.93	$1,513.81	$2,010.63	$2,671.45	$3,654.49	$5,257.57	$7,936.79	$14,928.61
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$543.58	$156.89	$200.25	$251.15	$309.70	$386.06	$487.77	$640.62	$891.48	$1,313.65	$2,415.36
27	Supply	(1.50)	(0.09)	(0.24)	(0.43)	(0.65)	(0.92)	(1.30)	(1.86)	(2.77)	(4.33)	(8.37)
28	Totals	$542.08	$156.80	$200.01	$250.72	$309.05	$385.14	$486.47	$638.76	$888.71	$1,309.32	$2,406.99
29												
30												
31												
32	**Increase Percent**											
33	Delivery	43.4	53.6	50.5	48.1	46.4	45.2	44.3	43.7	43.5	43.6	43.7
34	Supply	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
35	Totals	21.6	43.4	33.4	28.5	25.7	23.7	22.3	21.2	20.3	19.8	19.2
36												
37												
38												

39 Notes: Bills include SUT
40 Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of 2023 TAC filing in current rates

COMPARISON OF TYPICAL BILLS
Rate Schedule GSG
Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

			Annual Usages									
	Units	**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge	12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage	2,110	116	339	602	904	1,298	1,822	2,611	3,904	6,082	11,764
3	Balancing Therms	1,497	28	158	346	569	832	1,174	1,585	2,154	2,924	4,930
4												
5												
6	**Total**	**2,110**	**116**	**339**	**602**	**904**	**1,298**	**1,822**	**2,611**	**3,904**	**6,082**	**11,764**
7												
8	Average Therm Use	176	10	28	50	75	108	152	218	325	507	980
9												
10												
11	**Present Bill**											
12	Total Delivery	$1,251.19	$292.81	$396.81	$522.49	$667.62	$854.32	$1,102.06	$1,464.36	$2,048.61	$3,013.33	$5,530.88
13	Total Supply	1,253.91	68.82	201.70	357.72	537.14	771.17	1,082.92	1,551.37	2,320.25	3,614.14	6,990.74
14		$2,505.10	$361.63	$598.51	$880.21	$1,204.76	$1,625.49	$2,184.98	$3,015.73	$4,368.86	$6,627.47	$12,521.62
15												
16												
17												
18	**Proposed Bill**											
19	Total Delivery	$1,735.42	$446.45	$587.51	$756.71	$951.90	$1,203.88	$1,538.57	$2,031.57	$2,830.30	$4,155.94	$7,615.43
20	Total Supply	1,252.41	68.73	201.46	357.29	536.49	770.25	1,081.62	1,549.51	2,317.48	3,609.81	6,982.37
21	Totals	$2,987.83	$515.18	$788.97	$1,114.00	$1,488.39	$1,974.13	$2,620.19	$3,581.08	$5,147.78	$7,765.75	$14,597.80
22												
23												
24												
25	**Increase Amount**											
26	Delivery	$484.23	$153.64	$190.70	$234.22	$284.28	$349.56	$436.51	$567.21	$781.69	$1,142.61	$2,084.55
27	Supply	(1.50)	(0.09)	(0.24)	(0.43)	(0.65)	(0.92)	(1.30)	(1.86)	(2.77)	(4.33)	(8.37)
28	Totals	$482.73	$153.55	$190.46	$233.79	$283.63	$348.64	$435.21	$565.35	$778.92	$1,138.28	$2,076.18
29												
30												
31												
32	**Increase Percent**											
33	Delivery	38.7	52.5	48.1	44.8	42.6	40.9	39.6	38.7	38.2	37.9	37.7
34	Supply	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
35	Totals	19.3	42.5	31.8	26.6	23.5	21.4	19.9	18.7	17.8	17.2	16.6
36												
37												
38												

39 Notes: Bills include SUT
40 Each band represents a decile of customers segmented by annual therm usage.
Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC

COMPARISON OF TYPICAL BILLS
Rate Schedule LVG
Distribution Only

			Annual Usages										
	Units		**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge		12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage (0-1,000)		7,025	5,652	7,907	8,286	8,938	9,554	10,058	10,362	10,843	11,170	11,578
3	Therm Usage (1,000+)		31,667	1,064	4,212	7,501	10,453	13,873	18,384	24,621	34,102	54,770	225,003
4	Demand Therms		1,084	198	361	496	592	701	822	978	1,264	1,788	5,019
5													
6	Balancing Therms		23,307	3,433	7,187	10,252	12,307	14,283	16,426	19,923	25,445	35,568	78,098
7													
8		**Total**	**38,692**	**6,716**	**12,119**	**15,787**	**19,391**	**23,427**	**28,442**	**34,984**	**44,945**	**65,941**	**236,580**
9													
10	Average Therm Use		3,224	560	1,010	1,316	1,616	1,952	2,370	2,915	3,745	5,495	19,715
11													
12													
13	**Present Bill**												
14	Total Delivery		$12,889.11	$3,923.28	$5,502.79	$6,760.56	$7,722.00	$8,782.87	$10,004.56	$11,664.62	$14,436.00	$19,774.33	$54,528.48
15	Total Supply		22,676.63	3,936.03	7,102.84	9,252.29	11,364.57	13,730.18	16,669.37	20,503.37	26,341.35	38,646.60	138,655.20
16			$35,565.74	$7,859.31	$12,605.63	$16,012.85	$19,086.57	$22,513.05	$26,673.93	$32,167.99	$40,777.35	$58,420.93	$193,183.68
17													
18													
19													
20	**Proposed Bill**												
21	Total Delivery		$15,630.68	$5,999.99	$7,981.27	$9,380.11	$10,479.33	$11,682.05	$13,028.83	$14,801.99	$17,797.60	$23,433.96	$59,246.23
22	Total Supply		22,649.10	3,931.25	7,094.22	9,241.06	11,350.77	13,713.52	16,649.14	20,478.48	26,309.37	38,599.69	138,486.90
23	Totals		$38,279.78	$9,931.24	$15,075.49	$18,621.17	$21,830.10	$25,395.57	$29,677.97	$35,280.47	$44,106.97	$62,033.65	$197,733.13
24													
25													
26													
27	**Increase Amount**												
28	Delivery		$2,741.57	$2,076.71	$2,478.48	$2,619.55	$2,757.33	$2,899.18	$3,024.27	$3,137.37	$3,361.60	$3,659.63	$4,717.75
29	Supply		(27.53)	(4.78)	(8.62)	(11.23)	(13.80)	(16.66)	(20.23)	(24.89)	(31.98)	(46.91)	(168.30)
30	Totals		$2,714.04	$2,071.93	$2,469.86	$2,608.32	$2,743.53	$2,882.52	$3,004.04	$3,112.48	$3,329.62	$3,612.72	$4,549.45
31													
32													
33													
34	**Increase Percent**												
35	Delivery		21.3	52.9	45.0	38.7	35.7	33.0	30.2	26.9	23.3	18.5	8.7
36	Supply		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
37	Totals		7.6	26.4	19.6	16.3	14.4	12.8	11.3	9.7	8.2	6.2	2.4
38													
39													
40													
41		Notes:	Bills include SUT										
42			Each band represents a decile of customers segmented by annual therm usage.										
			Assumes approval of 2023 TAC filing in current rates										

COMPARISON OF TYPICAL BILLS
Rate Schedule LVG
Including Tax Adjustment Credit, Gas Bad Debts (incl in SBC Charge) and Distribution Adjustment Charge

			Annual Usages										
	Units		**Class Avg**	**Band 1**	**Band 2**	**Band 3**	**Band 4**	**Band 5**	**Band 6**	**Band 7**	**Band 8**	**Band 9**	**Band 10**
1	Service Charge		12	12	12	12	12	12	12	12	12	12	12
2	Therm Usage (0-1,000)		7,025	5,652	7,907	8,286	8,938	9,554	10,058	10,362	10,843	11,170	11,578
3	Therm Usage (1,000+)		31,667	1,064	4,212	7,501	10,453	13,873	18,384	24,621	34,102	54,770	225,003
4	Demand Therms		1,084	198	361	496	592	701	822	978	1,264	1,788	5,019
5													
6	Balancing Therms		23,307	3,433	7,187	10,252	12,307	14,283	16,426	19,923	25,445	35,568	78,098
7													
8		**Total**	**38,692**	**6,716**	**12,119**	**15,787**	**19,391**	**23,427**	**28,442**	**34,984**	**44,945**	**65,941**	**236,580**
9													
10	Average Therm Use		3,224	560	1,010	1,316	1,616	1,952	2,370	2,915	3,745	5,495	19,715
11													
12													
13	**Present Bill**												
14	Total Delivery		$12,889.11	$3,923.28	$5,502.79	$6,760.56	$7,722.00	$8,782.87	$10,004.56	$11,664.62	$14,436.00	$19,774.33	$54,528.48
15	Total Supply		22,676.63	3,936.03	7,102.84	9,252.29	11,364.57	13,730.18	16,669.37	20,503.37	26,341.35	38,646.60	138,655.20
16			$35,565.74	$7,859.31	$12,605.63	$16,012.85	$19,086.57	$22,513.05	$26,673.93	$32,167.99	$40,777.35	$58,420.93	$193,183.68
17													
18													
19													
20	**Proposed Bill**												
21	Total Delivery		$17,757.73	$6,369.18	$8,647.50	$10,247.97	$11,545.32	$12,969.93	$14,592.41	$16,725.19	$20,268.40	$27,058.99	$72,251.98
22	Total Supply		22,649.10	3,931.25	7,094.22	9,241.06	11,350.77	13,713.52	16,649.14	20,478.48	26,309.37	38,599.69	138,486.90
23	Totals		$40,406.83	$10,300.43	$15,741.72	$19,489.03	$22,896.09	$26,683.45	$31,241.55	$37,203.67	$46,577.77	$65,658.68	$210,738.88
24													
25													
26													
27	**Increase Amount**												
28	Delivery		$4,868.62	$2,445.90	$3,144.71	$3,487.41	$3,823.32	$4,187.06	$4,587.85	$5,060.57	$5,832.40	$7,284.66	$17,723.50
29	Supply		(27.53)	(4.78)	(8.62)	(11.23)	(13.80)	(16.66)	(20.23)	(24.89)	(31.98)	(46.91)	(168.30)
30	Totals		$4,841.09	$2,441.12	$3,136.09	$3,476.18	$3,809.52	$4,170.40	$4,567.62	$5,035.68	$5,800.42	$7,237.75	$17,555.20
31													
32													
33													
34	**Increase Percent**												
35	Delivery		37.8	62.3	57.1	51.6	49.5	47.7	45.9	43.4	40.4	36.8	32.5
36	Supply		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
37	Totals		13.6	31.1	24.9	21.7	20.0	18.5	17.1	15.7	14.2	12.4	9.1
38													
39													
40													
41		Notes:	Bills include SUT										
42			Each band represents a decile of customers segmented by annual therm usage.										
			Assumes approval of proposed TAC filing, Gas Bad Debts (as part of SBC) and DAC										

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	39,041,892	4,021,862	8,979,916	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	14,684,863	1,512,747	3,377,624	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
11	S	Mains 376	CALCULATED	3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
14	S	Services 380	CALCULATED	5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
15	S	Meters 381	CALCULATED	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
16	S	Meter Installations 382	CALCULATED	52,631,537	47,983,374	4,209,056	439,073	0	33
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	0	0	0	1,521,717	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	39,074,172	7,551,967	17,939,509	10,931	638,495
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
23	S	General Plant E389-E399	CALCULATED	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
24	S	Common Plant C389-C399	CALCULATED	102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	14,286,709	1,415,779	804,020	641	284,706
26	S	Total Plant in Service	CALCULATED	10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	664,819,310	486,059,657	82,116,600	93,160,525	211,022	3,271,505
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	79,025	8,845	7,054	8	1,350
34	S	Other Rate Base Additions		1,724,917,916	1,237,711,370	217,137,885	262,034,531	372,863	7,661,268
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,945,102	-18,256,560	-2,916,359	-3,658,979	-3,094	-110,110
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-183,889,689	-31,960,043	-39,054,175	-53,764	-1,174,338
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,714,531,256	-1,231,005,541	-213,836,737	-261,476,787	-359,294	-7,852,896
39	S								
40	S	Other Rate Base Deductions		0	0	0	0	0	0
41	S	TOTAL RATE BASE		8,668,832,235	6,226,391,124	1,104,437,503	1,298,370,502	2,253,286	37,379,820
42	S								
43	S								
44	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	S								
46	S	**SUMMARY OF RESULTS**							
47	S	**DEVELOPMENT OF RETURN**							
48	S								
49	S	**RATE BASE**	CALCULATED	8,668,832,235	6,226,391,124	1,104,437,503	1,298,370,502	2,253,286	37,379,820
50	S								
51	S	**OPERATING REVENUES**							
52	S	Rate Revenues from Customers	CALCULATED	1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
53	S	Other Operating Revenues	CALCULATED	67,687,036	59,381,188	3,514,258	4,682,383	7,603	101,604
54	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
55	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
56	S	TOTAL OPERATING REVENUES		1,452,575,331	1,050,663,353	179,057,435	214,708,619	567,088	7,578,836
57	S								
58	S	**OPERATING EXPENSES**							
59	S	Operation and Maintenance Expense							
60	S	Gas Production and Supply Expense	CALCULATED	31,906,945	23,935,800	2,465,727	5,505,418	0	1
61	S	Storage Expense	CALCULATED	2,714,605	2,036,430	209,781	468,394	0	0
62	S	Transmission Expense	CALCULATED	2,593,507	1,553,951	300,340	713,388	435	25,394
63	S	Distribution Expense	CALCULATED	102,873,398	77,699,719	11,258,713	13,338,995	208,062	367,909
64	S	Customer Accounts Expense	CALCULATED	98,759,541	80,953,361	9,207,948	7,155,634	2,373	1,440,225
65	S	Customer Service & Information Expense	CALCULATED	4,034,218	3,287,677	493,290	222,739	121	30,392
66	S	Sales Expense	CALCULATED	88,423	70,127	12,936	5,339	2	19
67	S	Administrative and General Expense	CALCULATED	38,752,071	21,675,904	6,046,546	10,418,715	73,670	537,236
68	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	211,212,969	29,995,281	37,828,621	284,662	2,401,175
69	S	Depreciation Expense	CALCULATED	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
70	S	Amortization Expense	CALCULATED	2,351,634	2,067,920	194,832	68,025	48	20,808
71	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,023,027	-2,468,459	-2,845,173	-8,536	-135,526
72	S	Proforma Expense Adjustments	CALCULATED	105,999,447	79,314,562	11,944,467	14,155,911	30,181	554,325
73	S	State Income Taxes	CALCULATED	75,668,323	54,383,530	9,608,735	11,327,204	19,393	329,462
74	S	Federal Income Taxes	CALCULATED	139,157,389	100,008,538	17,725,052	20,787,882	36,667	599,249
75	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,398,132	5,306,282	6,931,688	-4,229	73,643
76	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
77	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
78	S	TOTAL OPERATING EXPENSES		812,815,512	591,155,688	97,549,947	118,888,876	400,795	4,820,206
79	S								
80	S	**OPERATING INCOME (RETURN)**		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631
81	S	Plus Operating Income Adjustment	CALCULATED						
82	S	TOTAL NET OPERATING INCOME		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631
83	S								
84	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
85	S	**INDEX RATE OF RETURN (PRESENT)**		1	1	1	1	1	1
86	S								
87	S								
88	S	**EQUALIZED RETURN AT PROPOSED ROR**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
90	S								
91	S	**RATE BASE**	CALCULATED	8,668,832,235	6,226,391,124	1,104,437,503	1,298,370,502	2,253,286	37,379,820
92	S								
93	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
94	S								
95	S	**RETURN (RATE BASE * 7.40% ROR)**		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631
96	S								
97	S	**PLUS:**							
98	S	**OPERATING EXPENSES**							
99	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	211,212,969	29,995,281	37,828,621	284,662	2,401,175
100	S	Depreciation Expense	CALCULATED	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
101	S	Amortization Expense	CALCULATED	2,351,634	2,067,920	194,832	68,025	48	20,808
102	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-19,023,027	-2,468,459	-2,845,173	-8,536	-135,526
103	S	Proforma Expense Adjustments	CALCULATED	105,999,447	79,314,562	11,944,467	14,155,911	30,181	554,325
104	S	Income Taxes	CALCULATED	214,825,712	154,392,068	27,333,787	32,115,086	56,060	928,711
105	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	16,398,132	5,306,282	6,931,688	-4,229	73,643
106	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
107	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
108	S	**TOTAL OPERATING EXPENSES**		812,815,512	591,155,688	97,549,947	118,888,876	400,795	4,820,206
109	S								
110	S	**EQUALS TOTAL COST OF SERVICE**		1,452,575,331	1,050,663,353	179,057,435	214,708,619	567,088	7,578,836
111	S								
112	S	**LESS:**							
113	S	Other Operating Revenues	CALCULATED	67,687,036	59,381,188	3,514,258	4,682,383	7,603	101,604
114	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
115	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
116	S	**EQUALS:**							
117	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
118	S								
119	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
120	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	13,931,440	1,359,023	727,829	530	282,481
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	355,269	56,756	76,191	111	2,225
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	14,286,709	1,415,779	804,020	641	284,706
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	14,286,709	1,415,779	804,020	641	284,706
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	39,041,892	4,021,862	8,979,916	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	39,041,892	4,021,862	8,979,916	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	14,684,863	1,512,747	3,377,624	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	14,684,863	1,512,747	3,377,624	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	AVGPEAK_04	5,421,128	3,248,175	627,791	1,491,173	908	53,080
37	RBP	G366 Structures & Improvements	AVGPEAK_04	0	0	0	0	0	0
38	RBP	G367 Mains	AVGPEAK_04	93,786,847	56,194,235	10,860,944	25,797,666	15,713	918,290
39	RBP	G369 Meas. & Reg. Station Equipment	AVGPEAK_04	4,336,420	2,598,252	502,177	1,192,806	727	42,459
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	AVGPEAK_04	3,772,391,917	2,260,302,858	436,860,148	1,037,660,490	632,027	36,936,395
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	1,631,647	309,809	825,847	747	24,924
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	AVGPEAK_04	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	4,484,987,779	640,513,095	312,808,899	0	3,703,317
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	3,018,317	573,103	1,527,700	1,381	46,106
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	4,488,006,097	641,086,199	314,336,599	1,381	3,749,423
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	317,951,582	110,270,842	48,821,087	0	1,532
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	1,755	333	888	1	27
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	47,983,018	4,208,988	438,893	0	27
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	356	68	180	0	5
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	47,983,374	4,209,056	439,073	0	33
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	32,605,191	3,994,393	1,885,454	0	2,986
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	6,483	1,231	3,282	3	99
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	32,611,675	3,995,624	1,888,736	3	3,085
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	102,955,181	8,127,539	1,598,014	0	810
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,092	207	553	0	17
101	RBP	Total Account G384		112,683,414	102,956,273	8,127,747	1,598,567	0	827
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	896,108	1,613,951	69,103,946	0	298,200
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	60,666,042	9,385,601	0	1,860,561
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	522,870	99,280	264,647	239	7,987
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	522,870	99,280	264,647	239	7,987
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	0	1,011,930	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	0	0	0	509,787	0
115	RBP	Total Accounts G387		1,521,717	0	0	0	1,521,717	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	39,074,172	7,551,967	17,939,509	10,931	638,495
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Not Used	not_used	0	0	0	0	0	0
152	RBP	Customer Service Related	CUSTSVSX	75,768,117	64,753,044	6,316,710	3,382,935	2,462	1,312,966
153	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	18,158,813	2,900,956	3,894,349	5,664	113,741
154	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
155	RBP	Unassigned	TOTPLT	1,393,316	1,000,330	173,857	212,448	292	6,388
156	RBP	Total Accounts C389-C399		102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
157	RBP								
158	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	229,344,924	32,625,089	38,679,316	53,784	2,344,039
159	RBP								
160	RBP								
161	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	8,393,751	818,817	438,520	319	170,196
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	8,393,751	818,817	438,520	319	170,196
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	8,393,751	818,817	438,520	319	170,196
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	42,067,900	4,333,584	9,675,919	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	7,109,257	732,353	1,635,180	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	30,105,952	5,818,729	13,821,049	8,418	491,972
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	310,280	54,376	65,732	92	1,926
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	AVGPEAK_04	1,017,890,245	609,888,973	117,876,322	279,988,006	170,537	9,966,408
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	443,986	84,302	224,720	203	6,782
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	610,332,959	117,960,624	280,212,726	170,741	9,973,190
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	AVGPEAK_04	93,669,010	56,123,631	10,847,298	25,765,253	15,693	917,136
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	56,123,631	10,847,298	25,765,253	15,693	917,136
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	941,879,849	127,667,704	56,085,079	0	1,311,381
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	1,372,810	260,663	694,838	628	20,970
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	943,252,660	127,928,367	56,779,917	628	1,332,351
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	41,220,681	13,639,927	6,145,259	0	202
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	1,138	216	576	1	17
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	41,221,819	13,640,143	6,145,836	1	219
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	31,062,601	2,354,621	235,711	0	11
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	163	31	83	0	2
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	31,062,764	2,354,652	235,794	0	14
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	21,059,419	2,653,835	1,312,627	0	5,082
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	2,820	535	1,427	1	43
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	21,062,240	2,654,371	1,314,054	1	5,125
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	53,459,006	4,125,696	820,870	0	1,173
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	588	112	298	0	9
75	RBD	Total Account G384		58,407,752	53,459,594	4,125,808	821,168	0	1,182
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	23,869	289,692	11,817,896	0	105,161
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	10,344,813	1,235,941	0	655,864
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	172,909	32,831	87,517	79	2,641
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	172,909	32,831	87,517	79	2,641
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	369,687	10,700,167	13,228,870	158	766,307
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,757,195,634	290,265,805	384,569,350	187,315	12,997,450

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	68,764,815	10,985,504	14,747,339	21,450	430,721
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	68,764,815	10,985,504	14,747,339	21,450	430,721
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Not Used	not_used	0	0	0	0	0	0
107	RBD	Customer Service Related	CUSTSVSX	38,276,434	32,711,855	3,191,067	1,708,986	1,244	663,282
108	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	9,512,371	1,519,646	2,040,028	2,967	59,582
109	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
110	RBD	Unassigned	TOTPLT	1,273,650	914,416	158,926	194,202	267	5,840
111	RBD	Total Accounts C389-C399 Reserve		52,684,679	43,138,641	4,869,638	3,943,217	4,478	728,704
112	RBD								
113	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
114	RBD								
115	RBD								
116	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	5,935,692,862	1,053,887,312	1,247,358,334	2,085,546	35,583,043
117	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	42,555,365	7,442,317	9,106,038	12,535	265,794
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	605,321,561	443,419,538	74,660,013	84,038,424	198,449	3,005,137
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	84,754	14,270	16,063	38	574
11	RBO	Total Working Capital		664,819,310	486,059,657	82,116,600	93,160,525	211,022	3,271,505
12	RBO	CEF-EC Adjustment	not_used						
13	RBO	CEF-EV Adjustment	not_used						
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,583,894,314	1,136,549,734	199,176,551	240,775,882	337,319	7,054,828
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Capital Lease Plant & Reserve Deduction	COMPLT	96,280	79,025	8,845	7,054	8	1,350
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	141,023,603	101,161,636	17,961,334	21,258,649	35,544	606,440
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,389,833,506	1,723,850,052	299,263,330	355,202,110	583,892	10,934,122
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	(24,945,102)	(18,256,560)	(2,916,359)	(3,658,979)	(3,094)	(110,110)
23	RBO	IAP Adjustment	not_used						
24	RBO	GSMP II EXT Adjustment	TOTPLT	(256,132,009)	(183,889,689)	(31,960,043)	(39,054,175)	(53,764)	(1,174,338)
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT						
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	25,399,369	4,414,412	5,394,274	7,426	162,203
28	RBO	Liberalized Depreciation - Production	BALANCE_04	(1,955,963)	(1,467,315)	(151,154)	(337,493)		
29	RBO	Cost of Removal	TOTPLT	9,569,770	6,870,606	1,194,112	1,459,167	2,009	43,876
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	(160,793)	(115,343)	(20,479)	(24,239)	(41)	(691)
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	3,014,922	532,690	627,959	1,075	18,265
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	(1,761,556,867)	(1,264,707,780)	(219,806,318)	(268,596,456)	(369,764)	(8,076,549)
35	RBO	Total Deferred Income Taxes and Credits		(1,714,531,256)	(1,231,005,541)	(213,836,737)	(261,476,787)	(359,294)	(7,852,896)
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		(1,995,608,367)	(1,433,151,790)	(248,713,139)	(304,189,941)	(416,152)	(9,137,344)
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,668,832,235	6,226,391,124	1,104,437,503	1,298,370,502	2,253,286	37,379,820

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	0	658,892	788,323	0	0
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	40,880,111	0	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	14,085,539	2,400,503	2,878,454	7,603	101,604
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	4,415,538	454,862	1,015,606	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	59,381,188	3,514,258	4,682,383	7,603	101,604
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,452,575,331	1,050,663,353	179,057,435	214,708,619	567,088	7,578,836

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	211,536	21,791	48,655	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	22,349,708	2,302,333	5,140,593	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	1,374,514	141,594	316,148	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	23,935,758	2,465,719	5,505,396	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72	42	8	21	0	1
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72	42	8	21	0	1
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	23,935,800	2,465,727	5,505,418	0	1
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	6,681	688	1,537	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699	2,029,749	209,093	466,857		
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	2,036,430	209,781	468,394	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507	1,553,951	300,340	713,388	435	25,394
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	1,553,951	300,340	713,388	435	25,394
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	15,174,273	2,423,985	3,041,227	2,572	91,520
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	1,496,138	289,166	686,848	418	24,449
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	4,550	879	2,089	1	74
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	308,296	59,586	141,533	86	5,038
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	8,464,742	2,136,903	890,323	0	93
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	17,355,157	0	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	11,166,159	1,332,116	1,510,775	1,065	40,072
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
49	E	Total Distribution Operation		71,400,849	56,744,669	6,769,606	7,677,520	5,413	203,641
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	5,752,336	1,008,078	1,218,621	1,707	35,706
55	E	G887 Mains	PLT_376	8,706,285	5,216,446	1,008,196	2,394,944	1,459	85,240
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	603,902	116,719	277,239	169	9,869
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	1,890,718	365,429	867,991	529	30,897
59	E	G892 Services	SERVICES	3,610,466	2,974,434	424,881	208,327	339	2,485
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	4,510,880	1,564,448	692,640	0	22
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	6,334	1,357	1,711	61	50
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	0	198,384	0
67	E	Total Distribution Maintenance		31,472,549	20,955,051	4,489,107	5,661,476	202,649	164,268
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	77,699,719	11,258,713	13,338,995	208,062	367,909
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	105,225,900	14,234,561	20,026,195	208,496	393,303
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	11,695,648	984,362	227,828	0	0
76	E	- Meter O&M Related	METERPLT	38,249	23,265	11,125	3,740	0	119
77	E	G903 Customer Records and Collection							
78	E	- SONP/RNP	CUSTAVG_06	526,534	477,008	40,157	9,334	8	27
79	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
80	E	- Meter Reading Related	MRCOST_07	63,202	57,267	4,820	1,116	0	0
81	E	- Billing Related	BILLING_06	16,558,655	13,225,534	1,341,715	1,310,000	1,164	680,242
82	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	23,623,844	2,005,203	393,770	159	50,309
83	E	- Utility Work Related	UTILWORK_04	2,712,621	2,151,329	396,835	163,794	70	592
84	E	- Remaining	BILLING_06	13,832,442	11,048,085	1,120,815	1,094,322	972	568,247
85	E	Not used	not_used	0	0	0	0	0	0
86	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
87	E								
88	E	G904 Uncollectible Accounts	EXP_904	26,046,715	18,651,381	3,302,917	3,951,730	0	140,687

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
90	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	80,953,361	9,207,948	7,155,634	2,373	1,440,225
91	E								
92	E	CUSTOMER SERVICE & INFO EXPENSES							
93	E	G907 & 908 - Customer Service & Information							
94	E	- Billing	BILLING_06	37,379	29,855	3,029	2,957	3	1,536
95	E	- Acct Maint related	ACCTMAINT_06	746,413	676,291	57,404	11,273	5	1,440
96	E	- Utility work related	UTILWORK_04	1,684,915	1,336,275	246,490	101,739	44	368
97	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
98	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
99	E	G910 - Misc Cust Service & Info							
100	E	- Utility work related	UTILWORK_04	911,953	723,253	133,412	55,066	24	199
101	E	- Remaining	BILLING_06	653,558	522,002	52,957	51,705	46	26,849
102	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	3,287,677	493,290	222,739	121	30,392
103	E								
104	E	SALES EXPENSES							
105	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	70,127	12,936	5,339	2	19
106	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
107	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
108	E								
109	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	70,127	12,936	5,339	2	19
110	E								
111	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	189,537,065	23,948,735	27,409,906	210,992	1,863,939
112	E								
113	E	ADMINISTRATIVE & GENERAL EXPENSE							
114	E	G920 A&G Salaries	TOMXFUEL904	6,954,680	5,240,842	752,957	881,778	8,847	70,255
115	E	G921 Office Supplies & Exp	TOMXFUEL904	652,569	491,757	70,651	82,739	830	6,592
116	E	G923 Outside Services Employed							
117	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
118	E	- Remaining	TOMXFUEL904	61,043,177	46,000,343	6,608,916	7,739,612	77,655	616,650
119	E	G924 Property Insurance	TOTPLT	296,480	212,857	36,995	45,206	62	1,359
120	E	G925 Injuries & Damages	LABOR	15,351,785	13,054,660	1,092,067	1,093,967	7,995	103,096
121	E	G926 Employee Pension & Benefits							
122	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
123	E	- Remaining	LABOR	-60,778,346	-51,683,934	-4,323,538	-4,331,059	-31,654	-408,162
124	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	3,007,028	570,960	1,521,986	1,376	45,934
125	E	G929 Duplicate Charges - credit	INTRAREV	764,611	0	36,250	728,361	0	0
126	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	1,149,789	218,316	581,957	526	17,564
127	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	2,125,615	403,601	1,075,865	973	32,470
128	E	G931 Rents	AGEXP	3,713,155	2,076,947	579,369	998,303	7,059	51,477
129	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
130	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
131	E	Not Used	not_used	0	0	0	0	0	0
132	E	TOTAL A&G EXPENSE		38,752,071	21,675,904	6,046,546	10,418,715	73,670	537,236

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	E								
134	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	211,212,969	29,995,281	37,828,621	284,662	2,401,175
135	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	1,253	129	288	0	0
5	DE	Storage Plant	BALANCE_04	114,612	85,979	8,857	19,776	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	702,605	135,796	322,552	196	11,482
7	DE	Distribution Plant	DISTPLT	182,874,076	131,224,338	22,996,628	27,799,624	38,946	814,540
8	DE	General and Common Plant	COMGENPLT	19,528,227	14,778,887	2,102,347	2,492,478	3,466	151,049
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	1,020,727	99,573	53,326	39	20,697
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	CHOICE_04	1,127,553	1,029,117	86,615	11,792	10	19
16	DE	Metering	METERPLT	29,719	18,076	8,644	2,906	0	92
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	2,067,920	194,832	68,025	48	20,808
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	2,067,920	194,832	68,025	48	20,808
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	148,860,982	25,438,589	30,702,743	42,657	997,878

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-1,730	-145	-145	-1	-14
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-9,729,897	-1,691,057	-2,066,419	-2,845	-62,136
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-51,431	-4,302	-4,310	-31	-406
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-9,239,969	-772,955	-774,300	-5,659	-72,970
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-19,023,027	-2,468,459	-2,845,173	-8,536	-135,526
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-682,298	-580,204	-48,536	-48,620	-355	-4,582
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	4,884,054	3,495,932	619,084	740,695	1,973	26,370
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	6,746,929	5,737,370	479,951	480,786	3,514	45,310
26	EO	Payroll Taxes (Rate Year)	LABOR	463,867	394,458	32,998	33,055	242	3,115
27	EO	Interest Syncronization	TOTPLTNET	-1,266,764	-908,698	-161,340	-190,959	-319	-5,447
28	EO	- add'l tax effects on rev req	TOTPLTNET	-495,322	-355,314	-63,086	-74,668	-125	-2,130
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	15,610,563	13,274,717	1,110,475	1,112,407	8,130	104,834
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	0	0	0	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-148,938	-25,886	-31,631	-44	-951
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-58,237	-10,122	-12,368	-17	-372
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	-328,894	-236,129	-41,039	-50,149	-69	-1,508
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	262,863	188,722	32,800	40,081	55	1,205
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-4,259,410	-740,286	-904,606	-1,245	-27,201
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	14,761,516	10,598,014	1,841,936	2,250,788	3,099	67,680
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	150,424	107,997	18,770	22,936	32	690
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	71,386,007	51,445,373	8,846,974	10,736,301	14,933	342,426
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		105,999,447	79,314,562	11,944,467	14,155,911	30,181	554,325
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		81,518,725	60,291,535	9,476,008	11,310,738	21,645	418,799
61	EO	COLI Interest Expense Recovery	LABOR	727,815	618,910	51,774	51,864	379	4,888

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,452,575,331	1,050,663,353	179,057,435	214,708,619	567,088	7,578,836
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	211,212,969	29,995,281	37,828,621	284,662	2,401,175
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	148,860,982	25,438,589	30,702,743	42,657	997,878
7	TI	OTHER OPERATING EXPENSES	CALCULATED	81,518,725	60,291,535	9,476,008	11,310,738	21,645	418,799
8	TI	NET OPERATING INCOME BEFORE TAXES		883,291,047	630,297,866	114,147,557	134,866,517	218,123	3,760,984
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	72,322,099	12,840,850	15,198,154	25,411	433,553
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		782,470,979	557,975,766	101,306,706	119,668,363	192,712	3,327,431
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	40,732	7,232	8,560	14	244
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	37,485	6,656	7,877	13	225
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	299,307	52,020	63,566	88	1,911
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-786,060	-139,566	-165,187	-276	-4,712
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP II	TOTPLT	8,262	5,932	1,031	1,260	2	38
23	TI	Deferred Return on CIP II	TOTPLT	18,055	12,963	2,253	2,753	4	83
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-299,856	-53,240	-63,013	-105	-1,798
31	TI	Material Supplies & Reserves	TOTPLT	78,535	56,384	9,800	11,975	16	360
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-326,887	-58,039	-68,694	-115	-1,960
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-233,300	-41,423	-49,027	-82	-1,399
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-10	-2	-2	0	0
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	5,590	972	1,187	2	36
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-299,538	-25,057	-25,101	-183	-2,366
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-12,390	-1,036	-1,038	-8	-98
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-15,689,941	-2,698,173	-3,274,384	-4,554	-104,434
60	TI	Customer Advances	TOTPLTNET	294,687	211,390	37,532	44,423	74	1,267
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-3,724	-311	-312	-2	-29
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-4,930,650	-412,466	-413,183	-3,020	-38,939
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	666	116	142	0	4
65	TI	Entertainment (100%)	LABOR	36,298	30,866	2,582	2,587	19	244
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	750,083	130,365	159,301	219	4,790
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-44,612,140	-7,671,875	-9,310,252	-12,949	-296,943
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	118,530	9,915	9,933	73	936
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-54,362	-9,448	-11,545	-16	-347
75	TI	R&D Expenditure	TOTPLT	-16,866	-12,109	-2,105	-2,572	-4	-77
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-372,866	-64,804	-79,189	-109	-2,381
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	427,168	74,242	90,721	125	2,728
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	103,567	8,664	8,679	63	818
81	TI	State NOL CF (c)	DEPREXP	7,732,062	5,572,224	958,246	1,162,885	1,617	37,089
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-58,216	-10,118	-12,364	-17	-372
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	102,055	17,737	21,674	30	652
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	REVREQ	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-390,495	-32,666	-32,723	-239	-3,084
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-605,900	-107,578	-127,327	-213	-3,632
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
95	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
96	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
97	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
98	TI	AFUDC / IDC	TOTPLT	-345,079	-247,749	-43,059	-52,616	-72	-1,582
99	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
100	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
101	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
102	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
103	TI	Deferred Comp - officers	LABOR	-15,155	-12,887	-1,078	-1,080	-8	-102
104	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
105	TI	Accrued vacation pay adjustment	LABOR	-257,985	-219,382	-18,352	-18,384	-134	-1,733
106	TI	3rd Party Claims	TOTPLT	-975	-700	-122	-149	0	-4
107	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
108	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
109	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
110	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-6,616,159	-553,464	-554,427	-4,052	-52,250
111	TI	Unallowable OPEB Amortization	LABOR	47,224,310	40,158,021	3,359,356	3,365,200	24,595	317,138
112	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
113	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
114	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	1,281,360	107,190	107,377	785	10,119
115	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
116	TI	Deferred Depreciation & Return on CIP II	TOTPLTNET	0	0	0	0	0	0
117	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
118	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
119	TI	Restricted Stock - Permanent	LABOR	-67,594	-57,480	-4,808	-4,817	-35	-454
120	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
121	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
122	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
123	TI	Penalties	not_used	0	0	0	0	0	0
124	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
125	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-732,623	-130,078	-153,957	-257	-4,392
126	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
127	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
128	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
129	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
130	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-27,361,102	-7,292,961	-9,351,245	1,287	-144,404
131	TI								
132	TI								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
134	TI								
135	TI	**TAX ADJUSTMENTS - STATE**							
136	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
137	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	46,434,906	8,070,391	9,861,765	13,576	296,538
138	TI	State Tax Depreciation	DEPREXP	37,759,415	27,211,876	4,679,581	5,678,934	7,899	181,125
139	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
140	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
141	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	73,646,782	12,749,971	15,540,700	21,475	477,663
142	TI								
143	TI	**TAXABLE NET INCOME - STATE**		840,759,145	604,261,447	106,763,717	125,857,818	215,474	3,660,690
144	TI	State Tax Liability		75,668,323	54,383,530	9,608,735	11,327,204	19,393	329,462
145	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
146	TI	**TOTAL STATE INCOME TAX LIABILITY**		75,668,323	54,383,530	9,608,735	11,327,204	19,393	329,462
147	TI								
148	TI	**TAXABLE NET INCOME - FEDERAL**		662,654,232	476,231,134	84,405,011	98,989,914	174,607	2,853,565
149	TI	Federal Tax Liability		139,157,389	100,008,538	17,725,052	20,787,882	36,667	599,249
150	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
151	TI	Not Used	not_used	0	0	0	0	0	0
152	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		139,157,389	100,008,538	17,725,052	20,787,882	36,667	599,249
153	TI								
154	TI	**TOTAL INCOME TAX EXPENSE**		214,825,712	154,392,068	27,333,787	32,115,086	56,060	928,711
155	TI								
156	TI	**TAX RATES**							
157	TI	FEDERAL TAX RATE - CURRENT		21.000%					
158	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
159	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.0					
160	TI	EFFECTIVE TAX RATE		28.110%					
161	TI	COMPOSITE RATE		28.110%					
162	TI	1 - EFFECTIVE TAX RATE		71.89000%					
163	TI								
164	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
165	TI								
166	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
167	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
168	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
169	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
170	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	10	2	2	0	0
171	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-22,792	-3,961	-4,841	-7	-146
172	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	786,060	139,566	165,187	276	4,712
173	TI	CECL Reserve	not_used	0	0	0	0	0	0
174	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
175	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
176	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
178	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
179	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
180	TI	COVID Deferrals	not_used	0	0	0	0	0	0
181	TI	Current SHARE -- FT	DEPREXP	5,506,769	3,968,534	682,462	828,206	1,152	26,415
182	TI	Customer Advances	TOTPLTNET	-294,687	-211,390	-37,532	-44,423	-74	-1,267
183	TI	Deduction for Retention Payments (c)	LABOR	4,379	3,724	311	312	2	29
184	TI	Deferred Employer ER FICA	LABOR	5,798,258	4,930,650	412,466	413,183	3,020	38,939
185	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
186	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
187	TI	Injuries & Damages - FT	TOTPLT	-264,256	-189,722	-32,974	-40,293	-55	-1,212
188	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
189	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
190	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
191	TI	Plant Related	DEPREXP	62,706,788	45,190,566	7,771,346	9,430,965	13,117	300,793
192	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
193	TI	R & D Credits CF	TOTPLT	-67,859	-48,719	-8,467	-10,347	-14	-311
194	TI	RE - Lease Liability	TOTPLT	519,350	372,866	64,804	79,189	109	2,381
195	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-427,168	-74,242	-90,721	-125	-2,728
196	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	733,247	127,438	155,726	214	4,683
197	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
198	TI	Severance Pay (nc)	LABOR	-121,791	-103,567	-8,664	-8,679	-63	-818
199	TI	State NOL CF (c)	DEPREXP	-7,732,062	-5,572,224	-958,246	-1,162,885	-1,617	-37,089
200	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-102,055	-17,737	-21,674	-30	-652
201	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
202	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
203	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
204	TI	AFUDC / IDC	TOTPLT	345,079	247,749	43,059	52,616	72	1,582
205	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-299,307	-52,020	-63,566	-88	-1,911
206	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
207	TI	Deferred Comp - officers	LABOR	15,155	12,887	1,078	1,080	8	102
208	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
209	TI	Accrued vacation pay adjustment	LABOR	257,985	219,382	18,352	18,384	134	1,733
210	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
211	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
212	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
213	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
214	TI	Pension Accrual Adjustment	LABOR	7,780,352	6,616,159	553,464	554,427	4,052	52,250
215	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-40,158,021	-3,359,356	-3,365,200	-24,595	-317,138
216	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
217	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
218	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
219	TI	PIP Adjustment	LABOR	455,695	387,508	32,416	32,473	237	3,060
220	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Misc	TOTPLT	0	0	0	0	0	0
222	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
223	TI	Deferred Return on CIP II	TOTPLT	-18,055	-12,963	-2,253	-2,753	-4	-83
224	TI	Deferred Depreciation on CIP II	TOTPLT	-8,262	-5,932	-1,031	-1,260	-2	-38
225	TI	Investment Tax Credit	TOTPLT	-493,265	-354,139	-61,549	-75,211	-104	-2,262
226	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-40,732	-7,232	-8,560	-14	-244
227	TI	3rd Party Claims	TOTPLT	975	700	122	149	0	4
228	TI	Customer Connections Fees		0	0	0	0	0	0
229	TI	Legal Reserves (nc)	TOTPLTNET	418,012	299,856	53,240	63,013	105	1,798
230	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-56,336	-10,003	-11,839	-20	-338
231	TI	Stock Based Compensation	TOTPLTNET	325,229	233,300	41,423	49,027	82	1,399
232	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	16,398,132	5,306,282	6,931,688	-4,229	73,643
233	TI								
234	TI	**This Section is not used at this time**							
235	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
236	TI	Not Used	not_used	0	0	0	0	0	0
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	**OPERATING INCOME ADJUSTED**		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	583,871	60,147	134,294	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	306,054	31,528	70,395	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	289,559	55,965	132,931	81	4,732
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	2,641,804	501,613	1,337,131	1,209	40,355
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	10,503,551	1,677,869	2,105,122	1,780	63,350
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	820,014	158,488	376,452	229	13,400
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	6,306,606	1,592,087	663,330	0	69
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	63,057,319	0	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	4,148,020	494,856	561,225	396	14,886
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	-35	-7	-18	0	-1
21	LR	Total Operation		97,081,101	87,477,279	4,424,907	5,043,241	3,614	132,059
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	728,666	127,696	154,367	216	4,523
26	LR	G887 Mains	EXP_887	4,445,965	2,663,838	514,847	1,223,006	745	43,529
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	1,309,403	253,075	601,121	366	21,397
29	LR	G892 Services	EXP_892	2,126,460	1,751,856	250,243	122,699	200	1,464
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	3,362,194	1,166,064	516,261	0	16
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	2,166	464	585	67,862	17
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	9,818,123	2,312,389	2,618,038	69,389	70,946
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	97,295,402	6,737,296	7,661,279	73,003	203,005
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	38,650,888	3,663,362	1,987,637	1,472	806,207
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	2,451,159	367,777	166,065	90	22,659
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	2,797	516	213	0	1
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	3,890,088	1,085,150	1,869,805	13,221	96,416
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	143,469,817	12,001,740	12,022,619	87,868	1,133,019

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	-1,700,938	-175,221	-391,228	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	6,280,141	646,943	1,444,478	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	7	1	3	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improvemer	PLT_3745	2,620,552	1,880,421	329,537	398,364	558	11,672
10	CA	G376 Mains	PLT_376	226,633,216	135,789,241	26,244,339	62,342,774	37,987	2,218,875
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	34,194,053	6,608,857	15,697,816	9,561	558,777
13	CA	G380 Services	SERVICES	505,466,924	416,422,163	59,483,542	29,165,898	47,429	347,892
14	CA	G381 Meters	PLT_381	58,899,779	39,256,803	13,614,871	6,027,912	0	193
15	CA	G382 Meter Installations	PLT_382	-1,810,761	-1,650,843	-144,810	-15,106	0	-1
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,034,053	181,898	52,323	0	59
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	169,884	5,465,993	6,913,035	42	190,259
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	628,095,774	111,784,228	120,583,014	95,577	3,327,725
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	18,916,156	3,021,945	4,056,769	5,901	118,485
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	651,591,138	115,277,897	125,693,036	101,478	3,446,210

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	77,879	15,468	29,997	0	1,403
6	AF	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1	1	0	0	0	0
7	AF								
8	AF	**COMMODITY RELATED**							
9	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
10	AF	Balancing therms - delivery	BALANCE_04	1,793,060	1,345,110	138,565	309,385	0	0
11	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
12	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
13	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
14	AF								
15	AF	**BILLING DETERMINANTS**							
16	AF	Number of Customers		1,894,095	1,728,739	145,499	19,809	16	32
17	AF	Transported Gas at Meter (calendar)		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
18	AF								
19	AF								
20	AF	**CUSTOMER RELATED**							
21	AF	G380 services - access	SERVICES_03	1,215,746,207	1,001,946,668	143,090,682	69,881,536	0	827,321
22	AF	Cust Installns LDC G879 - delivery	CINST_04	100	100	0	0	0	0
23	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	598,870	50,415	11,719	9	34
24	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	598,870	50,415	11,719	9	34
25	AF	G381 meters - measurement	SMMETERS_07	95,373,410	63,566,590	22,045,940	9,760,574	0	306
26	AF								
27	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	16,641,744	1,688,285	1,648,379	1,464	855,952
28	AF	Competitive Service work - delivery	COMPSVSWK_04	100	100	0	0	0	0
29	AF								
30	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	60,880,342	5,167,551	1,014,774	411	129,650
31	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,257	136,288,569	11,955,000	1,246,610	0	78
32	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	23,488,422	2,877,517	1,358,260	0	2,151
33	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	45,273,401	3,573,995	702,709	0	356
34	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	527,983	950,933	40,715,751	0	175,698
35	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	5,728,862	886,308	0	175,698
36	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	252,625,678	34,242,308	15,042,822	0	351,731
37	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	26,782,366	8,862,287	3,992,767	0	131
38	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	65,486,599	4,964,044	496,929	0	24
39	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	3,992,277	503,093	248,837	0	963
40	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,043,509	697,932	138,864	0	198
41	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	13,538	164,305	6,702,764	0	59,644
42	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	940,755	112,396	0	59,644
43	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
44	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AF**	**ALLOCATION FACTOR TABLE**							
46	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AF								
48	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	0	1	0
49	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	14,755,434	1,241,888	287,431	0	0
50	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	5,374,648	991,409	409,204	176	1,480
51	AF	Direct SLG - access	DIRSLG_03	1	0	0	0	1	0
52	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
53	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
54	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
55	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
56	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
57	AF	Choice - delivery	CHOICE_04	1,894,095	1,728,739	145,499	19,809	16	32
58	AF								
59	AF								
60	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
61	AF								
62	AF								
63	AF	**Plant Related**							
64	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
65	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	14,286,709	1,415,779	804,020	641	284,706
66	AF	Production Plant Total	PRODPLT	52,043,670	39,041,892	4,021,862	8,979,916	0	0
67	AF	Storage Plant Total	STORPLT	19,575,233	14,684,863	1,512,747	3,377,624	0	0
68	AF	Transmission Plant Total	TRANPLT	103,544,395	62,040,662	11,990,912	28,481,645	17,348	1,013,828
69	AF	Distribution Plant Total	DISTPLT	10,498,076,770	7,533,069,762	1,320,145,353	1,595,866,388	2,235,754	46,759,512
70	AF	G391-G398 General Plant	GENPLT	200,812,197	145,432,738	23,233,566	31,189,583	45,366	910,945
71	AF	Common Plant	COMPLT	102,234,955	83,912,187	9,391,523	7,489,732	8,419	1,433,095
72	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	229,344,924	32,625,089	38,679,316	53,784	2,344,039
73	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	7,648,837,179	1,337,670,874	1,636,705,572	2,253,102	47,773,340
74	AF	Total Plant	TOTPLT	10,993,079,074	7,892,468,811	1,371,711,742	1,676,188,908	2,307,527	50,402,086
75	AF								
76	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	7,166,610,181	1,144,899,800	1,536,955,091	2,235,514	44,889,372
77	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	69,254,169	12,136,562	14,671,363	20,554	429,877
78	AF	Acct G376 - Mains	PLT_376	3,775,184,891	2,261,934,505	437,169,958	1,038,486,336	632,773	36,961,319
79	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
80	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	171,354,314	33,118,514	78,665,388	47,914	2,800,160
81	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	4,488,006,097	641,086,199	314,336,599	511,168	3,749,423
82	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	6,749,940,601	1,078,256,156	1,352,822,936	1,143,942	40,710,742
83	AF	Acct G381 - House Meters	PLT_381	477,048,047	317,953,337	110,271,175	48,821,975	1	1,559
84	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	47,983,374	4,209,056	439,073	0	33
85	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	366,459,581	175,245,553	58,911,296	240	1,870,140
86	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	501,504,659	126,603,602	52,748,351	4	5,504
87	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	183,551,322	16,332,427	3,926,376	4	3,945
88	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	135,567,948	12,123,371	3,487,303	3	3,912

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
90	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AF								
92	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	1,941,847	62,478,553	79,018,841	479	2,174,735
93	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
94	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	0	1,011,930	0
95	AF								
96	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,956,775,950	317,824,430	428,830,574	221,981	14,819,043
97	AF	Total Net Plant	TOTPLTNET	8,274,607,096	5,935,692,862	1,053,887,312	1,247,358,334	2,085,546	35,583,043
98	AF								
99	AF								
100	AF	**Revenue Related**							
101	AF	Total Operating Revenue	TOTREV	1,452,575,331	1,050,663,353	179,057,435	214,708,619	567,088	7,578,836
102	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	208,088,289	0	9,865,527	198,222,762	0	0
103	AF								
104	AF								
105	AF	**Expense Related**							
106	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	1,586,050	163,385	364,803	0	0
107	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	2,036,430	209,781	468,394	0	0
108	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	1,553,951	300,340	713,388	435	25,394
109	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	42	8	21	0	1
110	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	3,411,311	647,723	1,726,611	1,561	52,109
111	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
112	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	15,174,273	2,423,985	3,041,227	2,572	91,520
113	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	1,808,984	349,632	830,469	506	29,561
114	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	8,464,742	2,136,903	890,323	0	93
115	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	17,355,157	0	0	0	0
116	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	11,166,159	1,332,116	1,510,775	1,065	40,072
117	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
118	AF	Acct 881 - Rents	EXP_881	-1,088,602	-635,958	-120,753	-321,886	-291	-9,715
119	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	5,752,336	1,008,078	1,218,621	1,707	35,706
120	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	5,216,446	1,008,196	2,394,944	1,459	85,240
121	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
122	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	2,494,620	482,148	1,145,231	698	40,765
123	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	2,974,434	424,881	208,327	339	2,485
124	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	4,510,880	1,564,448	692,640	0	22
125	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	6,334	1,357	1,711	198,446	50
126	AF								
127	AF	Distr Oper Exp	DISTEXPO	71,400,849	56,744,669	6,769,606	7,677,520	5,413	203,641
128	AF	Distr Maint Exp	DISTEXPM	31,472,549	20,955,051	4,489,107	5,661,476	202,649	164,268
129	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	3,287,677	493,290	222,739	121	30,392
130	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
131	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	65,589,657	6,398,322	3,426,643	2,494	1,329,929
132	AF	Sales Expense	SALESEXP	88,423	70,127	12,936	5,339	2	19

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF	**ALLOCATION FACTOR TABLE CONTINUED**							
134	AF	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
135	AF								
136	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	189,537,065	23,948,735	27,409,906	210,992	1,863,939
137	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	192,561,588	26,692,364	33,876,891	284,662	2,260,488
138	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	168,625,830	24,226,646	28,371,495	284,662	2,260,488
139	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	21,675,904	6,046,546	10,418,715	73,670	537,236
140	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	62,301,980	5,905,031	3,203,904	2,373	1,299,538
141	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	862,804,108	145,273,178	163,521,657	386,140	5,847,385
142	AF								
143	AF	Depreciation Expense (total)	DEPREXP	203,691,216	146,793,062	25,243,756	30,634,719	42,609	977,070
144	AF								
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	75,668,323	54,383,530	9,608,734	11,327,204	19,393	329,462
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-33,541,862	-2,805,891	-2,810,773	-20,543	-264,889
147	AF								
148	AF	**Labor Expense Related**							
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	87,477,279	4,424,907	5,043,241	3,614	132,059
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	9,818,123	2,312,389	2,618,038	69,389	70,946
151	AF	Total Labor	LABOR	168,715,063	143,469,817	12,001,740	12,022,619	87,868	1,133,019
152	AF								
153	AF	**REVENUES AND BILLING DETERMINANTS**							
154	AF								
155	AF	Base Rate Sales Revenue	SALESREV	1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
156	AF								
157	AF	Residential Service Gas	REVRSG	991,282,164	991,282,164	0	0	0	0
158	AF	General Service Gas	REVGSG	175,543,177	0	175,543,177	0	0	0
159	AF	Large Volume Service Gas	REVLVG	210,026,237	0	0	210,026,237	0	0
160	AF	Street Light Gas	REVSLG	559,485	0	0	0	559,485	0
161	AF	Firm Transportation Gas Service	REVTSGF	7,477,232	0	0	0	0	7,477,232
162	AF								
163	AF								
164	AF	Total Rev Req @ desired ROR	REVREQ	1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
165	AF								
166	AF								
167	AF	**PRESENT REVENUES FROM SALES INPUT**							
168	AF								
169	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
170	AF	Sales of Gas Revenues - Rates		1,101,761	808,939	129,770	150,330	438	12,284
171	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
172	AF								
173	AF	**RATE OF RETURN**							
174	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.624295	0.123994	0.240464	0.000000	0.011247
6	AP								
7	AP	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
8	AP	**COMMODITY RELATED**							
9	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
10	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
11	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
12	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
13	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AF								
15	AP	**BILLING DETERMINANTS**							
16	AP	Number of Customers		1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
17	AP	Transported Gas at Meter (calendar)		1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
18	AP								
19	AP								
20	AP	**CUSTOMER RELATED**							
21	AP	G380 services - access	SERVICES_03	1.000000	0.824141	0.117698	0.057480	0.000000	0.000681
22	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
24	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.905940	0.076266	0.017728	0.000014	0.000052
25	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
26	AP								
27	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.798708	0.081028	0.079113	0.000070	0.041081
28	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
29	AF								
30	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.906056	0.076906	0.015102	0.000006	0.001930
31	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.911689	0.079972	0.008339	0.000000	0.000001
32	AP	G383 house regulators - access	HOUSEREG_03	1.000000	0.847152	0.103783	0.048988	0.000000	0.000078
33	AP	G384 house reg install - access	HSEREGINST_03	1.000000	0.913683	0.072128	0.014182	0.000000	0.000007
34	AP	G385 lrg regulators - access	LRGREG_03	1.000000	0.012461	0.022443	0.960949	0.000000	0.004147
35	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.843613	0.130515	0.000000	0.025873
36	AP	G380 services - reserve - access	SERVICESR_03	1.000000	0.835782	0.113287	0.049767	0.000000	0.001164
37	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.675682	0.223583	0.100732	0.000000	0.000003
38	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.923028	0.069968	0.007004	0.000000	0.000000
39	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	0.841335	0.106022	0.052440	0.000000	0.000203
40	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	0.915288	0.070637	0.014054	0.000000	0.000020
41	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	0.001951	0.023674	0.965781	0.000000	0.008594
42	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.845398	0.101003	0.000000	0.053598
43	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
45	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
46	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AP								
48	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
49	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.906089	0.076261	0.017650	0.000000	0.000000
50	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218
51	AP	Direct SLG - access	DIRSLG_03	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
52	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Choice - delivery	CHOICE_04	1.000000	0.912699	0.076817	0.010458	0.000008	0.000017
58	AP								
59	AP								
60	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP								
62	AP								
63	AP	**Plant Related**							
64	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.850812	0.084313	0.047882	0.000038	0.016955
66	AP	Production Plant Total	PRODPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
67	AP	Storage Plant Total	STORPLT	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
68	AP	Transmission Plant Total	TRANPLT	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
69	AP	Distribution Plant Total	DISTPLT	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
70	AP	G391-G398 General Plant	GENPLT	1.000000	0.724223	0.115698	0.155317	0.000226	0.004536
71	AP	Common Plant	COMPLT	1.000000	0.820778	0.091862	0.073260	0.000082	0.014018
72	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.756796	0.107657	0.127635	0.000177	0.007735
73	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.716637	0.125329	0.153347	0.000211	0.004476
74	AP	Total Plant	TOTPLT	1.000000	0.717949	0.124780	0.152477	0.000210	0.004585
75	AP								
76	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.724223	0.115698	0.155317	0.000226	0.004536
77	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
78	AP	Acct G376 - Mains	PLT_376	1.000000	0.599159	0.115801	0.275082	0.000168	0.009791
79	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
81	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
82	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.731870	0.116911	0.146681	0.000124	0.004414
83	AP	Acct G381 - House Meters	PLT_381	1.000000	0.666502	0.231153	0.102342	0.000000	0.000003
84	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.911685	0.079972	0.008342	0.000000	0.000001
85	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.608245	0.290870	0.097780	0.000000	0.003104
86	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
87	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.900582	0.080134	0.019264	0.000000	0.000019
88	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	0.896717	0.080190	0.023067	0.000000	0.000026

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
90	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AP								
92	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.013336	0.429068	0.542658	0.000003	0.014935
93	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
94	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
95	AP								
96	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.719807	0.116913	0.157747	0.000082	0.005451
97	AP	Total Net Plant	TOTPLTNET	1.000000	0.717338	0.127364	0.150745	0.000252	0.004300
98	AP								
99	AP								
100	AP	**Revenue Related**							
101	AP	Total Operating Revenue	TOTREV	1.000000	0.723311	0.123269	0.147812	0.000390	0.005218
102	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.000000	0.047410	0.952590	0.000000	0.000000
103	AP								
104	AP								
105	AP	**Expense Related**							
106	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
107	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.750176	0.077279	0.172546	0.000000	0.000000
108	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
109	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
110	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
111	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
112	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.731870	0.116911	0.146681	0.000124	0.004414
113	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
114	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.736573	0.185946	0.077473	0.000000	0.000008
115	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
116	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.794734	0.094811	0.107527	0.000076	0.002852
117	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
118	AP	Acct 881 - Rents	EXP_881	1.000000	0.584197	0.110924	0.295687	0.000267	0.008924
119	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.717567	0.125751	0.152015	0.000213	0.004454
120	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.599159	0.115801	0.275082	0.000168	0.009791
121	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
122	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.599170	0.115805	0.275067	0.000168	0.009791
123	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	0.823837	0.117680	0.057701	0.000094	0.000688
124	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.666502	0.231154	0.102341	0.000000	0.000003
125	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.030466	0.006527	0.008231	0.954537	0.000239
126	AP								
127	AP	Distr Oper Exp	DISTEXPO	1.000000	0.794734	0.094811	0.107527	0.000076	0.002852
128	AP	Distr Maint Exp	DISTEXPM	1.000000	0.665820	0.142636	0.179886	0.006439	0.005219
129	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.814948	0.122277	0.055212	0.000030	0.007533
130	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
131	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.854621	0.083369	0.044649	0.000032	0.017329
132	AP	Sales Expense	SALESEXP	1.000000	0.793082	0.146292	0.060382	0.000026	0.000218

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.780082	0.098566	0.112812	0.000868	0.007671
134	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.753147	0.104399	0.132499	0.001113	0.008841
135	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.753571	0.108266	0.126789	0.001272	0.010102
136	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.559348	0.156032	0.268856	0.001901	0.013863
137	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.856822	0.081210	0.044062	0.000033	0.017872
138	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.732536	0.123339	0.138833	0.000328	0.004965
139	AP								
140	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.720665	0.123931	0.150398	0.000209	0.004797
141	AP								
142	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.718709	0.126985	0.149695	0.000256	0.004354
143	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.850368	0.071136	0.071260	0.000521	0.006716
144	AP								
145	AP	**Labor Expense Related**							
146	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.901074	0.045579	0.051949	0.000037	0.001360
147	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.659426	0.155310	0.175838	0.004660	0.004765
148	AP	Total Labor	LABOR	1.000000	0.850368	0.071136	0.071260	0.000521	0.006716
149	AP								
150	AP	**REVENUES AND BILLING DETERMINANTS**							
151	AP								
152	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.715785	0.126756	0.151656	0.000404	0.005399
153	AP								
154	AP	Residential Service Gas	REVRSG	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
155	AP	General Service Gas	REVGSG	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
156	AP	Large Volume Service Gas	REVLVG	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
157	AP	Street Light Gas	REVSLG	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
158	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
159	AP								
160	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.715785	0.126756	0.151656	0.000404	0.005399
161	AP								
162	AP	**PRESENT REVENUES FROM SALES INPUT**							
163	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Sales of Gas Revenues - Rates		1.000000	0.734224	0.117784	0.136445	0.000397	0.011149
165	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	991,282,164	991,282,164	0	0	0	0
6	ADA	General Service Gas	REVGSG	175,543,177	0	175,543,177	0	0	0
7	ADA	Large Volume Service Gas	REVLVG	210,026,237	0	0	210,026,237	0	0
8	ADA	Street Light Gas	REVSLG	559,485	0	0	0	559,485	0
9	ADA	Firm Transportation Gas Service	REVTSGF	7,477,232	0	0	0	0	7,477,232
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,384,328,810	991,282,164	175,543,177	210,026,237	0	7,477,232
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.716074	0.126807	0.151717	0.0	0.005401
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	175,543,177	0	175,543,177	0	0	0
20	ADA	Large Volume Service Gas	REVLVG	210,026,237	0	0	210,026,237	0	0
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	385,569,414	0	175,543,177	210,026,237	0	0
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.0	0.455283	0.544717	0.0	0.0
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	RSG	GSG	LVG	SLG	TSG Firm
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	----------							
5	RRW	RATE BASE		8,668,832,235	6,226,391,124	1,104,437,503	1,298,370,502	2,253,286	37,379,820
6	RRW	NET OPER INC (PRESENT RATES)		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
10	RRW	REVENUE PRES RATES $/THERM		$0.5330	$0.6531	$0.6091	$0.2734	$0.8053	$0.3225
11	RRW	REVENUE REQUIRED - $/MO/CUST		$60.93	$47.78	$100.54	$883.55	$2,913.99	$19,471.96
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	----------							
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		639,759,819	459,507,665	81,507,488	95,819,743	166,293	2,758,631
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,384,888,295	991,282,164	175,543,177	210,026,237	559,485	7,477,232
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	1,517,910,828	288,213,545	768,279,951	694,743	23,186,772
22	RRW	SALES REV REQUIRED $/THERM		$0.5330	$0.6531	$0.6091	$0.2734	$0.8053	$0.3225
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	S	**SUMMARY OF RESULTS**							
2	S	**DEVELOPMENT OF RETURN**							
3	S								
4	S	**RATE BASE**							
5	S	Plant in Service							
6	S	Production Plant 304-320	CALCULATED	52,043,670	0	52,043,670	0	0	0
7	S	Storage Plant 360-363	CALCULATED	19,575,233	0	19,575,233	0	0	0
8	S	Transmission Plant 365-371	CALCULATED	103,544,395	0	103,544,395	0	0	0
9	S	Distribution Plant							
10	S	Land & Structures 374-375	CALCULATED	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
11	S	Mains 376	CALCULATED	3,775,184,891	0	3,775,184,891	0	0	0
12	S	Compressor Station Equipment 377	CALCULATED	0	0	0	0	0	0
13	S	Meas & Regulating Station Equip 378-379	CALCULATED	285,986,290	0	285,986,290	0	0	0
14	S	Services 380	CALCULATED	5,447,179,699	5,447,179,699	0	0	0	0
15	S	Meters 381	CALCULATED	477,048,047	0	0	0	0	477,048,047
16	S	Meter Installations 382	CALCULATED	52,631,537	0	0	0	0	52,631,537
17	S	House Regulators & Install 383-384	CALCULATED	151,182,537	151,182,537	0	0	0	0
18	S	Industrial Meas & Reg Station Equip 385	CALCULATED	145,614,455	72,807,227	0	0	0	72,807,227
19	S	Other Property on Cust Premises 386	CALCULATED	0	0	0	0	0	0
20	S	Other Equipment (Street Lighting) 387	CALCULATED	1,521,717	509,787	0	1,011,930	0	0
21	S	Asset Retirement Obligation 388	CALCULATED	65,215,073	0	65,215,073	0	0	0
22	S	Total Distribution Plant	CALCULATED	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
23	S	General Plant E389-E399	CALCULATED	200,812,197	116,163,890	84,514,137	20,726	0	113,444
24	S	Common Plant C389-C399	CALCULATED	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
25	S	Intangible Plant E301-E303, E399, C303-C390	CALCULATED	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
26	S	Total Plant in Service	CALCULATED	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
27	S								
28	S	Less: Reserve for Depreciation and Amorization	CALCULATED	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
29	S								
30	S	Plus: Rate Base Additions							
31	S	Working Capital	CALCULATED	664,819,310	328,419,825	242,421,753	143,717	37,280,955	56,553,060
32	S	Capital Stimulas Adjust (Pro Forma #13)	CALCULATED	0	0	0	0	0	0
33	S	Capital Lease Plt & Reserve Deduct	CALCULATED	96,280	14,358	15,405	3	54,332	12,183
34	S	Other Rate Base Additions		1,724,917,916	941,492,892	682,274,946	171,705	570,540	100,407,833
35	S	Plus: Rate Base Deductions							
36	S	Customer Advances	CALCULATED	-24,945,102	-14,734,362	-10,210,740	0	0	0
37	S	Unbilled Revenue	CALCULATED	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
38	S	Deferred Income Taxes and Credits	CALCULATED	-1,714,531,256	-912,227,616	-694,061,202	-162,618	-10,914,018	-97,165,802
39	S								
40	S	Other Rate Base Deductions							
41	S	TOTAL RATE BASE		8,668,832,235	4,773,814,938	3,281,363,918	1,161,960	58,835,070	553,656,348
42	S								
43	S								
44	S	**SUMMARY OF RESULTS**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	S	**DEVELOPMENT OF RETURN**							
46	S								
47	S	**RATE BASE**	CALCULATED	8,668,832,235	4,773,814,938	3,281,363,918	1,161,960	58,835,070	553,656,348
48	S								
49	S	**OPERATING REVENUES**							
50	S	Rate Revenues from Customers	CALCULATED	1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
51	S	Other Operating Revenues	CALCULATED	67,687,036	9,757,504	55,176,319	5,405	1,123,777	1,624,031
52	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
53	S	Less: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
54	S	TOTAL OPERATING REVENUES		1,452,575,331	692,340,976	567,960,291	403,179	80,960,814	110,910,071
55	S								
56	S	**OPERATING EXPENSES**							
57	S	Operation and Maintenance Expense							
58	S	Gas Production and Supply Expense	CALCULATED	31,906,945	0	31,906,945	0	0	0
59	S	Storage Expense	CALCULATED	2,714,605	0	2,714,605	0	0	0
60	S	Transmission Expense	CALCULATED	2,593,507	0	2,593,507	0	0	0
61	S	Distribution Expense	CALCULATED	102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
62	S	Customer Accounts Expense	CALCULATED	98,759,541	12,841,753	12,359,214	0	58,493,025	15,065,550
63	S	Customer Service & Information Expense	CALCULATED	4,034,218	0	2,596,868	0	1,437,350	0
64	S	Sales Expense	CALCULATED	88,423	0	88,423	0	0	0
65	S	Administrative and General Expense	CALCULATED	38,752,071	7,065,455	12,641,034	66,361	12,596,907	6,382,313
66	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	46,315,172	122,801,736	265,586	72,527,282	39,812,932
67	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
68	S	Amortization Expense	CALCULATED	2,351,634	0	1,210,181	0	909,279	232,173
69	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,234,596	-11,466,364	-6,462	-2,592,427	-2,180,874
70	S	Proforma Expense Adjustments	CALCULATED	105,999,447	46,067,751	45,308,541	19,592	6,875,966	7,727,598
71	S	State Income Taxes	CALCULATED	75,668,323	41,428,955	28,813,943	9,988	601,577	4,813,860
72	S	Federal Income Taxes	CALCULATED	139,157,389	76,520,768	52,565,939	19,165	1,046,011	9,005,505
73	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,751,285	6,224,982	-9,746	-6,466,542	-794,464
74	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
75	S	Investment Tax Credit Adjustement (Net)	CALCULATED	0	0	0	0	0	0
76	S	TOTAL OPERATING EXPENSES		812,815,512	340,033,434	325,795,634	317,426	76,618,786	70,050,232
77	S								
78	S	**OPERATING INCOME (RETURN)**		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839
79	S	Plus Operating Income Adjustment	CALCULATED						
80	S	TOTAL NET OPERATING INCOME		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839
81	S								
82	S	**RATE OF RETURN ON RATE BASE (PRESENT)**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
83	S	**INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00
84	S								
85	S								
86	S	**EQUALIZED RETURN AT PROPOSED ROR**							
87	S	**DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)**							
88	S								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	S	**RATE BASE**	CALCULATED	8,668,832,235	4,773,814,938	3,281,363,918	1,161,960	58,835,070	553,656,348
90	S								
91	S	**RATE OF RETURN**		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
92	S								
93	S	**RETURN (RATE BASE * 7.40% ROR)**		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839
94	S								
95	S	**PLUS:**							
96	S	**OPERATING EXPENSES**							
97	S	Total Operation and Maintenance Expense	CALCULATED	281,722,708	46,315,172	122,801,736	265,586	72,527,282	39,812,932
98	S	Depreciation Expense	CALCULATED	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
99	S	Amortization Expense	CALCULATED	2,351,634	0	1,210,181	0	909,279	232,173
100	S	Taxes Other Than Income Taxes	CALCULATED	-24,480,722	-8,234,596	-11,466,364	-6,462	-2,592,427	-2,180,874
101	S	Proforma Expense Adjustments	CALCULATED	105,999,447	46,067,751	45,308,541	19,592	6,875,966	7,727,598
102	S	Income Taxes	CALCULATED	214,825,712	117,949,724	81,379,882	29,153	1,647,588	13,819,365
103	S	Provision for Deferred Income Taxes	CALCULATED	28,705,516	29,751,285	6,224,982	-9,746	-6,466,542	-794,464
104	S	Income Taxes Deferred in Prior Years	CALCULATED	0	0	0	0	0	0
105	S	Investment Tax Credit Adjustement (Net)	CALCULATED						
106	S	**TOTAL OPERATING EXPENSES**		812,815,512	340,033,434	325,795,634	317,426	76,618,786	70,050,232
107	S								
108	S	**EQUALS TOTAL COST OF SERVICE**		1,452,575,331	692,340,976	567,960,291	403,179	80,960,814	110,910,071
109	S								
110	S	**LESS:**							
111	S	Other Operating Revenues	CALCULATED	67,687,036	9,757,504	55,176,319	5,405	1,123,777	1,624,031
112	S	Revenues from Other Sources	CALCULATED	0	0	0	0	0	0
113	S	Plus: Provisions for Rate Refunds	CALCULATED	0	0	0	0	0	0
114	S	**EQUALS:**							
115	S	**BASE RATE SALES @ EQUALIZED ROR 7.40%**		1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
116	S								
117	S	**TOTAL COST OF SERVICE INCREASE/DECREASE**		0	0	0	0	0	0
118	S	**REVENUE INCREASE TO RETAIL REVENUES (%)**		0.00	0.00	0.00	0.00	0.00	0.00

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBP	**DEVELOPMENT OF RATE BASE**							
2	RBP								
3	RBP	**GAS PLANT IN SERVICE**							
4	RBP								
5	RBP	INTANGIBLE PLANT - G301-G303							
6	RBP	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
7	RBP	Choice Progect	not_used	0	0	0	0	0	0
8	RBP	GSMIS - meter related	not_used	0	0	0	0	0	0
9	RBP	- regulator related	not_used	0	0	0	0	0	0
10	RBP	- appliance safety related	not_used	0	0	0	0	0	0
11	RBP	- Comp Svs related	not_used	0	0	0	0	0	0
12	RBP	- Cust Svs related	not_used	0	0	0	0	0	0
13	RBP	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0
14	RBP								
15	RBP	C303 - INTANGIBLE PLANT - CUST SERVICE							
16	RBP	Customer Service	CUSTSVSX	16,301,302	0	1,127,751	0	12,410,339	2,763,212
17	RBP	Measurement	MRCOST_07	0	0	0	0	0	0
18	RBP	Not Used	not_used	0	0	0	0	0	0
19	RBP	G399.1 Asset Retirement Costs of General Plt	GENPLT	490,552	283,770	206,454	51	0	277
20	RBP	Not Used	not_used	0	0	0	0	0	0
21	RBP	TOTAL ACCOUNTS C303-C390.4,G399		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
22	RBP								
23	RBP	TOTAL INTANGIBLE PLANT		16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
24	RBP								
25	RBP	PRODUCTION PLANT							
26	RBP	G304-G320 - All Land & Equipment	BALANCE_04	52,043,670	0	52,043,670	0	0	0
27	RBP	Not Used	not_used	0	0	0	0	0	0
28	RBP	TOTAL PRODUCTION PLANT		52,043,670	0	52,043,670	0	0	0
29	RBP								
30	RBP	STORAGE PLANT							
31	RBP	G360-G363 - All Land & Equipment	BALANCE_04	19,575,233	0	19,575,233	0	0	0
32	RBP	Not Used	not_used	0	0	0	0	0	0
33	RBP	TOTAL STORAGE PLANT		19,575,233	0	19,575,233	0	0	0
34	RBP								
35	RBP	TRANSMISSION PLANT							
36	RBP	G365 Land & Land Rights	AVGPEAK_04	5,421,128	0	5,421,128	0	0	0
37	RBP	G366 Structures & Improvements	AVGPEAK_04	0	0	0	0	0	0
38	RBP	G367 Mains	AVGPEAK_04	93,786,847	0	93,786,847	0	0	0
39	RBP	G369 Meas. & Reg. Station Equipment	AVGPEAK_04	4,336,420		4,336,420			
40	RBP	TOTAL TRANSMISSION PLANT		103,544,395	0	103,544,395	0	0	0
41	RBP								
42	RBP								
43	RBP								
44	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBP								
46	RBP	DISTRIBUTION PLANT							
47	RBP	G374-G375 Land & Structures							
48	RBP	General	DISTPLT	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
49	RBP	Not Used	not_used	0	0	0	0	0	0
50	RBP	Total Accounts G374-G375		96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
51	RBP								
52	RBP	G376 Mains							
53	RBP	Firm Allocation	AVGPEAK_04	3,772,391,917	0	3,772,391,917	0	0	0
54	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	2,792,974	0	2,792,974	0	0	0
55	RBP	Not Used	not_used	0	0	0	0	0	0
56	RBP	Total Account G376		3,775,184,891	0	3,775,184,891	0	0	0
57	RBP								
58	RBP	G377 Compressor Station Equip	DISTPLTXMTR	0	0	0	0	0	0
59	RBP								
60	RBP	G378-G379 Meas & Regulatory Equipment							
61	RBP	Firm Investment	AVGPEAK_04	285,986,290	0	285,986,290	0	0	0
62	RBP	Not Used	not_used	0	0	0	0	0	0
63	RBP	Total Account G378-G379		285,986,290	0	285,986,290	0	0	0
64	RBP								
65	RBP	G380 Services							
66	RBP	Firm Allocation	SERVICES_03	5,442,013,091	5,442,013,091	0	0	0	0
67	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	5,166,608	5,166,608	0	0	0	0
68	RBP	Not Used	not_used	0	0	0	0	0	0
69	RBP	Total Account G380		5,447,179,699	5,447,179,699	0	0	0	0
70	RBP								
71	RBP	G381 Meters							
72	RBP	Firm Allocation	SMMETERS_07	477,045,042	0	0	0	0	477,045,042
73	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	3,005	0	0	0	0	3,005
74	RBP	Not Used	not_used	0	0	0	0	0	0
75	RBP	Total Account G381		477,048,047	0	0	0	0	477,048,047
76	RBP								
77	RBP	G382 Meter Installations							
78	RBP	Firm Allocation	MTRINSTAL_07	52,630,927	0	0	0	0	52,630,927
79	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	609	0	0	0	0	609
80	RBP	Not Used	not_used	0	0	0	0	0	0
81	RBP	Total Account G382		52,631,537	0	0	0	0	52,631,537
82	RBP								
83	RBP								
84	RBP								
85	RBP								
86	RBP								
87	RBP								
88	RBP	**GAS PLANT IN SERVICE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBP								
90	RBP	DISTRIBUTION PLANT CONTINUED							
91	RBP								
92	RBP	G383 House Regulators & Installation							
93	RBP	Firm Allocation - Regulators - G383	HOUSEREG_03	38,488,025	38,488,025	0	0	0	0
94	RBP	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	11,098	11,098	0	0	0	0
95	RBP	Not Used	not_used	0	0	0	0	0	0
96	RBP	Total Account G383		38,499,123	38,499,123	0	0	0	0
97	RBP								
98	RBP	G384 House Regulators & Installation		0	0	0	0	0	0
99	RBP	Firm Allocation - Installation - G384	HSEREGINST_03	112,681,544	112,681,544	0	0	0	0
100	RBP	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,870	1,870	0	0	0	0
101	RBP	Total Account G384		112,683,414	112,683,414	0	0	0	0
102	RBP	G385 Industrial Meas and Regul Station Equip							
103	RBP	Firm Allocation - Regulators	LRGREG_03	71,912,204	71,912,204	0	0	0	0
104	RBP	Firm Allocation - Meters	LRGMTR_07	71,912,204	0	0	0	0	71,912,204
105	RBP	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	895,023	895,023	0	0	0	0
106	RBP	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	895,023	0	0	0	0	895,023
107	RBP	Not Used	not_used	0	0	0	0	0	0
108	RBP	Total Account G385		145,614,455	72,807,227	0	0	0	72,807,227
109	RBP								
110	RBP	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
111	RBP								
112	RBP	G387-Other Equipment							
113	RBP	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	1,011,930	0	0	1,011,930	0	0
114	RBP	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	509,787	509,787	0	0	0	0
115	RBP	Total Accounts G387		1,521,717	509,787	0	1,011,930	0	0
116	RBP								
117	RBP	G388 - Asset Retirement Obligations	PLT_376	65,215,073	0	65,215,073	0	0	0
118	RBP								
119	RBP	TOTAL DISTRIBUTION PLANT		10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
120	RBP								
121	RBP								
122	RBP								
123	RBP								
124	RBP								
125	RBP								
126	RBP								
127	RBP								
128	RBP								
129	RBP								
130	RBP								
131	RBP								
132	RBP								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	RBP								
134	RBP								
135	RBP	**GAS PLANT IN SERVICE CONTINUED**							
136	RBP								
137	RBP	GENERAL AND COMMON PLANT							
138	RBP	E390-E398 GENERAL PLANT							
139	RBP	Meter Related	METERPLT	0	0	0	0	0	0
140	RBP	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
141	RBP	Appliance Safety Related	CINST_04	0	0	0	0	0	0
142	RBP	Distribution Delivery	DISTPLTXMTR	200,812,197	116,163,890	84,514,137	20,726	0	113,444
143	RBP	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
144	RBP	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
145	RBP	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
146	RBP	Total Accounts E390-E398		200,812,197	116,163,890	84,514,137	20,726	0	113,444
147	RBP								
148	RBP	C389-C399 COMMON PLANT							
149	RBP	ASB Work Related	CINST_04	0	0	0	0	0	0
150	RBP	Meter Plant Related	METERPLT	0	0	0	0	0	0
151	RBP	Not Used	not_used	0	0	0	0	0	0
152	RBP	Customer Service Related	CUSTSVSX	75,768,117	0	5,241,765	0	57,683,000	12,843,352
153	RBP	Distribution Delivery Related	DISTPLTXMTR	25,073,523	14,504,288	10,552,482	2,588	0	14,165
154	RBP	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
155	RBP	Unassigned	TOTPLT	1,393,316	742,218	563,006	132	8,885	79,075
156	RBP	Total Accounts C389-C399		102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
157	RBP								
158	RBP	TOTAL GENERAL AND COMMON PLANT		303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
159	RBP								
160	RBP								
161	RBP	**TOTAL GAS PLANT IN SERVICE (101)**		10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBD	**LESS: DEPRECIATION RESERVE & AMORT**							
2	RBD								
3	RBD	G301-G303 - INTANGILE PLANT - RESERVE							
4	RBD	General - AWMS & Misc.	TOTPLT	0	0	0	0	0	0
5	RBD	Choice Progect	not_used	0	0	0	0	0	0
6	RBD	GSMIS - meter related	not_used	0	0	0	0	0	0
7	RBD	- regulator related	not_used	0	0	0	0	0	0
8	RBD	- appliance safety related	not_used	0	0	0	0	0	0
9	RBD	- Comp Svs related	not_used	0	0	0	0	0	0
10	RBD	- Cust Svs related	not_used	0	0	0	0	0	0
11	RBD	Total Accounts E301-E303 Reserve		0	0	0	0	0	0
12	RBD								
13	RBD	C303 - INTANGIBLE PLANT - CUST SERVICE							
14	RBD	Customer Service	CUSTSVSX	9,821,603	0	679,475	0	7,477,281	1,664,847
15	RBD	Measurement	MRCOST_07	0	0	0	0	0	0
16	RBD	Not Used	not_used	0	0	0	0	0	0
17	RBD	G399.1 Asset Retirement Costs of General Plt	GENPLT	0	0	0	0	0	0
18	RBD	Not Used	not_used	0	0	0	0	0	0
19	RBD	TOTAL ACCOUNTS C303-C390.4,G399		9,821,603	0	679,475	0	7,477,281	1,664,847
20	RBD								
21	RBD	TOTAL INTANGIBLE PLANT		9,821,603	0	679,475	0	7,477,281	1,664,847
22	RBD								
23	RBD	PRODUCTION PLANT G304-G320 RESERVE	BALANCE_04	56,077,402	0	56,077,402	0	0	0
24	RBD								
25	RBD	STORAGE PLANT G360-G363 RESERVE	BALANCE_04	9,476,790	0	9,476,790	0	0	0
26	RBD								
27	RBD	TRANSMISSION PLANT G365-G369 RESERVE	TRANPLT	50,246,121	0	50,246,121	0	0	0
28	RBD								
29	RBD	DISTRIBUTION PLANT RESERVE							
30	RBD	G374-G375 Land & Structures Reserve	PLT_3745	432,406	235,779	171,539	42	0	25,046
31	RBD								
32	RBD	G376 Mains Reserve							
33	RBD	Firm Allocation	AVGPEAK_04	1,017,890,245	0	1,017,890,245	0	0	0
34	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_04	759,994	0	759,994	0	0	0
35	RBD	Not Used	not_used	0	0	0	0	0	0
36	RBD	Total Account G376		1,018,650,239	0	1,018,650,239	0	0	0
37	RBD								
38	RBD	G377 Compressor Station Equip Reserve	DISTPLTXMTR						
39	RBD								
40	RBD	G378-G379 Meas & Regulatory Equip Reserve							
41	RBD	Firm Investment	AVGPEAK_04	93,669,010	0	93,669,010	0	0	0
42	RBD	Not Used	not_used	0	0	0	0	0	0
43	RBD	Total Account G378-G379		93,669,010	0	93,669,010	0	0	0
44	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	RBD								
46	RBD	**DISTRIBUTION PLANT CONTINUED**							
47	RBD								
48	RBD	G380 Services Reserve							
49	RBD	Firm Allocation	SERVICESR_03	1,126,944,013	1,126,944,013	0	0	0	0
50	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	2,349,910	2,349,910	0	0	0	0
51	RBD	Not Used	not_used	0	0	0	0	0	0
52	RBD	Total Account G380		1,129,293,923	1,129,293,923	0	0	0	0
53	RBD								
54	RBD	G381 Meters Reserve							
55	RBD	Firm Allocation	SMMETERSR_07	61,006,069	0	0	0	0	61,006,069
56	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	1,948	0	0	0	0	1,948
57	RBD	Not Used	not_used	0	0	0	0	0	0
58	RBD	Total Account G381		61,008,018	0	0	0	0	61,008,018
59	RBD								
60	RBD	G382 Meter Installations Reserve							
61	RBD	Firm Allocation	MTRINSTALR_07	33,652,945	0	0	0	0	33,652,945
62	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_07	279	0	0	0	0	279
63	RBD	Not Used	not_used	0	0	0	0	0	0
64	RBD	Total Account G382		33,653,224	0	0	0	0	33,653,224
65	RBD								
66	RBD	G383 House Regulators & Installation Reserve							
67	RBD	Firm Allocation - Regulators - G383	HOUSEREGR_03	25,030,964	25,030,964	0	0	0	0
68	RBD	CIG, TSG-NF & CSG Redistribution	TRANSPORT_03	4,827	4,827	0	0	0	0
69	RBD	Not Used	not_used	0	0	0	0	0	0
70	RBD	Total Account G383		25,035,791	25,035,791	0	0	0	0
71	RBD								
72	RBD	G384 House Regulators & Installation Reserve		0	0	0	0	0	0
73	RBD	Firm Allocation - Installation - G384	HSEREGINSTR_03	58,406,745	58,406,745	0	0	0	0
74	RBD	G384 CIG. TSG-NF & CSG Redistribution	TRANSPORT_03	1,006	1,006	0	0	0	0
75	RBD	Total Account G384		58,407,752	58,407,752	0	0	0	0
76	RBD	G385 Industrial Meas and Regul Sta Equip Reserve							
77	RBD	Firm Allocation - Regulators	LRGREGR_03	12,236,618	12,236,618	0	0	0	0
78	RBD	Firm Allocation - Meters	LRGMTRR_07	12,236,618	0	0	0	0	12,236,618
79	RBD	CIG, TSG-NF & CSG Redistribution - Regulators	TRANSPORT_03	295,977	295,977	0	0	0	0
80	RBD	CIG, TSG-NF & CSG Redistribution - Meters	TRANSPORT_07	295,977	0	0	0	0	295,977
81	RBD	Not Used	not_used	0	0	0	0	0	0
82	RBD	Total Account G385		25,065,190	12,532,595	0	0	0	12,532,595
83	RBD								
84	RBD	G386 Other Prop on Cust Prem	TRANSPORT_04	0	0	0	0	0	0
85	RBD	G387.1 Other Eqmt - Street Ltg Posts	DIRSLG_05	0	0	0	0	0	0
86	RBD	G387.2 Other Eqmt - Street Ltg Services	DIRSLG_03	0	0	0	0	0	0
87	RBD								
88	RBD	TOTAL DISTRIBUTION PLANT RESERVE		2,445,215,554	1,225,505,840	1,112,490,788	42	0	107,218,883

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	RBD								
90	RBD	**DEPRECIATION RESERVE & AMORT CONTINUED**							
91	RBD								
92	RBD	GENERAL AND COMMON PLANT RESERVE							
93	RBD								
94	RBD	E390-E398 GENERAL PLANT - RESERVE							
95	RBD	Meter Related	METERPLT	0	0	0	0	0	0
96	RBD	Regulator Plant Related	PLT_3834	0	0	0	0	0	0
97	RBD	Appliance Safety Related	CINST_04	0	0	0	0	0	0
98	RBD	Distribution Delivery	DISTPLTXMTR	94,949,830	54,925,656	39,960,735	9,800	0	53,640
99	RBD	Competitive Service	COMPSVSWK_04	0	0	0	0	0	0
100	RBD	SONP/RNP Related	CUSTAVG_04	0	0	0	0	0	0
101	RBD	Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
102	RBD	Total Accounts E390-E398		94,949,830	54,925,656	39,960,735	9,800	0	53,640
103	RBD								
104	RBD	C389-C399 COMMON PLANT							
105	RBD	ASB Work Related	CINST_04	0	0	0	0	0	0
106	RBD	Not Used	not_used	0	0	0	0	0	0
107	RBD	Customer Service Related	CUSTSVSX	38,276,434	0	2,648,028	0	29,140,219	6,488,187
108	RBD	Distribution Delivery Related	DISTPLTXMTR	13,134,595	7,597,973	5,527,846	1,356	0	7,420
109	RBD	Service & Support Related	UTILWORK_04	0	0	0	0	0	0
110	RBD	Unassigned	TOTPLT	1,273,650	678,472	514,652	121	8,122	72,284
111	RBD	Total Accounts C389-C399 Reserve		52,684,679	8,276,445	8,690,526	1,477	29,148,341	6,567,890
112	RBD								
113	RBD	**TOTAL DEPRECIATION RESERVE & AMORT.**		2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
114	RBD								
115	RBD								
116	RBD	**NET GAS PLANT IN SERVICE**		8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
117	RBD	Meter Plant Related	METERPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RBO	**ADDITIONS AND DEDUCTIONS TO RATE BASE**							
2	RBO								
3	RBO	**PLUS: ADDITIONS TO RATE BASE**							
4	RBO								
5	RBO	Working Capital							
6	RBO	Materials and Supplies Excl Fuel Stock	PSTDPLT	59,382,049	31,847,963	24,145,283	5,682	0	3,383,121
7	RBO	Fuel Stock & Fuel Stock Expense	not_used	0	0	0	0	0	0
8	RBO	Gas Stored Underground	not_used	0	0	0	0	0	0
9	RBO	Cash (lead/lag)	EXPENDITURES	605,321,561	296,515,187	218,234,756	138,009	37,273,830	53,159,778
10	RBO	Prepayments/Working Funds	EXPENDITURES	115,700	56,675	41,713	26	7,124	10,161
11	RBO	Total Working Capital		664,819,310	328,419,825	242,421,753	143,717	37,280,955	56,553,060
12	RBO	CEF-EC Adjustment	not_used	0	0	0	0	0	0
13	RBO	CEF-EV Adjustment	not_used	0	0	0	0	0	0
14	RBO	Net Plant Adds - Distribution	DISTPLT	1,583,894,314	863,652,841	628,343,927	154,091	0	91,743,454
15	RBO	Capital Stimulas Adjust	DISTPLT	0	0	0	0	0	0
16	RBO	Capital Lease Plant & Reserve Deduction	COMPLT	96,280	14,358	15,405	3	54,332	12,183
17	RBO	Net Plant Adds - General & Other	TOTPLTNET	141,023,603	77,840,051	53,931,020	17,614	570,540	8,664,379
18	RBO	TOTAL ADDITIONS TO RATE BASE		2,389,833,506	1,269,927,075	924,712,104	315,425	37,905,826	156,973,077
19	RBO								
20	RBO	**PLUS: DEDUCTIONS TO RATE BASE**							
21	RBO								
22	RBO	Customer Advances for Construction	MAIN_SERV	-24,945,102	-14,734,362	-10,210,740	0	0	0
23	RBO	IAP Adjustment	not_used	0	0	0	0	0	0
24	RBO	GSMP II EXT Adjustment	TOTPLT	-256,132,009	-136,441,189	-103,496,869	-24,344	-1,633,339	-14,536,269
25	RBO	Deferred Income Taxes and Credits							
26	RBO	ADIT Test/Post year	TOTPLT	0	0	0	0	0	0
27	RBO	Liberalized Depreciation	TOTPLT	35,377,684	18,845,647	14,295,283	3,362	225,601	2,007,791
28	RBO	Liberalized Depreciation - Production	BALANCE_04	-1,955,963	0	-1,955,963	0	0	0
29	RBO	Cost of Removal	TOTPLT	9,569,770	5,097,804	3,866,917	910	61,026	543,114
30	RBO	3% Investment Tax Credit	DISTPLT	0	0	0	0	0	0
31	RBO	Computer Software	TOTPLT	0	0	0	0	0	0
32	RBO	Capitalized Interest	TOTPLTNET	-160,793	-88,752	-61,491	-20	-651	-9,879
33	RBO	NJ Corporate Business Tax	STATEINCTAX	4,194,912	2,296,744	1,597,392	554	33,350	266,871
34	RBO	Defrd Tax & Consolidated Tax Adjustment	TOTPLT	-1,761,556,867	-938,379,059	-711,803,340	-167,424	-11,233,345	-99,973,699
35	RBO	Total Deferred Income Taxes and Credits		-1,714,531,256	-912,227,616	-694,061,202	-162,618	-10,914,018	-97,165,802
36	RBO								
37	RBO	TOTAL DEDUCTIONS TO RATE BASE		-1,995,608,367	-1,063,403,167	-807,768,811	-186,962	-12,547,357	-111,702,071
38	RBO								
39	RBO								
40	RBO	**TOTAL RATE BASE**		8,668,832,235	4,773,814,938	3,281,363,918	1,161,960	58,835,070	553,656,348

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	REV	**OPERATING REVENUES**							
2	REV								
3	REV	**SALES REVENUES**							
4	REV	BASE RATE SALES @ EQUALIZED ROR 7.40%		1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
5	REV	Revenue Requirement - Other #1	not_used	0	0	0	0	0	0
6	REV	Revenue Requirement - Other #2	not_used	0	0	0	0	0	0
7	REV	TOTAL SALES OF GAS		1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
8	REV								
9	REV	**OTHER OPERATING REVENUES**							
10	REV	G487-Forfeited Discounts	REVLATEP	1,447,215	475,752	795,939	0	38,390	137,134
11	REV	G488-Miscellaneous Service Revenues	COMPSVSWK_04	40,880,111	0	40,880,111	0	0	0
12	REV	G489-Revenues from Transmission from Others	not_used	0	0	0	0	0	0
13	REV	G493-Rent from Gas Property	TOTPLT	0	0	0	0	0	0
14	REV	G495-Other Gas Revenues							
15	REV	Miscellaneous Gas Revenues	TOTREV	19,473,704	9,281,751	7,614,263	5,405	1,085,387	1,486,897
16	REV	Peak Shaving Revenues	BALANCE_04	5,886,006	0	5,886,006	0	0	0
17	REV	Not Used	not_used	0	0	0	0	0	0
18	REV	Not Used	not_used	0	0	0	0	0	0
19	REV	TOTAL OTHER OPERATING REV		67,687,036	9,757,504	55,176,319	5,405	1,123,777	1,624,031
20	REV								
21	REV	**OTHER REVENUE SOURCES**							
22	REV	Not Used	not_used	0	0	0	0	0	0
23	REV	Not Used	not_used	0	0	0	0	0	0
24	REV	TOTAL OTHER REVENUE SOURCES		0	0	0	0	0	0
25	REV								
26	REV	LESS: E496 Provision for Rate Refunds	TOTREV	0	0	0	0	0	0
27	REV								
28	REV	**TOTAL OPERATING REVENUES**		1,452,575,331	692,340,976	567,960,291	403,179	80,960,814	110,910,071

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	E	**OPERATION & MAINTENANCE EXPENSE**							
2	E								
3	E	MANUFACTURED GAS PRODUCTION EXPENSE							
4	E	G710-G718 Production Expenses Incl Labor	BALANCE_04	281,982	0	281,982	0	0	0
5	E	G722-G736 Gas Raw Materials	BALANCE_04	29,792,635	0	29,792,635	0	0	0
6	E	G739-G745 Operation & Maintenance Exp	BALANCE_04	1,832,256	0	1,832,256	0	0	0
7	E	Not Used	not_used	0	0	0	0	0	0
8	E	TOTAL MANUFACTURED GAS PRODUCTION EXP		31,906,873	0	31,906,873	0	0	0
9	E								
10	E	OTHER GAS SUPPLY EXPENSE							
11	E	G801 Natural Gas Field Line Purchases	not_used	0	0	0	0	0	0
12	E	G804 Natural Gas City Gate Purchases	not_used	0	0	0	0	0	0
13	E	G805 Other Gas Purchases	not_used	0	0	0	0	0	0
14	E	G808.1,.2 GasInject & W/D from Storage	not_used	0	0	0	0	0	0
15	E	G812 Gas Used for Other Util Oper	not_used	0	0	0	0	0	0
16	E	G813 Other Gas Supply Expenses							
17	E	Supply Related	not_used	0	0	0	0	0	0
18	E	Distribution Related	TRANSPORT_04	72		72			
19	E	TOTAL OTHER GAS SUPPLY EXPENSE		72		72			
20	E	TOTAL GAS PRODUCTION AND SUPPLY		31,906,945	0	31,906,945	0	0	0
21	E								
22	E	OTHER STORAGE EXPENSE							
23	E	G840-G842 Operation	BALANCE_04	8,906	0	8,906	0	0	0
24	E	G843 Maintenance	BALANCE_04	2,705,699		2,705,699			
25	E	TOTAL OTHER STORAGE EXPENSE		2,714,605	0	2,714,605	0	0	0
26	E								
27	E	TRANSMISSION EXPENSES							
28	E	G850-G867 Transmission Exp	TRANPLT	2,593,507		2,593,507			
29	E	TOTAL TRANSMISSION EXPENSE		2,593,507	0	2,593,507	0	0	0
30	E								
31	E	DISTRIBUTION EXPENSES							
32	E	Operation							
33	E	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
34	E	G871 Load Dispatching	TRANSPORT_04	5,839,316	0	5,839,316	0	0	0
35	E	G872 Compressor Station Labor & Expenses	TRANSPORT_04	0	0	0	0	0	0
36	E	G874 Mains & Services	MAIN_SERV	20,733,577	12,246,734	8,486,843	0	0	0
37	E	G875 Meas & Reg Station - General	PLT_3789	2,497,019	0	2,497,019	0	0	0
38	E	G876 Meas & Reg Station - Industrial	PLT_3789	7,594	0	7,594	0	0	0
39	E	G877 Meas & Reg Station - City Gate	PLT_3789	514,539	0	514,539	0	0	0
40	E	G878 Meter & House Reg	PLT_3814	11,492,061	2,551,763	0	0	0	8,940,298
41	E	G879 Customer Installations							
42	E	- Customer Installations	CINST_04	17,355,157	0	17,355,157	0	0	0
43	E	- Competitive Services by ASB	COMPSVSWK_04	0	0	0	0	0	0
44	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	E								
46	E	G880.0,.1,.2 Other Expenses	DISTEXPO	14,050,188	3,625,445	8,234,483	0	0	2,190,260
47	E	G880.3 Operation of Street Lighting	DIRSLG_05	0	0	0	0	0	0
48	E	G881 Rents	TRANSPORT_04	-1,088,602	0	-1,088,602	0	0	0
49	E	Total Distribution Operation		71,400,849	18,423,942	41,846,349	0	0	11,130,558
50	E								
51	E	DISTRIBUTION EXPENSES CONTINUED							
52	E	Maintenance							
53	E	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
54	E	G886 Structures & Improvements	PLT_3745	8,016,449	4,371,143	3,180,191	780	0	464,334
55	E	G887 Mains	PLT_376	8,706,285	0	8,706,285	0	0	0
56	E	G888 Compressor Station Equip	PLT_377	0	0	0	0	0	0
57	E	G889 Meas & Reg Station - General	PLT_3789	1,007,898	0	1,007,898	0	0	0
58	E	G891 Meas & Reg Station - City Gate	PLT_3789	3,155,564	0	3,155,564	0	0	0
59	E	G892 Services	SERVICES	3,610,466	3,610,466	0	0	0	0
60	E	G893 Meters & House Reg							
61	E	G893.1 - Meters	SMMETERS_07	6,767,990	0	0	0	0	6,767,990
62	E	G893.4 - House Regulators	PLT_3834	0	0	0	0	0	0
63	E	Not Used	not_used	0	0	0	0	0	0
64	E	G894 Maint of Other Equipment							
65	E	G894.0 - Maint of Other Equip	DISTEXPM	9,513	2,413	4,853	60	0	2,187
66	E	G894.1 - Maint of Gas Streetlights	DIRSLG_05	198,384	0	0	198,384	0	0
67	E	Total Distribution Maintenance		31,472,549	7,984,022	16,054,791	199,225		7,234,511
68	E	TOTAL DISTRIBUTION PLANT O&M EXPENSES		102,873,398	26,407,965	57,901,140	199,225	0	18,365,069
69	E								
70	E	TOTAL OPER & MAINT EXP (PROD,STOR, TRAN,& DIST)		140,088,455	26,407,965	95,116,197	199,225	0	18,365,069
71	E								
72	E	CUSTOMER ACCOUNTS EXPENSES							
73	E	G901 Supervision	CUSTACCTS	0	0	0	0	0	0
74	E	G902 Meter Reading							
75	E	- Meter Reading Related	MRCOST_07	12,907,838	0	0	0	0	12,907,838
76	E	- Meter O&M Related	METERPLT	38,249	0	0	0	0	38,249
77	E	G903 Customer Records and Collection							
78	E	- SONP/RNP	CUSTAVG_06	526,534	0	0	0	526,534	0
79	E	- Meter O&M Related	METERPLT	0	0	0	0	0	0
80	E	- Meter Reading Related	MRCOST_07	63,202	0	0	0	0	63,202
81	E	- Billing Related	BILLING_06	16,558,655	0	0	0	16,558,655	0
82	E	- Acct Maint Related	ACCTMAINT_06	26,073,286	0	0	0	26,073,286	0
83	E	- Utility Work Related	UTILWORK_04	2,712,621	0	2,712,621	0	0	0
84	E	- Remaining	BILLING_06	13,832,442	0	0	0	13,832,442	0
85	E	Not used	not_used	0	0	0	0	0	0
86	**E**	**OPERATION & MAINTENANCE EXPENSE CONTINUED**							
87	E								
88	E	G904 Uncollectible Accounts	EXP_904	26,046,715	12,841,753	9,646,594	0	1,502,107	2,056,261

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	E	G905 Misc Customer Accounts	CUSTACCTS	0	0	0	0	0	0
90	E	TOTAL CUSTOMER ACCTS EXPENSE		98,759,541	12,841,753	12,359,214	0	58,493,025	15,065,550
91	E								
92	E	CUSTOMER SERVICE & INFO EXPENSES							
93	E	G907 & 908 - Customer Service & Information							
94	E	- Billing	BILLING_06	37,379	0	0	0	37,379	0
95	E	- Acct Maint related	ACCTMAINT_06	746,413	0	0	0	746,413	0
96	E	- Utility work related	UTILWORK_04	1,684,915	0	1,684,915	0	0	0
97	E	- Remaining	ACCTMAINT_06	0	0	0	0	0	0
98	E	G909 Info & Instr Advertising	TRANSPORT_04	0	0	0	0	0	0
99	E	G910 - Misc Cust Service & Info							
100	E	- Utility work related	UTILWORK_04	911,953	0	911,953	0	0	0
101	E	- Remaining	BILLING_06	653,558				653,558	
102	E	TOTAL CUSTOMER SERVICE & INFO EXPENSES		4,034,218	0	2,596,868	0	1,437,350	0
103	E								
104	E	SALES EXPENSES							
105	E	G912 - Demonstrating and Selling	UTILWORK_04	88,423	0	88,423	0	0	0
106	E	G913 - Advertising	UTILWORK_04	0	0	0	0	0	0
107	E	G916 - Miscellaneous	UTILWORK_04	0	0	0	0	0	0
108	E								
109	E	SALES EXPENSES TOTAL (ACCT 916)		88,423	0	88,423	0	0	0
110	E								
111	E	TOTAL OPER & MAINT EXCL A&G		242,970,637	39,249,718	110,160,702	199,225	59,930,374	33,430,619
112	E								
113	E	ADMINISTRATIVE & GENERAL EXPENSE							
114	E	G920 A&G Salaries	TOMXFUEL904	6,954,680	1,040,344	2,525,173	8,254	2,207,442	1,173,466
115	E	G921 Office Supplies & Exp	TOMXFUEL904	652,569	97,617	236,941	775	207,128	110,108
116	E	G923 Outside Services Employed							
117	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
118	E	- Remaining	TOMXFUEL904	61,043,177	9,131,393	22,164,151	72,451	19,375,338	10,299,845
119	E	G924 Property Insurance	TOTPLT	296,480	157,935	119,801	28	1,891	16,826
120	E	G925 Injuries & Damages	LABOR	15,351,785	1,426,222	8,414,792	7,268	3,520,346	1,983,158
121	E	G926 Employee Pension & Benefits							
122	E	- Gas Peaking Plant Related	BALANCE_04	0	0	0	0	0	0
123	E	- Remaining	LABOR	-60,778,346	-5,646,473	-33,314,505	-28,773	-13,937,193	-7,851,402
124	E	G928 Regulatory Comm Exp	TRANSPORT_04	5,147,284	0	5,147,284	0	0	0
125	E	G929 Duplicate Charges - credit	INTRAREV	764,611	181,417	529,481	0	14,943	38,771
126	E	G930.1 General Advertising Expenses	TRANSPORT_04	1,968,152	0	1,968,152	0	0	0
127	E	G930.2 Misc General Expenses	TRANSPORT_04	3,638,524	0	3,638,524	0	0	0
128	E	G931 Rents	AGEXP	3,713,155	676,999	1,211,242	6,359	1,207,013	611,542
129	E	G932 Maint of General Plant	COMGENPLT	0	0	0	0	0	0
130	E	G935 Other A&G Maint	COMGENPLT	0	0	0	0	0	0
131	E	Not Used	not_used	0	0	0	0	0	0
132	E	TOTAL A&G EXPENSE		38,752,071	7,065,455	12,641,034	66,361	12,596,907	6,382,313

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	E								
134	E	**TOTAL OPERATION & MAINTENANCE EXPENSES**		281,722,708	46,315,172	122,801,736	265,586	72,527,282	39,812,932
135	E	G890 Meas & Reg Station - Industrial	PLT_3789	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	DE	**DEPRECIATION AND AMORTIZATION EXPENSES**							
2	DE								
3	DE	G403 DEPRECIATION EXPENSE							
4	DE	Production Plant	BALANCE_04	1,670	0	1,670	0	0	0
5	DE	Storage Plant	BALANCE_04	114,612	0	114,612	0	0	0
6	DE	Transmission Plant	TRANPLT	1,172,631	0	1,172,631	0	0	0
7	DE	Distribution Plant	DISTPLT	182,874,076	99,716,069	72,547,653	17,791	0	10,592,562
8	DE	General and Common Plant	COMGENPLT	19,528,227	8,468,029	6,500,109	1,511	3,717,640	840,939
9	DE	Not Used	not_used	0	0	0	0	0	0
10	DE	TOTAL DEPRECIATION EXPENSE		203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
11	DE								
12	DE	G404.3 AMORT OF OTHER LIMITED TERM PLANT							
13	DE	Customer Service related	CUSTSVSX	1,194,362	0	82,628	0	909,279	202,455
14	DE	AWMS	DISTPLT	0	0	0	0	0	0
15	DE	Distribution	CHOICE_04	1,127,553	0	1,127,553	0	0	0
16	DE	Metering	METERPLT	29,719	0	0	0	0	29,719
17	DE	All Other	PSTDPLT	0	0	0	0	0	0
18	DE	TOTAL AMORT OF OTHER LIMITED TERM PLT		2,351,634	0	1,210,181	0	909,279	232,173
19	DE								
20	DE	G407 AMORT OF PROPERTY LOSSES							
21	DE	Remediation Adjustment Clause	not_used	0	0	0	0	0	0
22	DE	Excess Cost of Removal	TOTPLT						
23	DE	TOTAL AMORT OF PROPERTY LOSSES		0	0	0	0	0	0
24	DE								
25	DE	TOTAL AMORTIZATION EXPENSE		2,351,634	0	1,210,181	0	909,279	232,173
26	DE								
27	DE	**TOTAL DEPRECIATION AND AMORTIZATION EXPENSES**		206,042,850	108,184,098	81,546,856	19,302	4,626,919	11,665,674

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	EO	**OTHER OPERATING EXPENSES**							
2	EO								
3	EO	**G408 TAXES OTHER THAN INCOME TAXES**							
4	EO	Payroll	LABOR	-2,034	-189	-1,115	-1	-466	-263
5	EO	TEFA	TEFA_04	0	0	0	0	0	0
6	EO	Real Estate Taxes	TOTPLT	-13,552,354	-7,219,321	-5,476,185	-1,288	-86,423	-769,137
7	EO	State Unemploy Insur (SUI) Tax	LABOR	0	0	0	0	0	0
8	EO	Fed Insur Contr & UnempTax	LABOR	-60,481	-5,619	-33,152	-29	-13,869	-7,813
9	EO	Fed Insur Contr & UnempTax - Gas Peaking Plts	BALANCE_04	0	0	0	0	0	0
10	EO	FICA	LABOR	-10,865,853	-1,009,467	-5,955,913	-5,144	-2,491,669	-1,403,661
11	EO	Miscellaneous State and Municipal Tax	TOTPLT	0	0	0	0	0	0
12	EO	Federal Environmental Tax	PSTDPLT	0.0	0.0	0.0	0.0	0.0	0.0
13	EO	**TOTAL TAXES OTHER THAN INCOME**		-24,480,722	-8,234,596	-11,466,364	-6,462	-2,592,427	-2,180,874
14	EO								
15	EO	**PROFORMA EXPENSE ADJUSTMENTS**							
16	EO	Amortization of CEF-EC Program Regulatory Assets		0	0	0	0	0	0
17	EO	Amortization of CEF-EV Program Regulatory Assets		0	0	0	0	0	0
18	EO	BGS Administrative Expense Adjustment		0	0	0	0	0	0
19	EO	CIP Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
20	EO	Deferred Compensation & Severance Expense	LABOR	-682,298	-63,387	-373,989	-323	-156,459	-88,140
21	EO	Gas Bad Debt Adjustment	not_used	0	0	0	0	0	0
22	EO	TAC Revenue Accrual Adjustment	not_used	0	0	0	0	0	0
23	EO	Tax Bad Debt Adjustment	SALESREV	4,884,054	2,407,252	1,808,424	1,403	281,559	385,417
24	EO	TSG-NF Gas Margin Reset	not_used	0	0	0	0	0	0
25	EO	Wage Increases (Rate Year)	LABOR	6,746,929	626,808	3,698,202	3,194	1,547,151	871,574
26	EO	Payroll Taxes (Rate Year)	LABOR	463,867	43,095	254,260	220	106,370	59,923
27	EO	Interest Syncronization	TOTPLTNET	-1,266,764	-699,209	-484,443	-158	-5,125	-77,829
28	EO	- add'l tax effects on rev req	TOTPLTNET	-495,322	-273,400	-189,424	-62	-2,004	-30,432
29	EO	Pension & Fringe Benefit (Rate Year)	LABOR	15,610,563	1,450,264	8,556,636	7,390	3,579,687	2,016,587
30	EO	Adj #5 - Gas COLI Interest Expense	LABOR	0	0	0	0	0	0
31	EO	- add'l tax effects on rev req	LABOR	0	0	0	0	0	0
32	EO	Postage	CUSTACCTS	0	0	0	0	0	0
33	EO	BPU / Rate Counsel Assessment	TRANSPORT_04	0	0	0	0	0	0
34	EO	Adj #6 - Weather Normalization	not_used	0	0	0	0	0	0
35	EO	Gains / Losses Normalization	TOTPLT	-207,450	-110,508	-83,826	-20	-1,323	-11,773
36	EO	- add'l tax effects on rev req	TOTPLT	-81,116	-43,210	-32,777	-8	-517	-4,604
37	EO	Test Year Corrections	TOTPLT	0	0	0	0	0	0
38	EO	Customer Information System Amort	CUSTSVSX	0	0	0	0	0	0
39	EO	Real Estate Tax Increases (Rate Year)	TOTPLT	-328,894	-175,201	-132,898	-31	-2,097	-18,666
40	EO	Capital Stimulus (Depreciation)	DISTPLT	0	0	0	0	0	0
41	EO	Insurance Premium Increases (Rate Year)	TOTPLT	262,863	140,027	106,217	25	1,676	14,918
42	EO	Adj #15 - Excess COR Refund Recovery	TOTPLT	0	0	0	0	0	0
43	EO	Test Year Amortization Adjustments	TOTPLT	-5,932,749	-3,160,368	-2,397,283	-564	-37,833	-336,702
44	EO	Adj #11 - TSGNF Margin Sharing	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	EO	Adj #12 - Depreciation Rate Change/Annualization	DEPREXP	0	0	0	0	0	0
46	EO	Capital Stimulus Revenue	DISTPLT	0	0	0	0	0	0
47	EO	ASB Margin	TOTPLT	14,761,516	7,863,441	5,964,779	1,403	94,133	837,761
48	EO	Adj #13 - Storm Cost Amortization	TOTPLTNET	0	0	0	0	0	0
49	EO	Other Regulatory Asset / Liability Amortizations	TOTPLT	0	0	0	0	0	0
50	EO	Rate Case Expenses	TOTPLT	150,424	80,131	60,783	14	959	8,537
51	EO	Tax - Repair Allowance	DISTPLT	0	0	0	0	0	0
52	EO	Tax - Flow Through Items	DISTPLT	0	0	0	0	0	0
53	EO	Adj #14 Post Rate Case Storm Cost Normalization	TOTPLT	0	0	0	0	0	0
54	EO	Recovery of Credit Card Fees	CUSTSVSX	0	0	0	0	0	0
55	EO	Adj #20 - Vacation Accrual	LABOR	0	0	0	0	0	0
56	EO	Energy Strong II / IAP Revenue Adjustment	TOTPLT						
57	EO	Depreciation Rate Change	DEPREXP	71,386,007	37,914,403	28,154,942	6,765	1,302,891	4,007,006
58	EO	TOTAL PROFORMA EXPENSE ADJUSTMENTS		105,999,447	46,067,751	45,308,541	19,592	6,875,966	7,727,598
59	EO								
60	EO	**TOTAL OTHER OPERATING EXPENSES**		81,518,725	37,833,154	33,842,178	13,131	4,283,539	5,546,724
61	EO	COLI Interest Expense Recovery	LABOR	727,815	67,616	398,938	345	166,897	94,020

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	TI	**DEVELOPMENT OF INCOME TAXES**							
2	TI								
3	TI	TOTAL OPERATING REVENUES	CALCULATED	1,452,575,331	692,340,976	567,960,291	403,179	80,960,814	110,910,071
4	TI	LESS:							
5	TI	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	281,722,708	46,315,172	122,801,736	265,586	72,527,282	39,812,932
6	TI	DEPRECIATION & AMORTIZATION EXPENSE	CALCULATED	206,042,850	108,184,098	81,546,856	19,302	4,626,919	11,665,674
7	TI	OTHER OPERATING EXPENSES	CALCULATED	81,518,725	37,833,154	33,842,178	13,131	4,283,539	5,546,724
8	TI	NET OPERATING INCOME BEFORE TAXES		883,291,047	500,008,551	329,769,521	105,160	-476,925	53,884,740
9	TI	LESS:							
10	TI	G427 - G431 INTEREST CHARGES	TOTPLTNET	100,820,068	55,649,119	38,556,163	12,592	407,888	6,194,306
11	TI	**TOTAL OPERATING INCOME BEFORE TAXES**		782,470,979	444,359,433	291,213,358	92,568	-884,814	47,690,434
12	TI								
13	TI	**TAX ADJUSTMENTS - FEDERAL**							
14	TI								
15	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	56,782	31,342	21,715	7	230	3,489
16	TI	Injuries and Damages ;		0	0	0	0	0	0
17	TI	Bankrupticies & Acc. Prov. For Rents Receivable	TOTPLTNET	52,256	28,843	19,984	7	211	3,211
18	TI	Capitalized interest-Section 263A	TOTPLT	416,892	222,078	168,456	40	2,658	23,660
19	TI	Casualty Loss Deferred O&M & Ins Proceeds	TOTPLTNET	-1,095,802	-604,844	-419,062	-137	-4,433	-67,325
20	TI	Deduction for New Network Meter Equipment		0	0	0	0	0	0
21	TI	Defer Dividend Equivalents/Restricted Stock-Temp.		0	0	0	0	0	0
22	TI	Deferred Depreciation on CIP II	TOTPLT	8,262	4,401	3,338	1	53	469
23	TI	Deferred Return on CIP II	TOTPLT	18,055	9,618	7,296	2	115	1,025
24	TI	Diesel Fuel Credit		0	0	0	0	0	0
25	TI	Environmental Accrual		0	0	0	0	0	0
26	TI	FIN48 Reg Asset Reversal		0	0	0	0	0	0
27	TI	FIN48 Services Allocation		0	0	0	0	0	0
28	TI	GainState LILOAudit Refunds not yet received		0	0	0	0	0	0
29	TI	LCAPP		0	0	0	0	0	0
30	TI	Legal Reserves (c & nc)	TOTPLTNET	-418,012	-230,728	-159,858	-52	-1,691	-25,682
31	TI	Material Supplies & Reserves	TOTPLT	78,535	41,836	31,734	7	501	4,457
32	TI	Misc Adj - Permanent		0	0	0	0	0	0
33	TI	Miscellaneous		0	0	0	0	0	0
34	TI	Partnership income/loss per K-1		0	0	0	0	0	0
35	TI	Performance Incentive Plan Adjustment	TOTPLTNET	-455,695	-251,528	-174,269	-57	-1,844	-27,998
36	TI	RAC-Environmental Cleanup Costs		0	0	0	0	0	0
37	TI	Repair Allow Deferral Carrying Charges		0	0	0	0	0	0
38	TI	SBC-Societal Benefits Clause		0	0	0	0	0	0
39	TI	Stock Based Compensation	TOTPLTNET	-325,229	-179,515	-124,376	-41	-1,316	-19,982
40	TI	TAX ADJUSTMENTS - FEDERAL CONTINUED		0	0	0	0	0	0
41	TI	Uncollectible Accounts		0	0	0	0	0	0
42	TI	Utility Commodity Costs		0	0	0	0	0	0
43	TI	Additional Expenses on Rental Property	TOTPLT	0	0	0	0	0	0
44	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
46	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
47	TI	Amortization of Limited-Term Utility Plant	TOTPLT	-14	-7	-6	0	0	-1
48	TI	Amortization of Reacquisition of Pref Stock	TOTPLT	7,787	4,148	3,146	1	50	442
49	TI	CECL Reserve	not_used	0	0	0	0	0	0
50	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
51	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
52	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0
53	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
54	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
55	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
56	TI	Company Owned Life Insurance - Book	LABOR	-352,245	-32,725	-193,077	-167	-80,774	-45,503
57	TI	Company Owned Life Insurance - Tax	LABOR	-14,570	-1,354	-7,986	-7	-3,341	-1,882
58	TI	COVID Deferrals	not_used	0	0	0	0	0	0
59	TI	Current SHARE -- FT	DEPREXP	-21,771,486	-11,563,231	-8,586,766	-2,063	-397,359	-1,222,067
60	TI	Customer Advances	TOTPLTNET	294,687	162,657	112,696	37	1,192	18,105
61	TI	Customer Connection Fees (Contributions in Aid of Constructi	TOTPLTNET	0	0	0	0	0	0
62	TI	Deduction for Retention Payments (c)	LABOR	-4,379	-407	-2,400	-2	-1,004	-566
63	TI	Deferred Employer ER FICA	LABOR	-5,798,258	-538,674	-3,178,206	-2,745	-1,329,609	-749,024
64	TI	Diesel Fuel Tax Credit	TOTPLT	928	494	375	0	6	53
65	TI	Entertainment (100%)	LABOR	36,298	3,372	19,896	17	8,324	4,689
66	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
67	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
68	TI	Injuries & Damages - FT	TOTPLT	1,044,758	556,541	422,162	99	6,662	59,293
69	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
70	TI	Plant Related	DEPREXP	-61,904,159	-32,878,422	-24,415,262	-5,866	-1,129,835	-3,474,776
71	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
72	TI	Qualified Transportation Fringe	LABOR	139,386	12,949	76,402	66	31,963	18,006
73	TI	R & D Credits CF	not_used	0	0	0	0	0	0
74	TI	R&D Credit - Fed	TOTPLT	-75,718	-40,335	-30,596	-7	-483	-4,297
75	TI	R&D Expenditure	TOTPLT	-16,866	-8,984	-6,815	-2	-108	-957
76	TI	Rabbi Trust	not_used	0	0	0	0	0	0
77	TI	RE - Lease Liability	TOTPLT	-519,350	-276,657	-209,857	-49	-3,312	-29,475
78	TI	RE - ROU Lease Asset	TOTPLT	594,984	316,947	240,419	57	3,794	33,767
79	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
80	TI	Severance Pay (nc)	LABOR	121,791	11,315	66,757	58	27,928	15,733
81	TI	State NOL CF (c)	DEPREXP	7,732,062	4,106,638	3,049,558	733	141,121	434,013
82	TI	Tax Net Bad Debt Writeoffs - FT	TOTPLT	-81,087	-43,195	-32,765	-8	-517	-4,602
83	TI	Unicap book/tax inventory FS	not_used	0	0	0	0	0	0
84	TI	Unrealized G/L on Equity Securities	TOTPLT	142,148	75,722	57,439	14	906	8,067
85	TI	Credits & Adjustments	TOTPLT	0	0	0	0	0	0
86	TI	Repair Allowance	TOTPLT	0	0	0	0	0	0
87	TI	Uncollectible Accounts - Writeoff	REVREQ	0	0	0	0	0	0
88	TI	Injuries and Damages	TOTPLT	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	TI	Meals & entertainment	LABOR	-459,207	-42,662	-251,706	-217	-105,302	-59,321
90	TI	Company owned life insurance	LABOR	0	0	0	0	0	0
91	TI	ESOP/401(k) Cash Dividends	TOTPLTNET	-844,650	-466,217	-323,016	-105	-3,417	-51,895
92	TI	Medicare Subsidy		0	0	0	0	0	0
93	TI	Allowable Depreciation	DEPREXP	0	0	0	0	0	0
94	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
95	TI	Amortization of Computer Software	INTANGPLT	0	0	0	0	0	0
96	TI	Amort Def Gain - Sale of Gen Asset	not_used	0	0	0	0	0	0
97	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
98	TI	AFUDC / IDC	TOTPLT	-345,079	-183,823	-139,438	-33	-2,201	-19,584
99	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
100	TI	*Utility Commodity Costs-Non-Taxable Income	not_used	0	0	0	0	0	0
101	TI	*RAC-Environmental Cleanup Costs - Debit	not_used	0	0	0	0	0	0
102	TI	*SBC-Societal Benefits Clause - Unallow Deductions	not_used	0	0	0	0	0	0
103	TI	Deferred Comp - officers	LABOR	-15,155	-1,408	-8,307	-7	-3,475	-1,958
104	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
105	TI	Accrued vacation pay adjustment	LABOR	-257,985	-23,968	-141,410	-122	-59,159	-33,327
106	TI	3rd Party Claims	TOTPLT	-975	-519	-394	0	-6	-55
107	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
108	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
109	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
110	TI	Pension Accrual Adjustment	LABOR	-7,780,352	-722,816	-4,264,653	-3,683	-1,784,127	-1,005,073
111	TI	Unallowable OPEB Amortization	LABOR	47,224,310	4,387,266	25,885,115	22,356	10,829,093	6,100,479
112	TI	NJ BPU assessment	TOTPLTNET	0	0	0	0	0	0
113	TI	Unicap book/tax inventory	TOTPLTNET	0	0	0	0	0	0
114	TI	W-2 Earnings Exceeding $1,000,000	LABOR	1,506,831	139,989	825,941	713	345,534	194,654
115	TI	Diesel Fuel Tax Credit	not_used	0	0	0	0	0	0
116	TI	Deferred Depreciation & Return on CIP ll	TOTPLTNET	0	0	0	0	0	0
117	TI	Capitalized Interest - Section 263A	TOTPLT	0	0	0	0	0	0
118	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
119	TI	Restricted Stock - Permanent	LABOR	-67,594	-6,280	-37,051	-32	-15,500	-8,732
120	TI	Materials & Supplies Reserve	TOTPLT	0	0	0	0	0	0
121	TI	Amortization of Reacquisition of Pref Stock	TOTPLTNET	0	0	0	0	0	0
122	TI	Lobbying Expenses	LABOR	0	0	0	0	0	0
123	TI	Penalties	not_used	0	0	0	0	0	0
124	TI	Dividends Received Deduction	TOTPLTNET	0	0	0	0	0	0
125	TI	Real Estate Taxes	TOTPLTNET	-1,021,308	-563,726	-390,574	-128	-4,132	-62,748
126	TI	Line Pack Adjustment	TOTPLTNET	0	0	0	0	0	0
127	TI	Legal Reserves	TOTPLTNET	0	0	0	0	0	0
128	TI	Casualty Insurance Proceeds	TOTPLT	0	0	0	0	0	0
129	TI	Miscellaneous (R&D Exp., Limit Term Util Plant, ARO Fin 47, F	TOTPLT	0	0	0	0	0	0
130	TI	**TOTAL TAX ADJUSTMENTS - FEDERAL**		-44,148,425	-38,545,866	-12,085,420	8,683	6,467,397	6,782
131	TI								
132	TI								

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	TI	**DEVELOPMENT OF INCOME TAXES CONTINUED**							
134	TI								
135	TI	**TAX ADJUSTMENTS - STATE**							
136	TI	Reverse TEFA	TEFA_04	0	0	0	0	0	0
137	TI	Federal Depreciation Reversal	TOTPLT	64,677,176	34,453,448	26,134,512	6,147	412,443	3,670,626
138	TI	State Tax Depreciation	DEPREXP	37,759,415	20,054,710	14,892,472	3,578	689,160	2,119,494
139	TI	Amortization of Service's Asset Sale	TOTPLTNET	0	0	0	0	0	0
140	TI	NOL Utilization	TOTPLTNET	0	0	0	0	0	0
141	TI	**TOTAL TAX ADJUSTMENTS - STATE**		102,436,591	54,508,158	41,026,985	9,725	1,101,603	5,790,120
142	TI								
143	TI	**TAXABLE NET INCOME - STATE**		840,759,145	460,321,724	320,154,922	110,976	6,684,187	53,487,336
144	TI	State Tax Liability		75,668,323	41,428,955	28,813,943	9,988	601,577	4,813,860
145	TI	Prior Year Adjustment & State Credit	TOTPLTNET	0	0	0	0	0	0
146	TI	**TOTAL STATE INCOME TAX LIABILITY**		75,668,323	41,428,955	28,813,943	9,988	601,577	4,813,860
147	TI								
148	TI	**TAXABLE NET INCOME - FEDERAL**		662,654,232	364,384,611	250,313,995	91,263	4,981,007	42,883,356
149	TI	Federal Tax Liability		139,157,389	76,520,768	52,565,939	19,165	1,046,011	9,005,505
150	TI	Prior Yr & Oth Adjustments	TOTPLTNET	0	0	0	0	0	0
151	TI	Not Used	not_used	0	0	0	0	0	0
152	TI	**TOTAL FEDERAL INCOME TAX LIABILITY**		139,157,389	76,520,768	52,565,939	19,165	1,046,011	9,005,505
153	TI								
154	TI	**TOTAL INCOME TAX EXPENSE**		214,825,712	117,949,724	81,379,882	29,153	1,647,588	13,819,365
155	TI								
156	TI	**TAX RATES**							
157	TI	FEDERAL TAX RATE - CURRENT		21.000%					
158	TI	NEW JERSEY CORP BUSINESS TAX RATE		9.000%					
159	TI	CUSTOMER ACCT UNCOLLECTIBLE RATE		0.000					
160	TI	EFFECTIVE TAX RATE		28.110%					
161	TI	COMPOSITE RATE		28.110%					
162	TI	1 - EFFECTIVE TAX RATE		71.89000%					
163	TI								
164	TI	**DEVELOPMENT OF OPERATING INCOME ADJUSTED**							
165	TI								
166	TI	**G410 + G411- PROVISION FOR DEFERRED INCOME TAX**							
167	TI	Additional Rental Income - NJ Properties	TOTPLT	0	0	0	0	0	0
168	TI	Amort of Def Gain on Sale of Services Assets	not_used	0	0	0	0	0	0
169	TI	Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
170	TI	Amortization of Limited-Term Utility Plant	TOTPLT	14	7	6	0	0	1
171	TI	Bankruptcies and Accum Provision for Rent Receivable	TOTPLT	-31,746	-16,911	-12,828	-3	-202	-1,802
172	TI	Casualty Loss Deferred O&M	TOTPLTNET	1,095,802	604,844	419,062	137	4,433	67,325
173	TI	CECL Reserve	not_used	0	0	0	0	0	0
174	TI	CEF- EC AMI	TOTPLT	0	0	0	0	0	0
175	TI	CEF- EV Deferral	TOTPLT	0	0	0	0	0	0
176	TI	Clause - Demographic Studies	not_used	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
177	TI	Clause - Navigant Studies	not_used	0	0	0	0	0	0
178	TI	Clause - RAC (Environmental Clean Up)	not_used	0	0	0	0	0	0
179	TI	Clause - Societal Benefits Clause (AAP)	not_used	0	0	0	0	0	0
180	TI	COVID Deferrals	not_used	0	0	0	0	0	0
181	TI	Current SHARE -- FT	DEPREXP	5,506,769	2,924,745	2,171,893	522	100,506	309,103
182	TI	Customer Advances	TOTPLTNET	-294,687	-162,657	-112,696	-37	-1,192	-18,105
183	TI	Deduction for Retention Payments (c)	LABOR	4,379	407	2,400	2	1,004	566
184	TI	Deferred Employer ER FICA	LABOR	5,798,258	538,674	3,178,206	2,745	1,329,609	749,024
185	TI	FAS 5 (ASC40) Reserve - Sales Tax	not_used	0	0	0	0	0	0
186	TI	Fed Amort of Deferred Gain on Sale of Generation Assets	not_used	0	0	0	0	0	0
187	TI	Injuries & Damages - FT	TOTPLT	-264,256	-140,769	-106,780	-25	-1,685	-14,997
188	TI	Line Pack Adjustment	not_used	0	0	0	0	0	0
189	TI	Medicare Subsidy	not_used	0	0	0	0	0	0
190	TI	Partnership Income/Loss (nc)	TOTPLT	0	0	0	0	0	0
191	TI	Plant Related	DEPREXP	62,706,788	33,304,712	24,731,822	5,942	1,144,484	3,519,828
192	TI	Previously Deducted Amort - Reacquired Bonds	not_used	0	0	0	0	0	0
193	TI	R & D Credits CF	TOTPLT	-67,859	-36,148	-27,420	-6	-433	-3,851
194	TI	RE - Lease Liability	TOTPLT	519,350	276,657	209,857	49	3,312	29,475
195	TI	RE - ROU Lease Asset	TOTPLT	-594,984	-316,947	-240,419	-57	-3,794	-33,767
196	TI	Real Estate Taxes (nc)	TOTPLT	1,021,308	544,049	412,686	97	6,513	57,962
197	TI	Reversal of Book Income from Partnerships	TOTPLT	0	0	0	0	0	0
198	TI	Severance Pay (nc)	LABOR	-121,791	-11,315	-66,757	-58	-27,928	-15,733
199	TI	State NOL CF (c)	DEPREXP	-7,732,062	-4,106,638	-3,049,558	-733	-141,121	-434,013
200	TI	Unrealized G/L on Equity Securities	TOTPLT	-142,148	-75,722	-57,439	-14	-906	-8,067
201	TI	Previously Ded Amort-Reacq Bonds	not_used	0	0	0	0	0	0
202	TI	Clause - Deferred Fuel	not_used	0	0	0	0	0	0
203	TI	Gain on Sale of Services Corp Asset	not_used	0	0	0	0	0	0
204	TI	AFUDC / IDC	TOTPLT	345,079	183,823	139,438	33	2,201	19,584
205	TI	Capitalized interest-Section 263A	TOTPLT	-416,892	-222,078	-168,456	-40	-2,658	-23,660
206	TI	Cost of removal	TOTPLT	0	0	0	0	0	0
207	TI	Deferred Comp - officers	LABOR	15,155	1,408	8,307	7	3,475	1,958
208	TI	Deduction of Securitizartion	not_used	0	0	0	0	0	0
209	TI	Accrued vacation pay adjustment	LABOR	257,985	23,968	141,410	122	59,159	33,327
210	TI	Gain/loss bond reacq	not_used	0	0	0	0	0	0
211	TI	Amortization of Call Option Sale	LABOR	0	0	0	0	0	0
212	TI	Defer Dividend Equivalents/Restricted Stock-Temp.	LABOR	0	0	0	0	0	0
213	TI	Contribution in Aid of Construct	TOTPLTNET	0	0	0	0	0	0
214	TI	Pension Accrual Adjustment	LABOR	7,780,352	722,816	4,264,653	3,683	1,784,127	1,005,073
215	TI	Unallowable OPEB Amortization	LABOR	-47,224,310	-4,387,266	-25,885,115	-22,356	-10,829,093	-6,100,479
216	TI	Fin Def-Energy Competition Act Ct	TOTPLT	0	0	0	0	0	0
217	TI	Rabbi Trust Unrealized Losses		0	0	0	0	0	0
218	TI	Additional Real Estate Taxes	TOTPLT	0	0	0	0	0	0
219	TI	PIP Adjustment	LABOR	455,695	42,335	249,781	216	104,496	58,867
220	TI	Deferred NJ Corp Bus Tax(Net of FIT)	TOTPLTNET	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
221	TI	Misc	TOTPLT	0	0	0	0	0	0
222	TI	Construction Period Interest	TOTPLTNET	0	0	0	0	0	0
223	TI	Deferred Return on CIP II	TOTPLT	-18,055	-9,618	-7,296	-2	-115	-1,025
224	TI	Deferred Depreciation on CIP II	TOTPLT	-8,262	-4,401	-3,338	-1	-53	-469
225	TI	Investment Tax Credit	TOTPLT	-493,265	-262,762	-199,317	-47	-3,146	-27,994
226	TI	Assessment by Board of Public Utilities of the State of NJ	TOTPLTNET	-56,782	-31,342	-21,715	-7	-230	-3,489
227	TI	3rd Party Claims	TOTPLT	975	519	394	0	6	55
228	TI	Customer Connections Fees		0	0	0	0	0	0
229	TI	Legal Reserves (nc)	TOTPLTNET	418,012	230,728	159,858	52	1,691	25,682
230	TI	Material Supplies & Reserves	TOTPLTNET	-78,535	-43,349	-30,034	-10	-318	-4,825
231	TI	Stock Based Compensation	TOTPLTNET	325,229	179,515	124,376	41	1,316	19,982
232	TI	**TOTAL DEFERRED INCOME TAX**		28,705,516	29,751,285	6,224,982	-9,746	-6,466,542	-794,464
233	TI								
234	TI	**This Section is not used at this time**							
235	TI	**PROFORMA OPERATING INCOME ADJUSTMENTS**							
236	TI	Not Used	not_used	0	0	0	0	0	0
237	TI	Not Used	not_used	0	0	0	0	0	0
238	TI	Not Used	not_used	0	0	0	0	0	0
239	TI	**OPERATING INCOME ADJUSTED**		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	LR	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**							
2	LR	Labor portion included in O&M Expense							
3	LR								
4	LR	**G700-G742 MANUFACTURED GAS LABOR EXP**	MFGO_M	778,312	0	778,312	0	0	0
5	LR	**G813 GAS SUPPLY LABOR EXPENSE**	EXP_813	0	0	0	0	0	0
6	LR	**G840-G843 STORAGE PLANT LABOR EXP**	STOREXP	407,976	0	407,976	0	0	0
7	LR	**G850-G867 TRANSMISSION LABOR EXP**	TRANEXP	483,267	0	483,267	0	0	0
8	LR								
9	LR	**DISTRIBUTION LABOR EXPENSE**							
10	LR	Operation							
11	LR	G870 Operation Supervision & Engineering	TLABDO	0	0	0	0	0	0
12	LR	G871 Load Dispatching	EXP_871	4,522,112	0	4,522,112	0	0	0
13	LR	G872 Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
14	LR	G874 Mains & Services	EXP_874	14,351,672	8,477,124	5,874,548	0	0	0
15	LR	G875-877 Meas & Reg Station	EXP_8757	1,368,583	0	1,368,583	0	0	0
16	LR	G878 Meter & House Reg	EXP_878	8,562,092	1,901,176	0	0	0	6,660,916
17	LR	G879 Customer Installations - Total	EXP_879	63,057,319	0	63,057,319	0	0	0
18	LR	G880.1 Miscellaneous Dist Exp	EXP_8801	5,219,383	1,346,785	3,058,957	0	0	813,641
19	LR	G880.3 Operation of Street Lighting	EXP_8803	0	0	0	0	0	0
20	LR	G881 Rents	EXP_881	-60	0	-60	0	0	0
21	LR	Total Operation		97,081,101	11,725,086	77,881,458	0	0	7,474,557
22	LR								
23	LR	Maintenance							
24	LR	G885 Maint. Supervision & Engineering	TLABDM	0	0	0	0	0	0
25	LR	G886 Structures & Improvements	EXP_886	1,015,469	553,706	402,845	99	0	58,819
26	LR	G887 Mains	EXP_887	4,445,965	0	4,445,965	0	0	0
27	LR	G888 Compressor Station Equip	EXP_888	0	0	0	0	0	0
28	LR	G889-891 Meas & Reg Station	EXP_8891	2,185,363	0	2,185,363	0	0	0
29	LR	G892 Services	EXP_892	2,126,460	2,126,460	0	0	0	0
30	LR	G893 Meters & House Reg	EXP_893	5,044,535	0	0	0	0	5,044,535
31	LR	G894 Maint of Other Equipment - Total	EXP_894	71,094	825	1,659	67,862	0	748
32	LR	Not Used	not_used	0	0	0	0	0	0
33	LR	Total Maintenance		14,888,885	2,680,991	7,035,832	67,960		5,104,101
34	LR	TOTAL DISTRIBUTION LABOR EXPENSE		111,969,986	14,406,077	84,917,290	67,960	0	12,578,658
35	LR								
36	LR	**G901-G903,G905 CUST ACCOUNTS EXPENSE**	CUSTACCTS	45,109,566	0	1,682,855	0	35,356,012	8,070,699
37	LR	**G907-G910, xDSM CUST SERV & INFO EXP**	CUSTS_I	3,007,750	0	1,936,120	0	1,071,630	0
38	LR	**G911-G916 SALES EXPENSE**	SALESEXP	3,526	0	3,526	0	0	0
39	LR	**ADMIN & GENERAL EXP ACCOUNTS xG926**	AGEXP	6,954,680	1,268,009	2,268,636	11,910	2,260,717	1,145,408
40	LR	**Employee Pension/Benefits Acct G926**	LABOR	0	0	0	0	0	0
41	LR								
42	LR	**TOTAL OPERATION & MAINT LABOR EXPENSE**		168,715,063	15,674,086	92,477,982	79,870	38,688,359	21,794,766

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	CA	**DEVELOPMENT OF CAPITAL ADDITIONS ALLOCATION F**							
2	CA								
3	CA	**INTANGIBLE PLANT - G301-G303**	INTANGPLT	0	0	0	0	0	0
4	CA	**PRODUCTION PLANT - G304-G347**	PRODPLT	-2,267,387	0	-2,267,387	0	0	0
5	CA	**STORAGE PLANT - G360-G363**	STORPLT	8,371,561	0	8,371,561	0	0	0
6	CA	TRANSMISSION PLANT - G365-G371	TRANPLT	11	0	11	0	0	0
7	CA								
8	CA	**DISTRIBUTION PLANT**							
9	CA	G374 Land and Land Rights & G375 Structure & Improveme	PLT_3745	2,620,552	1,428,913	1,039,595	255	0	151,789
10	CA	G376 Mains	PLT_376	226,633,216	0	226,633,216	0	0	0
11	CA	G377 Compressor Station Equipment	PLT_377	0	0	0	0	0	0
12	CA	G378-G379 Meas & Regul Eqmt	PLT_3789	57,069,064	0	57,069,064	0	0	0
13	CA	G380 Services	SERVICES	505,466,924	505,466,924	0	0	0	0
14	CA	G381 Meters	PLT_381	58,899,779	0	0	0	0	58,899,779
15	CA	G382 Meter Installations	PLT_382	-1,810,761	0	0	0	0	-1,810,761
16	CA	G383-384 House Regulators & Install	PLT_3834	2,268,333	2,268,333	0	0	0	0
17	CA	G385 Ind Reg & Meas Eqmt	PLT_385	12,739,212	6,369,606				6,369,606
18	CA	TOTAL DISTRIBUTION PLANT		863,886,319	515,533,776	284,741,875	255	0	63,610,413
19	CA								
20	CA	**COMMON PLANT**	COMPLT	0	0	0	0	0	0
21	CA	**GENERAL PLANT EXCL INTANGIBLE PLT**	GENPLT	26,119,255	15,109,213	10,992,591	2,696	0	14,755
22									
23	CA	**TOTAL CAPITAL ADDITIONS**		896,109,759	530,642,989	301,838,650	2,951	0	63,625,169

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AF	**ALLOCATION FACTOR TABLE**							
2	AF	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AF								
4	AF	**CAPACITY RELATED**							
5	AF	Peak-Hour Sendout - delivery	PEAKHOUR_04	124,747	0	124,747	0	0	0
6	AF								
7	AF	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1	0	1	0	0	0
8	AF	**COMMODITY RELATED**							
9	AF	Annual transported gas @mtr - delivery	TRANSPORT_04	2,598,285,838	0	2,598,285,838	0	0	0
10	AF	Balancing therms - delivery	BALANCE_04	1,793,060	0	1,793,060	0	0	0
11	AF	Annual transported gas @mtr - access	TRANSPORT_03	2,598,285,838	2,598,285,838	0	0	0	0
12	AF	Annual transported gas @mtr - meters	TRANSPORT_07	2,598,285,838	0	0	0	0	2,598,285,838
13	AF	TEFA $ responsibility W/N - delivery	TEFA_04						
14	AF								
15	AF	**BILLING DETERMINANTS**							
16	AF	Number of Customers		1,894,095	1,894,095	1,894,095	1,894,095	1,894,095	1,894,095
17	AF	Transported Gas at Meter (calendar)		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
18	AF								
19	AF								
20	AF	**CUSTOMER RELATED**							
21	AF	G380 services - access	SERVICES_03	1,215,746,207	1,215,746,207	0	0	0	0
22	AF	Cust Installns LDC G879 - delivery	CINST_04	100	0	100	0	0	0
23	AF	Avg Customer Bills - delivery	CUSTAVG_04	661,048	0	661,048	0	0	0
24	AF	Avg Customer Bills - cust svs	CUSTAVG_06	661,048	0	0	0	661,048	0
25	AF	G381 meters - measurement	SMMETERS_07	95,373,410	0	0	0	0	95,373,410
26	AF								
27	AF	Billing Function costs - cust svs	BILLING_06	20,835,825	0	0	0	20,835,825	0
28	AF	Competitive Service work - delivery	COMPSVSWK_04	100	0	100	0	0	0
29	AF								
30	AF	Account Maint - cust svs	ACCTMAINT_06	67,192,728	0	0	0	67,192,728	0
31	AF	G382 meter install - measurement	MTRINSTAL_07	149,490,257	0	0	0	0	149,490,257
32	AF	G383 house regulators - access	HOUSEREG_03	27,726,351	27,726,351	0	0	0	0
33	AF	G384 house reg install - access	HSEREGINST_03	49,550,462	49,550,462	0	0	0	0
34	AF	G385 lrg regulators - access	LRGREG_03	42,370,365	42,370,365	0	0	0	0
35	AF	G385 lrg mtrs - measurement	LRGMTR_07	6,790,868	0	0	0	0	6,790,868
36	AF	G380 services - reserve - access	SERVICESR_03	302,262,539	302,262,539	0	0	0	0
37	AF	G381 meters - reserve - measurement	SMMETERSR_07	39,637,552	0	0	0	0	39,637,552
38	AF	G382 meter install - reserve -measurement	MTRINSTALR_07	70,947,597	0	0	0	0	70,947,597
39	AF	G383 house regulators - reserve - access	HOUSEREGR_03	4,745,170	4,745,170	0	0	0	0
40	AF	G384 house reg install - reserve - access	HSEREGINSTR_03	9,880,504	9,880,504	0	0	0	0
41	AF	G385 lrg regulators - reserve - access	LRGREGR_03	6,940,251	6,940,251	0	0	0	0
42	AF	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1,112,795	0	0	0	0	1,112,795
43	AF	Direct LVG - delivery	DIRLVG_04	0	0	0	0	0	0
44	AF	Direct LVG - cust svs	DIRLVG_06	0	0	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	AF	ALLOCATION FACTOR TABLE							
46	**AF**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AF								
48	AF	Direct SLG - streetlights	DIRSLG_05	1	0	0	1	0	0
49	AF	Meter Reading Costs - measurement	MRCOST_07	16,284,753	0	0	0	0	16,284,753
50	AF	Other Utility work by Cust Ops - delivery	UTILWORK_04	6,776,917	0	6,776,917	0	0	0
51	AF	Direct SLG - access	DIRSLG_03	1	1	0	0	0	0
52	AF	Direct Competitive Services - delivery	DIRCOMPSVS_04	0	0	0	0	0	0
53	AF	Direct TSG-F - access	DIRTSGF_03	0	0	0	0	0	0
54	AF	Direct TSG-F - delivery	DIRTSGF_04	0	0	0	0	0	0
55	AF	Direct TSG-F - measurement	DIRTSGF_07	0	0	0	0	0	0
56	AF	Direct - RSG - delivery	DIRRSG_04	0	0	0	0	0	0
57	AF	Choice - delivery	CHOICE_04	1,894,095	0	1,894,095	0	0	0
58	AF								
59	AF								
60	AF	Dummy allocator for unused lines	not_used	0	0	0	0	0	0
61	AF								
62	AF								
63	AF	**Plant Related**							
64	AF	Acct G301-G303 Intangible Plt	INTANGPLT	0	0	0	0	0	0
65	AF	Acct G399.10-23 Oth Tangible Plt	TANGPLT	16,791,854	283,770	1,334,206	51	12,410,339	2,763,489
66	AF	Production Plant Total	PRODPLT	52,043,670	0	52,043,670	0	0	0
67	AF	Storage Plant Total	STORPLT	19,575,233	0	19,575,233	0	0	0
68	AF	Transmission Plant Total	TRANPLT	103,544,395	0	103,544,395	0	0	0
69	AF	Distribution Plant Total	DISTPLT	10,498,076,770	5,724,304,805	4,164,673,568	1,021,319	0	608,077,078
70	AF	G391-G398 General Plant	GENPLT	200,812,197	116,163,890	84,514,137	20,726	0	113,444
71	AF	Common Plant	COMPLT	102,234,955	15,246,506	16,357,253	2,720	57,691,885	12,936,591
72	AF	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	303,047,153	131,410,396	100,871,390	23,446	57,691,885	13,050,035
73	AF	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	10,673,240,067	5,724,304,805	4,339,836,866	1,021,319	0	608,077,078
74	AF	Total Plant	TOTPLT	10,993,079,074	5,855,998,970	4,442,042,462	1,044,816	70,102,224	623,890,602
75	AF								
76	AF	Distribution Plant x Meters & Installs	DISTPLTXMTR	9,895,589,959	5,724,304,805	4,164,673,568	1,021,319	0	5,590,267
77	AF	Acct G374-375 - Land & Structures	PLT_3745	96,512,525	52,625,554	38,287,314	9,389	0	5,590,267
78	AF	Acct G376 - Mains	PLT_376	3,775,184,891	0	3,775,184,891	0	0	0
79	AF	Acct G377 - Compressor Station Equip	PLT_377	0	0	0	0	0	0
80	AF	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	285,986,290	0	285,986,290	0	0	0
81	AF	Acct G380 & 387.2 - Services	SERVICES	5,447,689,486	5,447,689,486	0	0	0	0
82	AF	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	9,222,874,377	5,447,689,486	3,775,184,891	0	0	0
83	AF	Acct G381 - House Meters	PLT_381	477,048,047	0	0	0	0	477,048,047
84	AF	Acct G382 - Meter Installations	PLT_382	52,631,537	0	0	0	0	52,631,537
85	AF	Acct G381,382, & 385 - Meters	METERPLT	602,486,811	0	0	0	0	602,486,811
86	AF	Acct G381-384 - Meters & House Regulators	PLT_3814	680,862,120	151,182,537	0	0	0	529,679,583
87	AF	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	203,814,074	151,182,537	0	0	0	52,631,537
88	AF	Acct G383-384 - House Reg & Installation	PLT_3834	151,182,537	151,182,537	0	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	**AF**	**ALLOCATION FACTOR TABLE CONTINUED**							
90	**AF**	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AF								
92	AF	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	145,614,455	72,807,227	0	0	0	72,807,227
93	AF	Acct G386 - Other Property on Cust Premises	PLT_386	0	0	0	0	0	0
94	AF	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1,011,930	0	0	1,011,930	0	0
95	AF								
96	AF	Total Distribution Plant Reserve	TOTDRESERVE	2,718,471,978	1,288,707,941	1,277,621,837	11,318	36,625,623	115,505,260
97	AF	Total Net Plant	TOTPLTNET	8,274,607,096	4,567,291,030	3,164,420,625	1,033,497	33,476,602	508,385,342
98	AF								
99	AF								
100	AF	**Revenue Related**							
101	AF	Total Operating Revenue	TOTREV	1,452,575,331	692,340,976	567,960,291	403,179	80,960,814	110,910,071
102	AF	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	208,088,289	49,372,372	144,097,748	0	4,066,764	10,551,405
103	AF								
104	AF								
105	AF	**Expense Related**							
106	AF	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	2,114,238	0	2,114,238	0	0	0
107	AF	Other Storage Plant O&M Expense	STOREXP	2,714,605	0	2,714,605	0	0	0
108	AF	Transmission Plant O&M Expense	TRANEXP	2,593,507	0	2,593,507	0	0	0
109	AF	Acct 813-Other Gas Supply Expense	EXP_813	72	0	72	0	0	0
110	AF	Acct 871 - Distribution Load Dispatching	EXP_871	5,839,316	0	5,839,316	0	0	0
111	AF	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0	0	0	0	0	0
112	AF	Acct 874-Mains & Services Expenses	EXP_874	20,733,577	12,246,734	8,486,843	0	0	0
113	AF	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	3,019,152	0	3,019,152	0	0	0
114	AF	Acct 878 - Meter & House Regulator Expenses	EXP_878	11,492,061	2,551,763	0	0	0	8,940,298
115	AF	Acct 879 - Customer Installation Expenses	EXP_879	17,355,157	0	17,355,157	0	0	0
116	AF	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	14,050,188	3,625,445	8,234,483	0	0	2,190,260
117	AF	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0	0	0	0	0	0
118	AF	Acct 881 - Rents	EXP_881	-1,088,602	0	-1,088,602	0	0	0
119	AF	Acct 886-Maint of Structures & Improvements Exp	EXP_886	8,016,449	4,371,143	3,180,191	780	0	464,334
120	AF	Acct 887-Maint of Mains Exp	EXP_887	8,706,285	0	8,706,285	0	0	0
121	AF	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0	0	0	0	0	0
122	AF	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	4,163,462	0	4,163,462	0	0	0
123	AF	Acct 892-Main of Services Exp	EXP_892	3,610,466	3,610,466	0	0	0	0
124	AF	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	6,767,990	0	0	0	0	6,767,990
125	AF	Acct 894-Maint of Other Equipment	EXP_894	207,897	2,413	4,853	198,445	0	2,187
126	AF								
127	AF	Distr Oper Exp	DISTEXPO	71,400,849	18,423,942	41,846,349	0	0	11,130,558
128	AF	Distr Maint Exp	DISTEXPM	31,472,549	7,984,022	16,054,791	199,225	0	7,234,511
129	AF	Cust Serv & Info Expense	CUSTS_I	4,034,218	0	2,596,868	0	1,437,350	0
130	AF	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	72,712,827	0	2,712,621	0	56,990,917	13,009,288
131	AF	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	76,747,044	0	5,309,489	0	58,428,267	13,009,288
132	AF	Sales Expense	SALESEXP	88,423	0	88,423	0	0	0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AF	**ALLOCATION FACTOR TABLE CONTINUED**							
134	AF	**INTERNALLY DEVELOPED ALLOCATION FACTORS**							
135	AF								
136	AF	Total O&M Expense Excl A&G Expense	TOTOMXAG	242,970,637	39,249,718	110,160,702	199,225	59,930,374	33,430,619
137	AF	Total O&M Expense Excl 904 Expense	TOTOMX904	255,675,994	33,473,420	113,155,143	265,586	71,025,175	37,756,671
138	AF	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	223,769,120	33,473,420	81,248,270	265,586	71,025,175	37,756,671
139	AF	Tot Admin & Genl Exp xPension/Ben	AGEXP	38,752,071	7,065,455	12,641,034	66,361	12,596,907	6,382,313
140	AF	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	72,712,827	0	2,712,621	0	56,990,917	13,009,288
141	AF	O&M + Capital Additions	EXPENDITURES	1,177,832,467	576,958,162	424,640,387	268,536	72,527,282	103,438,101
142	AF								
143	AF	Depreciation Expense (total)	DEPREXP	203,691,216	108,184,098	80,336,675	19,302	3,717,640	11,433,501
144	AF								
145	AF	NJ State Income Tax (CBT)	STATEINCTAX	75,668,323	41,428,955	28,813,943	9,988	601,577	4,813,860
146	AF	NJ State Deferred Income Tax	DFSTATEINCTAX	-39,443,958	-3,664,450	-21,620,462	-18,673	-9,044,966	-5,095,407
147	AF								
148	AF	**Labor Expense Related**							
149	AF	Total Distribution Exp (Oper) Labor	TLABDO	97,081,101	11,725,086	77,881,458	0	0	7,474,557
150	AF	Total Distribution Exp (Maint) Labor	TLABDM	14,888,885	2,680,991	7,035,832	67,960	0	5,104,101
151	AF	Total Labor	LABOR	168,715,063	15,674,086	92,477,982	79,870	38,688,359	21,794,766
152	AF								
153	AF	**REVENUES AND BILLING DETERMINANTS**							
154	AF								
155	AF	Base Rate Sales Revenue	SALESREV	1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
156	AF								
157	AF	Residential Service Gas	REVRSG	991,282,164	555,333,136	295,593,534	0	67,789,982	72,565,512
158	AF	General Service Gas	REVGSG	175,543,177	79,151,593	63,136,630	0	6,293,710	26,961,245
159	AF	Large Volume Service Gas	REVLVG	210,026,237	47,599,123	148,918,700	0	3,934,158	9,574,256
160	AF	Street Light Gas	REVSLG	559,485	70,977	87,554	397,774	3,157	24
161	AF	Firm Transportation Gas Service	REVTSGF	7,477,232	428,644	5,047,555	0	1,816,030	185,003
162	AF								
163	AF								
164	AF	Total Rev Req @ desired ROR	REVREQ	1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
165	AF								
166	AF								
167	AF	**PRESENT REVENUES FROM SALES INPUT**							
168	AF								
169	AF	Total Sales of Gas Revenue Requirement		0	0	0	0	0	0
170	AF	Sales of Gas Revenues - Rates		1,101,761	1,101,761	1,101,761	1,101,761	1,101,761	1,101,761
171	AF	Sales of Gas Revenues - Other		0	0	0	0	0	0
172	AF								
173	AF	**RATE OF RETURN**							
174	AF	Rate of Return (Equalized)	CALCULATED	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	AP	**ALLOCATION PROPORTIONS TABLE**							
2	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
3	AP								
4	AP	**CAPACITY RELATED**							
5	AP	Peak-Hour Sendout - delivery	PEAKHOUR_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
6	AP								
7	AP	Staff Average and Peak Allocator - delivery	AVGPEAK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
8	AP	**COMMODITY RELATED**							
9	AP	Annual transported gas @mtr - delivery	TRANSPORT_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
10	AP	Balancing therms - delivery	BALANCE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
11	AP	Annual transported gas @mtr - access	TRANSPORT_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
12	AP	Annual transported gas @mtr - meters	TRANSPORT_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
13	AP	TEFA $ responsibility W/N - delivery	TEFA_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	AF								
15	AP	**BILLING DETERMINANTS**							
16	AP	Number of Customers		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
17	AP	Transported Gas at Meter (calendar)		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
18	AP								
19	AP								
20	AP	**CUSTOMER RELATED**							
21	AP	G380 services - access	SERVICES_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
22	AP	Cust Installns LDC G879 - delivery	CINST_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
23	AP	Avg Customer Bills - delivery	CUSTAVG_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
24	AP	Avg Customer Bills - cust svs	CUSTAVG_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
25	AP	G381 meters - measurement	SMMETERS_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
26	AP								
27	AP	Billing Function costs - cust svs	BILLING_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
28	AP	Competitive Service work - delivery	COMPSVSWK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
29	AF								
30	AP	Account Maint - cust svs	ACCTMAINT_06	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
31	AP	G382 meter install - measurement	MTRINSTAL_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
32	AP	G383 house regulators - access	HOUSEREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
33	AP	G384 house reg install - access	HSEREGINST_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
34	AP	G385 lrg regulators - access	LRGREG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
35	AP	G385 lrg mtrs - measurement	LRGMTR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
36	AP	G380 services - reserve - access	SERVICESR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
37	AP	G381 meters - reserve - measurement	SMMETERSR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
38	AP	G382 meter install - reserve -measurement	MTRINSTALR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
39	AP	G383 house regulators - reserve - access	HOUSEREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
40	AP	G384 house reg install - reserve - access	HSEREGINSTR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
41	AP	G385 lrg regulators - reserve - access	LRGREGR_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
42	AP	G385 lrg mtrs - reserve - measurement	LRGMTRR_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
43	AP	Direct LVG - delivery	DIRLVG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
44	AP	Direct LVG - cust svs	DIRLVG_06	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
45	**AP**	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
46	**AP**	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
47	AP								
48	AP	Direct SLG - streetlights	DIRSLG_05	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
49	AP	Meter Reading Costs - measurement	MRCOST_07	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
50	AP	Other Utility work by Cust Ops - delivery	UTILWORK_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
51	AP	Direct SLG - access	DIRSLG_03	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
52	AP	Direct Competitive Services - delivery	DIRCOMPSVS_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
53	AP	Direct TSG-F - access	DIRTSGF_03	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
54	AP	Direct TSG-F - delivery	DIRTSGF_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
55	AP	Direct TSG-F - measurement	DIRTSGF_07	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
56	AP	Direct - RSG - delivery	DIRRSG_04	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
57	AP	Choice - delivery	CHOICE_04	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
58	AP								
59	AP								
60	AP	Dummy allocator for unused lines	not_used	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
61	AP								
62	AP								
63	AP	**Plant Related**							
64	AP	Acct G301-G303 Intangible Plt	INTANGPLT	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
65	AP	Acct G399.10-23 Oth Tangible Plt	TANGPLT	1.000000	0.016899	0.079456	0.000003	0.739069	0.164573
66	AP	Production Plant Total	PRODPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
67	AP	Storage Plant Total	STORPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
68	AP	Transmission Plant Total	TRANPLT	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
69	AP	Distribution Plant Total	DISTPLT	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
70	AP	G391-G398 General Plant	GENPLT	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
71	AP	Common Plant	COMPLT	1.000000	0.149132	0.159997	0.000027	0.564307	0.126538
72	AP	Accts C389-C399, G391-E398 Com & Gen Plt	COMGENPLT	1.000000	0.433630	0.332857	0.000077	0.190373	0.043063
73	AP	Total Prod, Storage, Transmission, & Dist Plant	PSTDPLT	1.000000	0.536323	0.406609	0.000096	0.000000	0.056972
74	AP	Total Plant	TOTPLT	1.000000	0.532699	0.404076	0.000095	0.006377	0.056753
75	AP								
76	AP	Distribution Plant x Meters & Installs	DISTPLTXMTR	1.000000	0.578470	0.420862	0.000103	0.000000	0.000565
77	AP	Acct G374-375 - Land & Structures	PLT_3745	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
78	AP	Acct G376 - Mains	PLT_376	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
79	AP	Acct G377 - Compressor Station Equip	PLT_377	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
80	AP	Acct G378-379 - Meas & Regul Station Equip	PLT_3789	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
81	AP	Acct G380 & 387.2 - Services	SERVICES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
82	AP	Acct G376, G380 & 387.2 - Mains & Services	MAIN_SERV	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
83	AP	Acct G381 - House Meters	PLT_381	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
84	AP	Acct G382 - Meter Installations	PLT_382	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
85	AP	Acct G381,382, & 385 - Meters	METERPLT	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
86	AP	Acct G381-384 - Meters & House Regulators	PLT_3814	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
87	AP	Acct G382-384 - House Reg & Install & Meter Install	PLT_3824	1.000000	0.741767	0.000000	0.000000	0.000000	0.258233
88	AP	Acct G383-384 - House Reg & Installation	PLT_3834	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
89	AP	**ALLOCATION PROPORTIONS TABLE CONTINUED**							
90	AP	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**							
91	AP								
92	AP	Acct G385 - Ind & Com Meas & Regul Station Equip	PLT_385	1.000000	0.500000	0.000000	0.000000	0.000000	0.500000
93	AP	Acct G386 - Other Property on Cust Premises	PLT_386	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
94	AP	Acct G387.1 - Other Equipment (St Ltg Posts)	PLT_387_1	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
95	AP								
96	AP	Total Distribution Plant Reserve	TOTDRESERVE	1.000000	0.474056	0.469978	0.000004	0.013473	0.042489
97	AP	Total Net Plant	TOTPLTNET	1.000000	0.551965	0.382425	0.000125	0.004046	0.061439
98	AP								
99	AP								
100	AP	**Revenue Related**							
101	AP	Total Operating Revenue	TOTREV	1.000000	0.476630	0.391002	0.000278	0.055736	0.076354
102	AP	Intra Dept Rev Req - 5.62% GS / 94.38% LV	INTRAREV	1.000000	0.237266	0.692484	0.000000	0.019543	0.050706
103	AP								
104	AP								
105	AP	**Expense Related**							
106	AP	Manufactured Gas O&M Excl Fuel Expense	MFGO_M	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
107	AP	Other Storage Plant O&M Expense	STOREXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
108	AP	Transmission Plant O&M Expense	TRANEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
109	AP	Acct 813-Other Gas Supply Expense	EXP_813	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
110	AP	Acct 871 - Distribution Load Dispatching	EXP_871	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
111	AP	Acct 872 - Compressor Station Labor & Expenses	EXP_872	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
112	AP	Acct 874-Mains & Services Expenses	EXP_874	1.000000	0.590672	0.409328	0.000000	0.000000	0.000000
113	AP	Acct 875-877 - Meas & Regulating Station Exp	EXP_8757	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
114	AP	Acct 878 - Meter & House Regulator Expenses	EXP_878	1.000000	0.222046	0.000000	0.000000	0.000000	0.777954
115	AP	Acct 879 - Customer Installation Expenses	EXP_879	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
116	AP	Acct 880.0,.1,.2 - Other Expenses	EXP_8801	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
117	AP	Acct 880.3 - Operation of Street Lighting Exp	EXP_8803	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
118	AP	Acct 881 - Rents	EXP_881	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
119	AP	Acct 886-Maint of Structures & Improvements Exp	EXP_886	1.000000	0.545272	0.396708	0.000097	0.000000	0.057923
120	AP	Acct 887-Maint of Mains Exp	EXP_887	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
121	AP	Acct 888-Maint of Compressor Station Equip Exp	EXP_888	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
122	AP	Acct 889-891 - Main of Meas & Reg Station Equip	EXP_8891	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
123	AP	Acct 892-Main of Services Exp	EXP_892	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
124	AP	Acct 893-Maint of Meters & House Regulators Exp	EXP_893	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
125	AP	Acct 894-Maint of Other Equipment	EXP_894	1.000000	0.011608	0.023342	0.954532	0.000000	0.010518
126	AP								
127	AP	Distr Oper Exp	DISTEXPO	1.000000	0.258035	0.586076	0.000000	0.000000	0.155888
128	AP	Distr Maint Exp	DISTEXPM	1.000000	0.253682	0.510120	0.006330	0.000000	0.229867
129	AP	Cust Serv & Info Expense	CUSTS_I	1.000000	0.000000	0.643710	0.000000	0.356290	0.000000
130	AP	Acct 901-903,905 Cust Acct Exp Excl 904	CACCTEXP	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
131	AP	Accts 901-910 Excl 904 - Cust Accts,Serv & Info	CUSTSVSX	1.000000	0.000000	0.069182	0.000000	0.761310	0.169509
132	AP	Sales Expense	SALESEXP	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
133	AP	Total O&M Expense Excl A&G Expense	TOTOMXAG	1.000000	0.161541	0.453391	0.000820	0.246657	0.137591
134	AP	Total O&M Expense Excl 904 Expense	TOTOMX904	1.000000	0.130921	0.442572	0.001039	0.277794	0.147674
135	AP	Total O&M Expense Excl Fuel & 904 Expense	TOMXFUEL904	1.000000	0.149589	0.363090	0.001187	0.317404	0.168730
136	AP	Tot Admin & Genl Exp xPension/Ben	AGEXP	1.000000	0.182325	0.326203	0.001712	0.325064	0.164696
137	AP	Accts 901-905 Cust Accts Exp Excl 904-Uncol	CUSTACCTS	1.000000	0.000000	0.037306	0.000000	0.783781	0.178913
138	AP	O&M + Capital Additions	EXPENDITURES	1.000000	0.489847	0.360527	0.000228	0.061577	0.087821
139	AP								
140	AP	Depreciation Expense (total)	DEPREXP	1.000000	0.531118	0.394404	0.000095	0.018251	0.056132
141	AP								
142	AP	NJ State Income Tax (CBT)	STATEINCTAX	1.000000	0.547507	0.380793	0.000132	0.007950	0.063618
143	AP	NJ State Deferred Income Tax	DFSTATEINCTAX	1.000000	0.092903	0.548131	0.000473	0.229312	0.129181
144	AP								
145	AP	**Labor Expense Related**							
146	AP	Total Distribution Exp (Oper) Labor	TLABDO	1.000000	0.120776	0.802231	0.000000	0.000000	0.076993
147	AP	Total Distribution Exp (Maint) Labor	TLABDM	1.000000	0.180067	0.472556	0.004565	0.000000	0.342813
148	AP	Total Labor	LABOR	1.000000	0.092903	0.548131	0.000473	0.229312	0.129181
149	AP								
150	AP	**REVENUES AND BILLING DETERMINANTS**							
151	AP								
152	AP	Base Rate Sales Revenue	SALESREV	1.000000	0.492880	0.370271	0.000287	0.057649	0.078913
153	AP								
154	AP	Residential Service Gas	REVRSG	1.000000	0.560217	0.298193	0.000000	0.068386	0.073204
155	AP	General Service Gas	REVGSG	1.000000	0.450895	0.359664	0.000000	0.035853	0.153588
156	AP	Large Volume Service Gas	REVLVG	1.000000	0.226634	0.709048	0.000000	0.018732	0.045586
157	AP	Street Light Gas	REVSLG	1.000000	0.126861	0.156490	0.710964	0.005643	0.000043
158	AP	Firm Transportation Gas Service	REVTSGF	1.000000	0.057327	0.675057	0.000000	0.242875	0.024742
159	AP								
160	AP	Total Rev Req @ desired ROR	REVREQ	1.000000	0.492880	0.370271	0.000287	0.057649	0.078913
161	AP								
162	AP	**PRESENT REVENUES FROM SALES INPUT**							
163	AP	Total Sales of Gas Revenue Requirement		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
164	AP	Sales of Gas Revenues - Rates		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
165	AP	Sales of Gas Revenues - Other		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
2	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
3	ADA								
4	ADA	**Account 904 - Uncollectible Accounts**							
5	ADA	Residential Service Gas	REVRSG	991,282,164	555,333,136	295,593,534	0	67,789,982	72,565,512
6	ADA	General Service Gas	REVGSG	175,543,177	79,151,593	63,136,630	0	6,293,710	26,961,245
7	ADA	Large Volume Service Gas	REVLVG	210,026,237	47,599,123	148,918,700	0	3,934,158	9,574,256
8	ADA	Street Light Gas	REVSLG	559,485	70,977	87,554	397,774	3,157	24
9	ADA	Firm Transportation Gas Service	REVTSGF	7,477,232	428,644	5,047,555	0	1,816,030	185,003
10	ADA								
11	ADA	Total 904-Uncollectible	EXP_904	1,384,328,810	682,512,496	512,696,418	0	79,833,880	109,286,016
12	ADA								
13	ADA	Total 904-Uncollectible	EXP_904	1.000000	0.493028	0.370357		0.057670	0.078945
14	ADA								
15	ADA	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0
16	ADA								
17	ADA	**Rev Req (cal) to Customers Late Payment fees**							
18	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
19	ADA	General Service Gas	REVGSG	175,543,177	79,151,593	63,136,630	0	6,293,710	26,961,245
20	ADA	Large Volume Service Gas	REVLVG	210,026,237	47,599,123	148,918,700	0	3,934,158	9,574,256
21	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
22	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
23	ADA								
24	ADA	Total Late Payment Fees	REVLATEP	385,569,414	126,750,716	212,055,330	0	10,227,868	36,535,501
25	ADA								
26	ADA	Total Late Payment Fees	REVLATEP	1.000000	0.328736	0.549980		0.026527	0.094757
27	ADA								
28	ADA	**ALLOCATED DIRECT ASSIGNMENTS**							
29	ADA	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**							
30	ADA								
31	ADA	**AVAILABLE**							
32	ADA	Residential Service Gas	REVRSG	0	0	0	0	0	0
33	ADA	General Service Gas	REVGSG	0	0	0	0	0	0
34	ADA	Large Volume Service Gas	REVLVG	0	0	0	0	0	0
35	ADA	Street Light Gas	REVSLG	0	0	0	0	0	0
36	ADA	Firm Transportation Gas Service	REVTSGF	0	0	0	0	0	0
37	ADA								
38	ADA	Total Available	REVAVAIL	0	0	0	0	0	0
39	ADA								
40	ADA	Total Available	REVAVAIL	0.0	0.0	0.0	0.0	0.0	0.0

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

LINE NO.	SUB-SCH NO.	DESCRIPTION	ALLOCATION BASIS	Total Company	Distribution Access	Distribution Delivery	Street Lighting	Customer Service	Measurement
				(1)	(2)	(3)	(4)	(5)	(6)
1	RRW	**REVENUE REQUIREMENTS**							
2	RRW								
3	RRW	PRESENT RATES							
4	RRW	----------							
5	RRW	RATE BASE		8,668,832,235	4,773,814,938	3,281,363,918	1,161,960	58,835,070	553,656,348
6	RRW	NET OPER INC (PRESENT RATES)		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839
7	RRW	RATE OF RETURN (PRES RATES)		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
8	RRW	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00
9	RRW	SALES REVENUE (PRE RATES)		1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
10	RRW	REVENUE PRES RATES $/THERM		$0.5330	$0.2627	$0.1974	$0.0002	$0.0307	$0.0421
11	RRW	REVENUE REQUIRED - $/MO/CUST		$60.93	$30.03	$22.56	$0.02	$3.51	$4.81
12	RRW								
13	RRW								
14	RRW	CLAIMED RATE OF RETURN							
15	RRW	----------							
16	RRW	CLAIMED RATE OF RETURN		7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
17	RRW	RETURN REQ FOR CLAIMED ROR		639,759,819	352,307,542	242,164,657	85,753	4,342,028	40,859,839
18	RRW	SALES REVENUE REQ CLAIMED ROR		1,384,888,295	682,583,473	512,783,972	397,774	79,837,037	109,286,039
19	RRW	REVENUE DEFICIENCY SALES REV		0	0	0	0	0	0
20	RRW	PERCENT INCREASE REQUIRED		0.0	0.0	0.0	0.0	0.0	0.0
21	RRW	ANNUAL BOOKED THERM SALES		2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838	2,598,285,838
22	RRW	SALES REV REQUIRED $/THERM		$0.5330	$0.2627	$0.1974	$0.0002	$0.0307	$0.0421
23	RRW	REVENUE DEFICIENCY $/THERM		0.0	0.0	0.0	0.0	0.0	0.0

Based on 12 months actual

PUBLIC SERVICE ELECTRIC & GAS COMPANY
2022 GAS COST OF SERVICE STUDY
12 MONTHS ENDING DECEMBER 31, 2022

line #	FUNCTIONAL SEGMENTS REV REQ	Total Company (1)	RSG (2)	GSG (3)	LVG (4)	SLG (5)	TSG-F (6)
1	Distribution Access	$682,583,473	$555,333,136	$79,151,593	$47,599,123	$70,977	$428,644
2	Distribution Delivery	$512,783,972	$295,593,534	$63,136,630	$148,918,700	$87,554	$5,047,555
3	Street Lighting	$397,774	0	0	0	$397,774	0
4	Customer Service	$79,837,037	$67,789,982	$6,293,710	$3,934,158	$3,157	$1,816,030
5	Measurement	$109,286,039	$72,565,512	$26,961,245	$9,574,256	$24	$185,003
6	Total	$1,384,888,295	$991,282,164	$175,543,177	$210,026,237	$559,485	$7,477,232

Service Charge Calculations

line #	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	Notes:
1			Average Distribution Increase =		36.935%					Schedule SS-G8 , page 1, line 4
	Rate Schedule	Distribution Access Rev Req (in $1,000)	Customer Service Rev Req (in $1,000)	Measurement Rev Req (in $1,000)	COS Indicated Total Rev Req (in $1,000)	# of Customers	Cost Based Monthly Service Charge ($/month)	Current Monthly Service Charge ($/month)	Proposed Limited Monthly Service Charge ($/month)	
2	RSG	631,482	78,576	82,625	792,684	1,712,253	$ 38.58	$ 8.08	$ 12.56	move to costs, limited @ 1.5 times overall avg Distribution % increase
3	GSG	87,627	7,196	29,853	124,676	140,296	$ 74.06	$ 18.97	$ 29.48	move to costs, limited @ 1.5 times overall avg Distribution % increase
4	LVG	53,934	4,740	10,864	69,538	19,537	$ 296.61	$ 168.50	$ 261.85	move to costs, limited @ 1.5 times overall avg Distribution % increase
5	TSG-F	429	1,816	185	2,430	64	$ 3,163.64	$ 902.42	$ 1,402.39	move to costs, limited @ 1.5 times overall avg Distribution % increase
6	TSG-NF							$ 902.42	$ 1,402.39	set equal to new TSG-F Service Charge
7	CIG							$ 199.11	$ 272.65	increase current @ average Distribution % increase
8	CSG							$ 902.42	$ 1,402.39	set equal to new TSG-F Service Charge
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Notes:		values for RSG, GSG & LVG for Cols 2, 3, & 4 from SS-G7, pg 2, lines 20, 23 & 24 values for TSG-F for Cols 2, 3 & 4 from SS-G7, pg 1, lines 1, 4 & 5			= (2) + (3) + (4)	RSG, GSG & LVG from SS-G7, page 2, line 1 TSG-F from COS workpapers	= Col 5 * 1000 / Col 6 / 12 rounded to $.01	SS-G11	based on methodology described	

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Proposed Rate Calculations

Actual results through: 10/31/2023

Schedule SS-TAC-1

($'s Unless Specified)

SUT Rate 6.625%

Line	Date(s)		Electric	Gas	Total	Source/Description
1	Sept24 - Dec25	Net Revenue Requirements	(188,652,303)	(256,978,518)	(445,630,821)	SS-2E/G, Col 26
2	Aug-24	(Over) / Under Recovered Balance	353,224	(13,018,165)	(12,664,941)	- SS-3E/G, Col 5
3	Aug-24	Cumulative Interest Exp / (Credit)	74,869	(136,068)	(61,199)	- SS-3E/G, Col 10
4	Sept24 - Dec25	Total Target Rate Revenue	(188,224,210)	(270,132,751)	(458,356,961)	ln 1 + ln 2 + ln 3
5	Sept24 - Dec25	Revenue at Proposed 2024 TAC rates	(45,101,391)	(122,531,548)	(167,632,940)	SS-6E/G, ln 19
6	Sept24 - Dec25	Proposed TAC Increase / (Decrease)	(143,122,819)	(147,601,203)	(290,724,022)	Ln 4 - ln 5
7	Sep24 - Aug25	Annualized Target Rate Revenue	(142,860,375)	(211,473,051)	(354,333,426)	SS-6E/G, ln 15
8	Sep24 - Aug25	Annualized Revenue at Proposed 2024 TAC rates	(34,225,047)	(95,774,969)	(130,000,016)	SS-6E/G, ln 17
9	Sep24 - Aug25	Annualized TAC Increase / (Decrease)	(108,635,328)	(115,698,082)	(224,333,410)	Ln 7 - ln 8

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT
Gas Net Revenue Requirement
$000

	1	2	3	4	5	6	7	8	9	10	11	12
	1. Return Historic ADIT											
	Unprotected Excess			Protected Excess			SHARE			Mixed Service Cost		
	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance	Beginning Balance	Amortization to Customers	Ending Balance
Jan-23	74,787	(5,651)	69,136	282,517	(618)	281,899	209,996	(1,544)	208,452	-	-	-
Feb-23	69,136	(5,651)	63,486	281,899	(618)	281,280	208,452	(1,544)	206,908	-	-	-
Mar-23	63,486	(10,813)	52,673	281,280	(397)	280,884	206,908	(2,955)	203,954	-	-	-
Apr-23	52,673	(3,940)	48,733	280,884	(291)	280,593	203,954	(1,077)	202,877	-	-	-
May-23	48,733	(3,669)	45,064	280,593	(271)	280,322	202,877	(1,003)	201,874	-	-	-
Jun-23	45,064	(5,746)	39,318	280,322	(424)	279,897	201,874	(1,570)	200,304	-	-	-
Jul-23	39,318	(7,305)	32,012	279,897	(539)	279,358	200,304	(1,996)	198,308	-	-	-
Aug-23	32,012	(6,499)	25,513	279,358	(480)	278,878	198,308	(1,776)	196,533	-	-	-
Sep-23	25,513	(3,551)	21,963	278,878	(262)	278,616	196,533	(970)	195,563	-	-	-
Oct-23	21,963	(3,987)	17,976	278,616	(294)	278,321	195,563	(1,089)	194,474	-	-	-
Nov-23	17,976	(5,318)	12,658	278,321	(393)	277,929	194,474	(1,453)	193,021	-	-	-
Dec-23	12,658	(5,680)	6,978	277,929	(420)	277,509	193,021	(1,553)	191,467	-	-	-
Jan-24	6,978	(935)	6,043	277,509	(994)	276,515	191,467	(5,132)	186,336	-	-	-
Feb-24	6,043	(718)	5,326	276,515	(763)	275,752	186,336	(3,937)	182,398	-	-	-
Mar-24	5,326	(623)	4,703	275,752	(662)	275,090	182,398	(3,419)	178,979	-	-	-
Apr-24	4,703	(406)	4,297	275,090	(431)	274,658	178,979	(2,225)	176,754	-	-	-
May-24	4,297	(378)	3,920	274,658	(401)	274,257	176,754	(2,072)	174,682	-	-	-
Jun-24	3,920	(591)	3,328	274,257	(629)	273,628	174,682	(3,245)	171,437	-	-	-
Jul-24	3,328	(752)	2,577	273,628	(799)	272,829	171,437	(4,125)	167,312	-	-	-
Aug-24	2,577	(669)	1,908	272,829	(711)	272,119	167,312	(3,669)	163,643	-	-	-
Sep-24	1,908	(365)	1,542	272,119	(388)	271,730	163,643	(2,005)	161,638	-	-	-
Oct-24	1,542	(410)	1,132	271,730	(436)	271,294	161,638	(2,251)	159,387	-	-	-
Nov-24	1,132	(547)	585	271,294	(582)	270,712	159,387	(3,003)	156,384	-	-	-
Dec-24	585	(585)	(0)	270,712	(622)	270,090	156,384	(3,210)	153,174	-	-	179,068
Jan-25	(0)	-	(0)	270,090	(915)	269,175	153,174	(5,132)	148,042	179,068	(10,721)	168,347
Feb-25	(0)	-	(0)	269,175	(702)	268,473	148,042	(3,937)	144,105	168,347	(8,226)	160,121
Mar-25	(0)	-	(0)	268,473	(610)	267,863	144,105	(3,419)	140,685	160,121	(7,143)	152,978
Apr-25	(0)	-	(0)	267,863	(397)	267,466	140,685	(2,225)	138,460	152,978	(4,649)	148,329
May-25	(0)	-	(0)	267,466	(370)	267,097	138,460	(2,072)	136,388	148,329	(4,329)	144,001
Jun-25	(0)	-	(0)	267,097	(579)	266,518	136,388	(3,245)	133,143	144,001	(6,779)	137,222
Jul-25	(0)	-	(0)	266,518	(736)	265,782	133,143	(4,125)	129,019	137,222	(8,617)	128,605
Aug-25	(0)	-	(0)	265,782	(654)	265,128	129,019	(3,669)	125,349	128,605	(7,666)	120,939
Sep-25	(0)	-	(0)	265,128	(358)	264,770	125,349	(2,005)	123,345	120,939	(4,188)	116,750
Oct-25	(0)	-	(0)	264,770	(401)	264,369	123,345	(2,251)	121,094	116,750	(4,702)	112,048
Nov-25	(0)	-	(0)	264,369	(536)	263,833	121,094	(3,003)	118,091	112,048	(6,274)	105,774
Dec-25	(0)	-	(0)	263,833	(573)	263,261	118,091	(3,210)	114,881	105,774	(6,706)	99,068
	= Prev Col 3 + Col 1 & 2 of "Balances" Wkst	Input	= Col 1 + Col 2	= Prev Col 6 + Col 3 of "Balances" Wkst	Input	= Col 4 + Col 5	= Prev Col 9 + Col 4 of "Balances" Wkst	Input	= Col 7 + Col 8	= Prev Col 12 + Col 11 of "Balances" Wkst	Input	= Col 10 + Col 11
Annual												
2023		(67,809)			(5,008)			(18,529)			-	
2024		(6,978)			(7,418)			(38,293)			-	
2025		-			(6,830)			(38,293)			(80,000)	
2026		-			(6,830)			(38,293)			(45,000)	
2027		-			(6,830)			(38,293)			(25,000)	
2028		-			(6,830)			(38,293)			(5,000)	
2029		-			(6,830)			(38,293)			(24,068)	

		Monthly After Tax WACC Post -2023 BRC:	0.587%		Monthly After Tax WACC Post -2023 BRC:	0.587%								
		Monthly After Tax WACC Pre-2023 BRC:	0.540%		Monthly After Tax WACC Pre-2023 BRC:	0.540%	Fed Tax Rate =	21.00%				Revenue Factor =	1.3947	
	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	1. Return Historic ADIT (cont.)				1a. Return Historic ADIT (cont.)				2. Current GSHARE Deduciton	2a. Current Mixed Srv & IDD	3. Other			
	Return on Rate Base				Return on Non Rate Base									
	Unprotected Excess ADIT Rate Base Related %	Rate Base Related Portion of Unprotected Excess ADIT Amortization to Customers	Cumulative Change in Rate Base	After-Tax Return on Cumulative Change in Rate Base	Beginning Non-Rate Base Related Portion of Unprotected Excess	Non-Rate Base Related Portion of Unprotected Excess ADIT Amortization to Customers	Ending Non-Rate Base Related Portion of Unprotected Excess	After-Tax Interest to Customers	Actual SHARE Deduction Flow-Through	Actual SHARE Deduction Flow-Through	IRS ESHARE Deduction Audit Adjust-ments	Other Major Tax Adjust-ments	Net Tax Adjustment	Net Revenue Requirement
Jan-23	79%	(4,481)	290,131	1,544	14,038	(1,170)	12,868	(73)	(4,156)	-	-	-	(10,497)	**(14,879)**
Feb-23	79%	(4,481)	296,676	1,585	12,868	(1,170)	11,698	(66)	(4,156)	-	-	-	(10,450)	**(14,812)**
Mar-23	79%	(8,574)	302,713	1,619	11,698	(2,238)	9,460	(57)	(4,225)	-	-	(3)	(16,830)	**(23,854)**
Apr-23	79%	(3,125)	309,019	1,652	9,460	(816)	8,644	(49)	(2,234)	-	-	(5)	(5,943)	**(8,424)**
May-23	79%	(2,909)	315,290	1,686	8,644	(760)	7,884	(45)	(2,080)	-	-	(3)	(5,383)	**(7,630)**
Jun-23	79%	(4,556)	321,526	1,720	7,884	(1,190)	6,695	(39)	(3,257)	-	-	(2)	(9,319)	**(13,209)**
Jul-23	79%	(5,792)	327,727	1,754	6,695	(1,514)	5,181	(32)	(4,141)	-	-	(3)	(12,262)	**(17,381)**
Aug-23	79%	(5,152)	333,893	1,787	5,181	(1,346)	3,835	(24)	(3,684)	-	-	(4)	(10,679)	**(15,137)**
Sep-23	79%	(2,815)	340,024	1,820	3,835	(736)	3,099	(19)	(2,013)	-	-	(3)	(4,997)	**(7,083)**
Oct-23	79%	(3,161)	346,120	1,853	3,099	(826)	2,273	(15)	(2,260)	-	-	(1)	(5,792)	**(8,210)**
Nov-23	79%	(4,217)	352,182	1,886	2,273	(1,101)	1,172	(9)	(3,015)	-	-	(0)	(8,301)	**(11,766)**
Dec-23	79%	(4,508)	358,208	1,919	1,172	(1,172)	-	(3)	(3,223)	-	-	0	(8,960)	**(12,700)**
Jan-24	100%	(935)	365,186	1,954	-	-	-	-	(3,695)	-	-	-	(8,802)	**(12,476)**
Feb-24	100%	(718)	369,478	1,984	-	-	-	-	(2,835)	-	-	-	(6,268)	**(8,884)**
Mar-24	100%	(623)	373,717	2,008	-	-	-	-	(2,462)	-	-	-	(5,159)	**(7,312)**
Apr-24	100%	(406)	377,905	2,030	-	-	-	-	(1,602)	-	-	-	(2,633)	**(3,733)**
May-24	100%	(378)	382,041	2,053	-	-	-	-	(1,492)	-	-	-	(2,290)	**(3,246)**
Jun-24	100%	(591)	386,126	2,075	-	-	-	-	(2,336)	-	-	-	(4,726)	**(6,699)**
Jul-24	100%	(752)	390,158	2,097	-	-	-	-	(2,970)	-	-	-	(6,548)	**(9,281)**
Aug-24	100%	(669)	394,139	2,119	-	-	-	-	(2,642)	-	-	-	(5,572)	**(7,898)**
Sep-24	100%	(365)	15,248	1,203	-	-	-	-	(1,443)	-	-	-	(2,999)	**(4,183)**
Oct-24	100%	(410)	19,125	101	-	-	-	-	(1,620)	-	-	-	(4,617)	**(6,439)**
Nov-24	100%	(547)	22,952	124	-	-	-	-	(2,162)	-	-	-	(6,170)	**(8,606)**
Dec-24	100%	(585)	26,726	146	-	-	-	-	(2,311)	-	-	-	(6,582)	**(9,180)**
Jan-25	0%	-	47,429	218	-	-	-	-	(3,216)	(1,206)	-	-	(20,973)	**(29,250)**
Feb-25	0%	-	60,183	316	-	-	-	-	(2,468)	(925)	-	-	(15,943)	**(22,235)**
Mar-25	0%	-	71,206	386	-	-	-	-	(2,143)	(804)	-	-	(13,733)	**(19,153)**
Apr-25	0%	-	78,348	439	-	-	-	-	(1,395)	(523)	-	-	(8,749)	**(12,202)**
May-25	0%	-	84,966	480	-	-	-	-	(1,299)	(487)	-	-	(8,076)	**(11,263)**
Jun-25	0%	-	95,283	529	-	-	-	-	(2,034)	(763)	-	-	(12,870)	**(17,949)**
Jul-25	0%	-	108,335	598	-	-	-	-	(2,585)	(969)	-	-	(16,434)	**(22,921)**
Aug-25	0%	-	119,891	670	-	-	-	-	(2,300)	(862)	-	-	(14,481)	**(20,197)**
Sep-25	0%	-	126,175	723	-	-	-	-	(1,256)	(471)	-	-	(7,556)	**(10,538)**
Oct-25	0%	-	133,197	762	-	-	-	-	(1,411)	(529)	-	-	(8,532)	**(11,900)**
Nov-25	0%	-	142,520	810	-	-	-	-	(1,882)	(706)	-	-	(11,590)	**(16,165)**
Dec-25	0%	-	152,438	866	-	-	-	-	(2,012)	(754)	-	-	(12,389)	**(17,279)**
	= Col 14 / Col 2	**Input**	**See "RateBase-G", Col 9**	**= (Prev Col 15 + Col 15) / 2 * Monthly AT WACC**	**Previous Col 19 + Col 1 of "Balances" Wkst**	**Input**	**= (Prev Col 17 - Col 18)**	**= (Prev Col 19 + Col 19) / 2 * Monthly AT WACC**	**= - (Col 21) * Fed Tax Rate**	**= - (Col 22) * Fed Tax Rate**	**Input**	**Input**	**= Col 2 + Col 5 + Col 8 + Col 11 + Col 16 + Col 20+ Col 21+ Col 22 + Col 24**	**= Col 25 * Rev Fct**
Annual														
2023				20,827		(14,038)		(431)	(38,441)	-	-	(24)	(109,415)	**(155,084)**
2024				17,893		-		-	(27,569)	-	-	-	(62,367)	**(87,936)**
2025				6,798		-		-	(24,000)	(9,000)	-	-	(151,325)	**(211,053)**
2026				14,297		-		-	(24,000)	(9,000)	-	-	(108,826)	**(151,779)**
2027				19,895		-		-	(24,000)	(9,000)	-	-	(83,228)	**(116,078)**
2028				24,082		-		-	(24,000)	(9,000)	-	-	(59,041)	**(82,344)**
2029				28,239		-		-	(24,000)	(9,000)	-	-	(73,952)	**(103,141)**

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT 10/31/2023 **Exhibit P-9**

Gas Over/(Under) Calculation Schedule SS-TAC-3G

Reflects a tax rate of 28.11%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Monthly Calculations	Over / (Under) Recovery Beginning Balance	Gas Revenues	Revenue Requirement Excluding WACC Cost	Over / (Under) Recovery	Over / (Under) Recovery Ending Balance	Over / (Under) Average Monthly Balance	Interest Rate (Annualized)	Interest On Over / (Under) Average Monthly Balance	Interest Roll-In	Cumulative Interest
Jan-23	(36,306,427)	(13,096,988)	(14,878,963)	1,781,975	(34,524,452)	(35,415,440)	0.16%	(3,395)	-	(27,117)
Feb-23	(34,524,452)	(13,235,538)	(14,812,316)	1,576,779	(32,947,674)	(33,736,063)	4.64%	(93,778)	-	(120,895)
Mar-23	(32,947,674)	(12,211,930)	(23,854,270)	11,642,340	(21,305,333)	(27,126,504)	4.78%	(77,680)	-	(198,575)
Apr-23	(21,305,333)	(5,842,578)	(8,423,563)	2,580,985	(18,724,349)	(20,014,841)	5.32%	(63,790)	-	(262,365)
May-23	(18,724,349)	(3,871,963)	(7,630,464)	3,758,501	(14,965,848)	(16,845,098)	5.32%	(53,687)	-	(316,052)
Jun-23	(14,965,848)	(2,577,268)	(13,208,659)	10,631,391	(4,334,457)	(9,650,152)	5.54%	(32,028)	-	(348,080)
Jul-23	(4,334,457)	(2,383,298)	(17,380,803)	14,997,505	10,663,049	3,164,296	5.25%	9,952	-	(338,128)
Aug-23	10,324,921	(3,132,098)	(15,136,558)	12,004,461	22,329,381	16,327,151	5.21%	50,990	(338,128)	50,990
Sep-23	22,329,381	(3,444,610)	(7,083,230)	3,638,620	25,968,001	24,148,691	5.21%	75,417	-	126,407
Oct-23	25,968,001	(5,826,423)	(8,209,529)	2,383,105	28,351,106	27,159,554	5.49%	89,246	-	215,652
Nov-23	28,351,106	(14,131,351)	(11,766,108)	(2,365,243)	25,985,864	27,168,485	5.49%	89,275	-	304,927
Dec-23	25,985,864	(21,558,482)	(12,699,799)	(8,858,683)	17,127,181	21,556,522	5.49%	70,834	-	375,761
Jan-24	17,502,942	(16,746,415)	(12,475,508)	(4,270,907)	13,232,035	15,367,489	5.49%	50,497	375,761	50,497
Feb-24	13,232,035	(14,869,824)	(8,884,303)	(5,985,521)	7,246,514	10,239,275	5.49%	33,646	-	84,143
Mar-24	7,246,514	(12,657,459)	(7,312,072)	(5,345,387)	1,901,127	4,573,821	5.49%	15,029	-	99,173
Apr-24	1,901,127	(7,317,203)	(3,732,609)	(3,584,594)	(1,683,467)	108,830	5.49%	358	-	99,530
May-24	(1,683,467)	(4,542,333)	(3,245,611)	(1,296,722)	(2,980,189)	(2,331,828)	5.49%	(7,662)	-	91,868
Jun-24	(2,980,189)	(2,798,615)	(6,698,800)	3,900,185	919,996	(1,030,097)	5.49%	(3,385)	-	88,483
Jul-24	919,996	(2,689,161)	(9,281,402)	6,592,241	7,512,236	4,216,116	5.49%	13,854	-	102,337
Aug-24	7,512,236	(2,391,935)	(7,897,863)	5,505,928	13,018,165	10,265,201	5.49%	33,731	-	136,068
Sep-24	13,154,233	(5,430,574)	(4,183,254)	(1,247,321)	11,906,912	12,530,573	5.49%	41,175	136,068	41,175
Oct-24	11,906,912	(10,468,514)	(6,438,771)	(4,029,743)	7,877,169	9,892,041	5.49%	32,505	-	73,680
Nov-24	7,877,169	(20,400,199)	(8,605,833)	(11,794,366)	(3,917,197)	1,979,986	5.49%	6,506	-	80,186
Dec-24	(3,917,197)	(30,574,307)	(9,180,255)	(21,394,052)	(25,311,249)	(14,614,223)	5.49%	(48,022)	-	32,164
Jan-25	(25,311,249)	(35,679,803)	(29,250,461)	(6,429,342)	(31,740,590)	(28,525,919)	5.49%	(93,735)	-	(61,571)
Feb-25	(31,740,590)	(31,681,550)	(22,235,143)	(9,446,407)	(41,186,998)	(36,463,794)	5.49%	(119,819)	-	(181,390)
Mar-25	(41,186,998)	(26,967,900)	(19,153,122)	(7,814,778)	(49,001,775)	(45,094,386)	5.49%	(148,179)	-	(329,569)
Apr-25	(49,001,775)	(15,589,986)	(12,202,113)	(3,387,873)	(52,389,648)	(50,695,712)	5.49%	(166,585)	-	(496,154)
May-25	(52,389,648)	(9,677,865)	(11,263,432)	1,585,567	(50,804,081)	(51,596,865)	5.49%	(169,546)	-	(665,699)
Jun-25	(50,804,081)	(5,962,710)	(17,949,419)	11,986,709	(38,817,372)	(44,810,727)	5.49%	(147,247)	-	(812,946)
Jul-25	(38,817,372)	(5,729,509)	(22,920,563)	17,191,054	(21,626,318)	(30,221,845)	5.49%	(99,308)	-	(912,254)
Aug-25	(21,626,318)	(5,096,241)	(20,197,103)	15,100,861	(6,525,457)	(14,075,888)	5.49%	(46,253)	-	(958,507)
Sep-25	(6,525,457)	(5,430,574)	(10,537,789)	5,107,215	(1,418,242)	(3,971,850)	5.49%	(13,051)	-	(971,559)
Oct-25	(1,418,242)	(10,468,514)	(11,900,210)	1,431,697	13,455	(702,394)	5.49%	(2,308)	-	(973,867)
Nov-25	13,455	(20,400,199)	(16,164,871)	(4,235,328)	(4,221,873)	(2,104,209)	5.49%	(6,914)	-	(980,781)
Dec-25	(4,221,873)	(30,574,307)	(17,279,092)	(13,295,215)	(17,517,088)	(10,869,480)	5.49%	(35,717)	-	(1,016,498)
	(Prior Col 5) + (Col 9)	Forecasted Therms * Proposed Rate	See Revenue Requirements Schedule for Details	Col 2 - Col 3	Col 1 + Col 4	(Col 1 + Col 5) / 2	Input	(Col 6 * (Col 7) / 12)*net of tax rate		Prior Month + Col 8 - Col 9

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Weighted Average Cost of Capital

Schedule SS-TAC-4

		Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After-Tax Weighted Cost
Long-Term Debt		45.53%	3.96%	1.80%	1.80%	1.30%
Customer Deposits		0.47%	0.87%	0.00%	0.00%	0.00%
Common Equity		54.00%	9.60%	5.18%	7.21%	5.18%
Total		100.00%		6.99%	9.02%	6.48%
Federal Tax Rate	21.00%					0.5402%
State Tax Rate	9.00%					
Fed Benefit of State Tax Deduction	-1.89%					
Effective Tax Rate	28.11%					

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Exhibit P-9

Revenue Factor

Schedule SS-TAC-5

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		0.0000
BPU Assessment Rate	0.2130	0.2130
Rate Counsel Assessment Rate	0.0502	0.0502
Income before State of NJ Bus. Tax	99.7367	99.7367
State of NJ Bus. Income Tax	8.9763	8.9763
Income Before Federal Income Taxes	90.7604	90.7604
Federal Income Taxes	19.0597	19.0597
Return	71.7007	71.7007
Revenue Factor	**1.3947**	**1.3947**

PSE&G 2024 REVISED TAX ADJUSTMENT CREDIT

Proposed Gas TAC Calculation

Exhibit P-9G

Schedule SS-TAC-6G

($'s Unless Specified)

Line		Current SUT Rate	6.625%								
						Gas					Source/Description
		RSG	GSG	LVG	SLG	TSG-F	TSG-NF	CIG	CSG	Total	
1	2024 Sales (Therms)	1,543,180	293,032	762,138	712	22,111	132,909	25,998	756,546	3,536,626	Input
2	Rate Class Allocation[1]	71.80%	11.57%	14.07%	0.05%	0.37%	1.12%	0.32%	0.70%	100.00%	CreditCalc-G TAC 2023
3	Revenue Requirements	(68,495,495)	(11,038,753)	(13,426,667)	(46,505)	(351,474)	(1,067,399)	(305,644)	(668,315)	(95,400,252)	CreditCalc-G TAC 2023
4	Proposed Rate w/o SUT ($/Therms)	(0.044386)	(0.037671)	(0.017617)	(0.065353)	(0.015896)	(0.008031)	(0.011756)	(0.000883)		CreditCalc-G TAC 2023
5	Public Notice Rate w/o SUT ($/Therms)	(0.044386)	(0.037671)	(0.017617)	(0.065353)	(0.015896)	(0.008031)	(0.011756)	(0.000883)		CreditCalc-G TAC 2023
6	Proposed Rate w/ SUT ($/Therms)	(0.047327)	(0.040167)	(0.018784)	(0.069683)	(0.016949)	(0.008563)	(0.012535)	(0.000941)		CreditCalc-G TAC 2023
7	Sep-24 to Dec-25 Sales (Therms)	1,986,353	375,704	966,546	943	29,527	171,391	35,305	976,289	4,542,056	
8	Rate Class Allocation	73.65%	11.87%	14.44%	0.05%					100.00%	Line 2 / Sum Line 2
9	Revenue Requirements	(198,939,789)	(32,061,191)	(38,996,700)	(135,071)	0	0	0	0	(270,132,751)	(SS-TAC-1, ln 4 [Gas]) * Line 8 * 1000
10	Proposed Rate w/o SUT ($/Therms)	(0.100153)	(0.085336)	(0.040346)	(0.143244)	0.000000	0.000000	0.000000	0.000000		(Line 7 / (Line 9 * 1,000)) [Rnd 6]
11	Public Notice Rate w/o SUT ($/Therms)										
12	Proposed Rate w/ SUT ($/Therms)	(0.106788)	(0.090990)	(0.043019)	(0.152734)	0.000000	0.000000	0.000000	0.000000		(Line 10 * (1 + SUT Rate)) [Rnd 6]
13	Jun-23 to May 24 Sales (Therms)	1,552,629	296,824	756,952	711	22,583	128,549	26,039	678,524	3,462,812	Input
14	Annulization Factor	78.16%	79.00%	78.32%	75.41%						(Line 7) / (Line 13)
15	Annualized Revenue Requirements	(155,500,976)	(25,329,864)	(30,540,358)	(101,853)					(211,473,051)	(Line 9) * (Line 14)
16	Filed Rates 2024	(0.044386)	(0.037671)	(0.017617)	(0.065353)	(0.015896)	(0.008031)	(0.011756)	(0.000883)		Line 4
17	Test Year Revenue Requirements at Filed Rates 2024	(68,915,008)	(11,181,651)	(13,335,231)	(46,469)	(358,979)	(1,032,379)	(306,116)	(599,137)	(95,774,969)	(Line 13 * Line 16)*1000
18	Annualized Change	(86,585,968)	(14,148,214)	(17,205,127)	(55,384)	358,979	1,032,379	306,116	599,137	(115,698,082)	Line 15 - Line 17
19	16 Month Revenue Requiremnets at Filed 2024 Rates	(88,166,245)	(14,153,137)	(17,027,632)	(61,624)	(469,362)	(1,376,441)	(415,043)	(862,063)	(122,531,548)	(Line 7 * Line 16)*1000

[1]Rate Class Allocation remains the same and stays in effect until the conclusion of the Company's next Base Rate Case

PSE&G Gas - Storm Recovery Charge
SRC Gas Rate Calculation

Schedule SS-SRC-1G

($'s - Unless noted)

Line No.	Calculation	Description	
1		Deferred Storm Cost Balance as of 9/1/24	3,745,180
2		Estimated Interest Expenses	296,724
3	=(1+2)/3 Years	Estimated Annual Revenue Requirement	1,347,301
4		Forecasted Annual Therms	2,749,512,775
5	=3/4	Proposed SRC (per therm excluding Sales & Use Tax)	0.000490
6	=5*(1+SUT%)	Proposed SRC (per therm Including Sales and Use Tax)	0.000522
7		Existing SRC (per therm Including Sales & Use Tax)	0.000000
8	=(5-7)*4	Storm Recovery Charge Increase / (Decrease)	1,347,261

PSE&G Gas - Storm Recovery Charge
Balance Over/(Under) and Interest Calculation

Schedule SS-SRC-2G

($'s - Unless noted)

	(1)	(2)	(3)	(4)	(5)	(6)
	Input	Input	Prior Col 6 - Col 1 + Col 2	Input	(Prior Col 6 + Col 3) / 2 * (Col 4 / 12)	Col 3 + Col 5
Month	SRC Revenue	Incremental Deferred Major Storm Expenses	Prior Month (Over)/Under Balance + Monthly Activity)	Annual Interest Rate	Interest Expense	SRC Balance - (Over)/Under
Aug-24						3,745,180
Sep-24	35,782	-	3,709,398	5.43%	16,854	3,726,252
Oct-24	67,758	-	3,658,493	5.43%	16,696	3,675,189
Nov-24	144,466	-	3,530,723	5.43%	16,291	3,547,015
Dec-24	201,279	-	3,345,736	5.43%	15,583	3,361,319
Jan-25	240,101	-	3,121,218	5.43%	14,656	3,135,874
Feb-25	211,283	-	2,924,592	5.43%	13,702	2,938,293
Mar-25	181,433	-	2,756,860	5.43%	12,876	2,769,736
Apr-25	104,854	-	2,664,881	5.43%	12,287	2,677,168
May-25	63,937	-	2,613,231	5.43%	11,961	2,625,192
Jun-25	41,017	-	2,584,175	5.43%	11,778	2,595,952
Jul-25	34,804	-	2,561,148	5.43%	11,659	2,572,807
Aug-25	34,294	-	2,538,513	5.43%	11,556	2,550,069
Sep-25	35,274	-	2,514,795	5.43%	11,451	2,526,246
Oct-25	67,765	-	2,458,481	5.43%	11,270	2,469,750
Nov-25	145,018	-	2,324,732	5.43%	10,840	2,335,572
Dec-25	199,730	-	2,135,842	5.43%	10,109	2,145,951
Jan-26	235,665	-	1,910,286	5.43%	9,170	1,919,456
Feb-26	207,959	-	1,711,498	5.43%	8,209	1,719,707
Mar-26	178,688	-	1,541,018	5.43%	7,372	1,548,390
Apr-26	102,902	-	1,445,488	5.43%	6,769	1,452,257
May-26	64,059	-	1,388,198	5.43%	6,422	1,394,620
Jun-26	40,112	-	1,354,508	5.43%	6,215	1,360,723
Jul-26	34,301	-	1,326,422	5.43%	6,075	1,332,497
Aug-26	33,555	-	1,298,942	5.43%	5,949	1,304,892
Sep-26	34,789	-	1,270,102	5.43%	5,822	1,275,924
Oct-26	66,996	-	1,208,928	5.43%	5,618	1,214,546
Nov-26	144,727	-	1,069,819	5.43%	5,165	1,074,983
Dec-26	196,255	-	878,728	5.43%	4,417	883,145
Jan-27	234,469	-	648,677	5.43%	3,463	652,140
Feb-27	206,055	-	446,085	5.43%	2,483	448,568
Mar-27	176,755	-	271,813	5.43%	1,629	273,441
Apr-27	102,255	-	171,187	5.43%	1,005	172,192
May-27	63,677	-	108,515	5.43%	635	109,150
Jun-27	39,088	-	70,062	5.43%	405	70,467
Jul-27	33,771	-	36,696	5.43%	242	36,938
Aug-27	32,848	-	4,090	5.43%	93	4,183

PSE&G Electric - Storm Recovery Charge
Over/(Under) Balance and Interest Calculation

Schedule SS-SRC-3G

($'s - Unless noted)

(1)	(2)	(3)
Input	Input	[Schedule SS-SRC-1G] Line 5 x Col 2
Rate Class	**Annual Therms**	**Annual Revenue**
RSG	1,529,513,058	749,461
GSG	289,505,767	141,858
LVG	757,509,975	371,180
SLG	678,864	333
TSG-F	20,993,520	10,287
TSG-NF	126,216,004	61,846
CIG	25,095,588	12,297
Total	2,749,512,775	1,347,261

PSE&G Societal Benefits Charge **Schedule SS-SBC-1**
Calculation of Cost Recovery - Gas Socal Programs
($000)

CALCULATION OF COST RECOVERY FACTOR

GAS **($000's)**

	PERIOD	**SOCIAL PROGRAMS**	
BEGINNING OVER/(UNDER) BALANCE INCLUDING INTEREST	8/31/2024	$0	
ACTUAL REVENUES	N/A	$0	
ACTUAL EXPENSES	N/A	$0	
INTEREST	N/A	$0	
OVER/(UNDER) BALANCE INCLUDING INTEREST	N/A	$0	
FORECAST REVENUES	N/A	$0	
FORECAST EXPENSES	N/A	$0	
INTEREST	N/A	$0	
OVER/(UNDER) BALANCE INCLUDING INTEREST	8/31/2024	$0	
BALANCE TO BE COLLECTED/(RETURNED) TO CUSTOMERS	8/31/2024	$0	
ESTIMATED EXPENSES TO BE COLLECTED	9/1/24 - 8/31/25	$41,979	
TOTAL TO BE COLLECTED/(RETURNED) TO CUSTOMERS	9/1/24 - 8/31/25	$41,979	
THERM SALES (9/1/2024-8/31/2025)		2,749,513	therm sales from current GAS SBC filing
DOLLAR PER THERM		$0.015268	
REVENUE IMPACT (9/1/2024-8/31/2025)		$41,979.5610	

CALCULATION OF REVENUE IMPACT ($000's)

	SOCIAL
REVISED RATE PER THERM	0.015268
CURRENT RATE PER THERM	0.000000
DIFFERENCE	0.015268
THERM SALES (000s) (03/01/23 - 2/29/24)	2,749,513
REVENUE IMPACT (9/01/24 - 8/31/25)	$41,980

Over / (Under) Balance

	estimate	estimate	estimate	estimate	estimate
SOCIAL PROGRAMS	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**
BEGINNING BALANCE	$0	($3,975)	($7,353)	($7,264)	($5,746)
REVENUES RECOVERY	$1,104	$2,090	$4,456	$6,208	$7,406
BAD DEBT EXPENSE	($5,079)	($5,468)	($4,368)	($4,690)	($4,090)
OVER/(UNDER) COLLECTED	($3,975)	($3,378)	$88	$1,518	$3,316
ACCUMULATED BALANCE	**($3,975)**	**($7,353)**	**($7,264)**	**($5,746)**	**($2,430)**
INTEREST CALCULATION:					
PRIOR BALANCE	$0	($3,975)	($7,353)	($7,264)	($5,746)
CURRENT BALANCE	($3,975)	($7,353)	($7,264)	($5,746)	($2,430)
(PRIOR BAL + CURRENT BAL)/2	($1,988)	($5,664)	($7,308)	($6,505)	($4,088)
INTEREST	($7)	($19)	($24)	($22)	($14)
INTEREST RATE	5.52%	5.52%	5.52%	5.52%	5.52%
CUMULATIVE INTEREST	**($7)**	**($25)**	**($49)**	**($71)**	**($85)**

Over / (Under) Balance

	estimate	estimate	estimate	estimate	estimate
SOCIAL PROGRAMS	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**
BEGINNING BALANCE	($2,430)	$2,177	$7,426	$8,270	$6,852
REVENUES RECOVERY	$6,517	$5,596	$3,234	$1,972	$1,265
BAD DEBT EXPENSE	($1,910)	($348)	($2,390)	($3,390)	($2,668)
OVER/(UNDER) COLLECTED	$4,607	$5,249	$844	($1,418)	($1,402)
ACCUMULATED BALANCE	**$2,177**	**$7,426**	**$8,270**	**$6,852**	**$5,450**
INTEREST CALCULATION:					
PRIOR BALANCE	($2,430)	$2,177	$7,426	$8,270	$6,852
CURRENT BALANCE	$2,177	$7,426	$8,270	$6,852	$5,450
(PRIOR BAL + CURRENT BAL)/2	($127)	$4,801	$7,848	$7,561	$6,151
INTEREST	($0)	$16	$26	$25	$20
INTEREST RATE	5.52%	5.52%	5.52%	5.52%	5.52%
CUMULATIVE INTEREST	**($85)**	**($69)**	**($43)**	**($18)**	**$2**

Over / (Under) Balance

Schedule SS-SBC-2

SOCIAL PROGRAMS	estimate **Jul-25**	estimate **Aug-25**
BEGINNING BALANCE	$5,450	$2,133
REVENUES RECOVERY	$1,074	$1,058
BAD DEBT EXPENSE	($4,390)	($3,190)
OVER/(UNDER) COLLECTED	($3,316)	($2,132)
ACCUMULATED BALANCE	**$2,135**	**$1**
INTEREST CALCULATION:		
PRIOR BALANCE	$5,450	$2,133
CURRENT BALANCE	$2,135	$1
(PRIOR BAL + CURRENT BAL)/2	$3,792	$1,067
INTEREST	$13	$4
INTEREST RATE	5.52%	5.52%
CUMULATIVE INTEREST	**$15**	**$18**

PSE&G Societal Benefits Charge
Revenue Change By Rate Schedule

Schedule SS-SBC-3

($'s - Unless noted)

(1) Input	(2) Input	(3) [Schedule SS-SRC-1G] Line 5 x Col 2
Rate Schedule	**Annual Therms**	**Annual Revenue**
RSG	1,529,513,058	23,352,605
GSG	289,505,767	4,420,174
LVG	757,509,975	11,565,662
SLG	678,864	10,365
TSG-F	20,993,520	320,529
TSG-NF	126,216,004	1,927,066
CIG	25,095,588	383,159
Total	2,749,512,775	41,979,561

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY

OF

AHMAD FARUQUI

PRINCIPAL EMERITUS

THE BRATTLE GROUP

December 29, 2023
P-10

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
AHMAD FARUQUI
PRINCIPAL EMERITUS - THE BRATTLE GROUP

Q. What is your name?

A. Ahmad Faruqui.

Q. What is your affiliation?

A. I am a Principal Emeritus with The Brattle Group.

Q. What are your qualifications?

A. I am an economist by training and have advised utilities, regulatory bodies, governments and legislative councils on all six continents. My CV is appended as Schedule AF-1.

Q. What is the topic of your testimony?

A. I am testifying in support of PSE&G's application for developing new time-of-use (TOU) rates for residential customers.

Q. What issues will you address in your testimony?

A. In my testimony, I provide the rationale for why TOU rates are more desirable than flat or inclining block rates, followed by a national overview of the state of TOU deployment. Then, I explain how PSE&G developed its TOU rates and discuss how it intends to deploy them.

Q. Why should rates be aligned with cost causation?

A. Cost causation is one of the fundamental tenets of rate design. It helps to promote economic efficiency and also promotes equity. It's mentioned in Professor Bonbright's widely cited text on public utility regulation.

Q. Why are TOU rates better aligned with cost causation than flat rates or inclining block rates?

A. Consumers don't consume the same amount of electricity around the clock. Electricity consumption varies by day, by month, and by season. In summer peaking utilities, air conditioning load creates a pattern of use that rises with temperature. Often, loads begin to rise in the afternoon and linger on into the evening hours. Load shapes are also driven by customer lifestyles. Since electricity cannot yet be stored in sufficient quantities, extra generation capacity has to be kept in reserve to meet peak loads. It stays idle most of the time and is expensive to install and operate. With flat rates, consumers have no incentive to conserve electricity during peak hours and to use more during off-peak hours. TOU rates provide customers an incentive to reduce peak load and to shift it to off-peak hours.

Q. What is the status of TOU rates in the US?

A. According to the US Energy Information Administration (EIA)[1], as of the year 2022, 380 utilities were offering time-varying rates including TOU rates and dynamic pricing rates to their residential customers. There were 13.1 million customers on these rates, representing 9% of all customers in the nation. However, it's worth noting that the average participant rate is skewed upwards by a few utilities. Nearly 60% of investor-owned utilities offering TOU rates have enrollment rates of less than 1% while some 15% of utilities have participation rates that exceed

[1] Annual Electric Power Industry Report, Form EIA-861, accessed at https://www.eia.gov/electricity/data/eia861/.

15%. Reasons for low enrollment at utilities include poor marketing of the TOU rate, inconvenient design (i.e., long peak period), and/or additional charges to cover the cost of an interval meter (where smart metering has not been deployed).

One of the primary reasons why TOU rate offerings are going up is the widespread deployment of smart meters. According to EIA[2], U.S. electric utilities had about 111 million advanced smart metering infrastructure (AMI) installations, representing 80% of all residential electric customers in 2021.

Q. How many pricing periods are typically to be found in a TOU rate?

A. About two-thirds of the utilities offer TOU rates with two periods and the remaining one-third offer TOU rates with three or more periods.

Q. What is the ratio of peak to off-peak prices in TOU rates?

A. According to the OpenEI database,[3] 85% of TOU rates have a price ratio greater than 2-to-1, with the mean value being 3-to-1. The mean differential between peak and off-peak rates is 12 cents/kWh. TOU rates with three periods have a similar price ratio as those with two period TOU rates and a similar differential.

Q. Based on your experience working with a wide range of utilities in the US and abroad and your review of the literature, why do utilities offer TOU rates?

A. In my view, the foremost reason why utilities offer TOU rates is to help customers manage their energy bills. Customers want choice and offering a TOU rate to them in addition to the existing rate (which could be flat or have an inclining block structure) accommodates that desire.

[2] US Energy Information Administration, accessed at https://www.eia.gov/tools/faqs/faq.php?id=108&t=3#:~:text=In%202021%2C%20U.S.%20electric%20utilities,electric%20meters%20were%20AMI%20meters.
[3] Utility Rate Database, accessed at https://openei.org/wiki/Utility_Rate_Database.

TOU rates encourage customers to shift their load away from the peak period and helps reduce costs for all customers over the long run. They also encourage off-peak usage which enhances the affordability of newly emerging, climate-friendly technologies, such as electric vehicles (EVs). Well-designed TOU rates represent a win-win situation for customers and their utilities.

Q. What is the typical duration of the peak period?

A. For a long time, utilities developed the duration of the peak period based on a review of prices in the wholesale market. The peak hours used to be 16 hours long and did not appeal to customers. Newer TOU rates, primarily designed to appeal to EV drivers, have much shorter peak periods, typically ranging from 4 to 6 hours. Peak periods used to cover the early afternoon hours, such as noon to 6 pm. Now they occur much later in the afternoon, and often range from 4 pm to 9 pm.

Q. How are the pricing periods developed?

A. Utilities typically develop pricing periods by reviewing recent data on annual hourly load shapes for system marginal costs and annual hourly load shapes for the system as a whole. Sometimes, they also review annual hourly load shapes for the residential class.

Q. How are prices developed by period?

A. Utilities typically develop them by reviewing hourly marginal energy costs and capacity costs for supply (capacity, energy, transmission and distribution). In this proceeding, PSE&G is only proposing changes in the distribution portion of rates. Since customers pay a single amount that includes generation, transmission and distribution, we have developed illustrative rates that include all these components. It's my understanding that the final version of TOU rates will be developed in future Basic Generation Service ("BGS") proceedings.

Q. Are system costs based on embedded or marginal costs?

A. In nearly every case that I am aware of, utilities base their rates on an embedded cost of service study. TOU rates are designed to be revenue-neutral for the class as a whole. Thus, a customer whose load shape resembles that of the class as a whole will see no change in their bill unless they change their load shape. If they lower their peak load and/or shift it to the off-peak period, they will realize bill savings. Peakier-than-average customers will see higher bills unless they reduce their peak load. Customers who are less peaky than the class average will realize immediate savings by choosing a TOU rate and if they lower their peak load, will realize even higher savings.

In a few cases, utilities also review a marginal cost of service study. However, these are only used to determine the ratio between peak and off-peak period charges. The absolute values are still based on an embedded cost of service study.[4]

Q. What are the different ways in which utilities deploy TOU rates to customers?

A. There are three modes of deployment: opt-in, opt-out and mandatory. Opt-in means the rate is offered to all customers. Any customer who wants to take it can sign up for it. Those customers who don't take the optional rate stay on their existing rate. Opt-out means that all customers are rolled over to the rate but any customer who does not want to stay on it can opt-out to another rate, which may be the prior rate or a new rate. Mandatory means that all customers are rolled over to the TOU rate and they have no choice. In Michigan, which has moved all customers to a default TOU rate, customers do have a choice to switch to other rates but they are also TOU rates.

[4] This method of developing rate is also called the equiproportional marginal cost method.

Q. How many TOU rates are deployed on an opt-in basis?

A. Most TOU deployments are on an opt-in basis.

Q. How many TOU rates are deployed on an opt-out basis?

A. In the US, California and Colorado have rolled out TOU rates as the default rate. In California, this was first done by a municipal utility, SMUD, which serves more than half a million customers in Sacramento and surrounding areas. It was then followed by all three large investor-owned utilities which serve 12 million customers. In Canada, the province of Ontario with some four million customers has rolled out TOU rates but they only apply to the energy portion of the rate.

Q. How many TOU rates are deployed on a mandatory basis?

A. The first utility to deploy TOU rates on a mandatory basis was Fort Collins, which serves nearly 69,000 customers. In Michigan, the two large investor-owned utilities, Consumers Energy and DTE, have deployed a TOU rate as the default and given customers a choice to opt-out to other TOU rates.

Q. Are pilots a pre-requisite for deploying TOU rates?

A. No. There have been scores of pilots around the US and many others around the globe. Utilities can safely proceed with offering opt-in TOU rates based on the experiences of other utilities, supplemented with insights gathered by conducting focus groups with their own customers. However, default and mandatory deployments should ideally be preceded by pilots. That has been the case in California, Colorado and Michigan.

Q. Is seasonal variation often found in TOU rates?

A. Yes, it's quite common, particularly in utilities where system load shapes vary across the seasons because of climatic factors, and this causes variation in the cost of service across seasons.

Q. What are the main features of well-designed TOU rates?

A. Well-designed TOU rates are customer-friendly and have short peak periods. They provide customers with an opportunity to save money by shifting their usage during the peak period to off-peak periods. Utilities provide videos on their web portal to educate customers on how they benefit by reducing peak loads and shifting energy consumption to the off-peak period. They often provide a bill calculator that allows customers to find the lowest cost rate that is consistent with their lifestyle. A single individual may have a different lifestyle than a young couple with no children or a family with young children or empty nesters.

Q. How can customers take advantage of TOU rates?

A. The penetration of EVs is growing fast. EVs are often the biggest load in a customer's house. Customers with EVs can set them to charge after midnight, when electricity costs are lowest. Customers with central air conditioning can precool their homes during the off-peak period by lowering their thermostat by a couple of degrees and raising it by a couple of degrees during the peak period. These days, most homes have programmable thermostats that make this a relatively easy task. Since central air conditioning is a big load in the house, this can yield substantial savings by itself. They can do their laundry during the off-peak hours. In addition, they can set the delay button on their dishwasher so it runs after midnight, which usually falls within the off-peak period.

Q. What utilities have successfully deployed opt-in TOU rates?

A. OGE in Oklahoma and APS and SRP in Arizona have successfully recruited large numbers of customers to TOU rates for years. They offer a choice of several TOU rates to their customers. In the past few years, utilities in Georgia, Missouri and New York have begun offering similarly well-designed rates to their customers on an opt-in basis. For additional details on the status of TOU rates in the US, please consult Schedule AF-2.

Q. Why is PSE&G planning to deploy TOU rates?

A. The primary purpose is to better reflect the cost of service. As noted earlier, this will promote economic efficiency and equity. There is a national trend toward TOU rates. This is being driven by a desire to combat climate change via electrification of buildings and transportation, and to manage the cost and operational challenges of that transition. EV deployment is rising fast. It's going to be potentially the biggest user of electricity in homes. Unless customers charge their EVs during off-peak and night time periods, they will end up creating a serious challenge to the grid. With TOU rates, they will be able to lower their charging costs and also reduce the strain on the grid. Of course, as noted earlier, smart meters are a pre-requisite to the widespread deployment of TOU rates.

Additionally, the Residential TOU Program meets PSE&G's commitment set forth in the BPU's CEF-EV Order to address rates for residential EV charging.[5]

Q. What specific TOU rates is PSE&G planning to deploy?

A. PSE&G is planning to offer two TOU rates to its residential customers. One TOU rate is going to be a two-period rate that modifies the existing Residential Load Management ("RLM")

[5] CEF-EV Order at 13 (Stipulation of Settlement, paragraph 33).

rate by shortening the peak period and enhancing the discount during the off-peak period. The other TOU rate will be a three-period TOU rate with a specially discounted night time rate to encourage night-time charging of EVs.

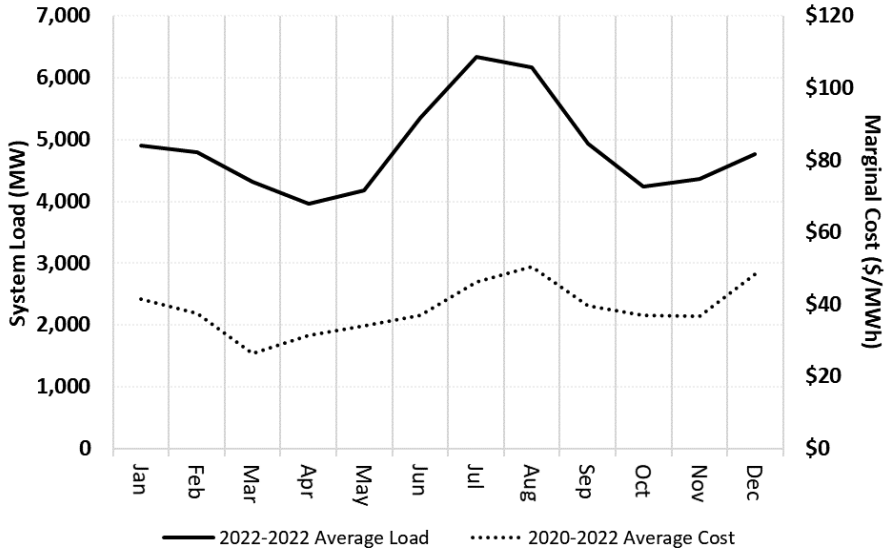
Q. Why is more than one TOU rate being offered?

A. To give customers choice, especially to those who drive EVs.

Q. How were they developed?

A. PSE&G is proposing to develop TOU rates focused on distribution costs in this proceeding. In a later filing, it will develop TOU rates focused on generation energy and capacity costs, transmission costs and all other costs. However, since customers pay a total bill, and not a separate distribution bill, in this testimony I have developed all-in TOU rates. We developed TOU pricing periods by reviewing data on hourly system load shapes, and hourly system marginal costs (equal to Day Ahead Locational Marginal Pricing ("LMPs")). These are summarized in Figure 1. System loads are shown on the vertical axis on the left and marginal costs on the vertical axis on the right.

Figure 1 Average System Load and Marginal Cost by Month (2020-2022)



The figure shows two distinct patterns across the year: winter and summer. Winter has eight months, which goes from October through December and January through May. Summer has four months, from June through September. This also aligns with PSE&G's gas season definition.

Figure 2 Typical Summer Weekday Profile (2020-2022)

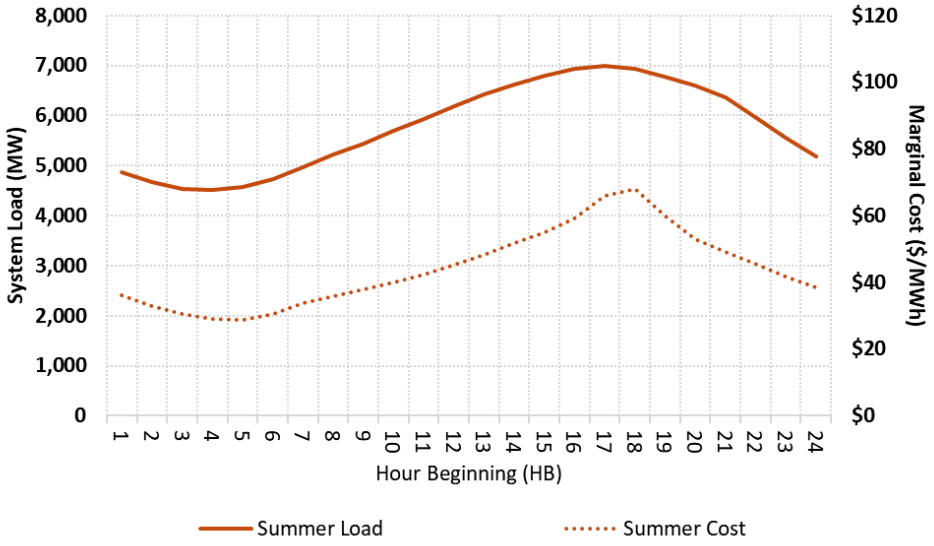
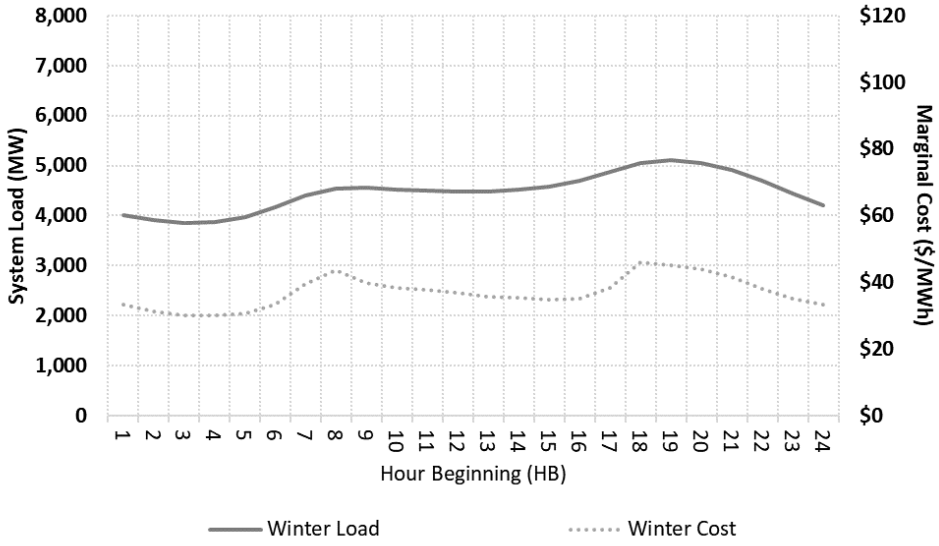


Figure 3 Typical Winter Weekday Profile (2020-2022)



Winter features bimodal peaks with pronounced evening peak while summer features one pronounced evening peak. For simplicity and better customer experience, we propose adopting the

same pricing period definitions for all seasons. The two-period TOU rate will have an on-peak time period that runs from 4 P.M. to 9 P.M. (EST) Monday through Friday, which is significantly shorter than the peak period in the existing TOU rate, and very much in line with the newer generation of TOU rates that are being offered in the US.[6] The three-period TOU rate will have the same on-peak period as the two-period TOU rate and will run from 4 P.M. to 9 P.M. (EST) Monday through Friday. In addition, it will have an off-peak period from 12 A.M. to 6 A.M. (EST) in all days that should appeal to EV drivers. All other hours shall constitute the Mid-Peak period.

Q. How did you design the two-period TOU rate?

A. The TOU rates were developed in close concert with Stephen Swetz of PSE&G and were designed to be revenue neutral with the RS rate class. As a starting point, Witness Swetz used PSE&G's embedded cost study for the Residential ("RS"), to develop TOU distribution rates. We designed generation rates to be revenue neutral to current the current RS default generation rates or Basic Generation Service ("BGS") RS rates. We used the Day-Ahead LMPs from PJM as a proxy for the marginal energy cost of generation. For other generation costs, we used costs that were used to develop BGS rates, then adjusted the results to ensure revenue neutrality. We designed transmission rates to be revenue neutral to the RS transmission rates but set rates to recover costs via certain TOU rate periods to better align with cost causation.

For the two-period TOU rate, we first calculated the summer and non-summer peak rates to reflect the generation, transmission, and distribution capacity and the generation energy costs. We allocated the remaining costs (net of revenue from peak hours and revenue from fixed

[6] The definition of current RLM on-peak period is 7 A.M. to 9 P.M. (EST) Monday through Friday during Daylight Savings Time. All other hours are considered as off-peak period.

charges) equally across the off-peak periods, solving for the corresponding rates to ensure revenue neutrality.

The current RS rate varies by season. It also has two tiers in it. Under PSE&G's rate proposal, the average residential customer on the RS rate would pay 22 cents/kWh in the summer and 17 cents/kWh in the winter months. This reflects an increase of 18% in summer and an increase of 7% in winter compared to the current RS rate. Both rates are shown in the figure below.

Figure 4 Summary of Current and Proposed RS Rate

		Current RS Rate		Proposed RS Rate	
		Summer	**Winter**	**Summer**	**Winter**
Generation ($/kWh)	0-600	$0.077023	$0.080531	$0.077023	$0.080531
	Over 600	$0.086772		$0.086772	
Distribution ($/kWh)	0-600	$0.047449	$0.035553	$0.081585	$0.047785
	Over 600	$0.051523		$0.085659	
Transmission ($k/kWh)		$0.061233	$0.061233	$0.061233	$0.061233
Average Total Rate ($/kWh)		**$0.187680**	**$0.160734**	**$0.221816**	**$0.171218**
Monthly Charge ($/Month)		$4.95		$8.05	

Figure 5 Summary of Proposed Two-Period TOU Rate

	Two Period TOU			
	Summer		**Winter**	
	On Peak	**Off Peak**	**On Peak**	**Off Peak**
Generation ($/kWh)	$0.127337	$0.065788	$0.131136	$0.072600
Transmission ($/kWh)	$0.139700	$0.052704	$0.069850	$0.052704
Distribution ($/kWh)	$0.209513	$0.037114	$0.153778	$0.037114
Final Rate ($/kWh)	**$0.476551**	**$0.155605**	**$0.354764**	**$0.162418**
Monthly Charge ($/Month)	$8.05			

Under PSE&G's rate proposal, under the two-period rate, the average residential customer would pay a rate of 48 cents/kWh during the peak period and a rate of 16 cents/kWh during the off-peak

period in the summer; in the winter, the corresponding values would be 35 cents/kWh during the peak period and a rate of 16 cents/kWh during the off-peak period.

Q. Why did you design a three-period TOU rate in addition to a two-period TOU rate?

A. The three-period TOU rate is primarily designed to appeal to PSE&G's customers that drive EVs but all residential customers would be eligible to sign up for it.

Q. How did you design the three-period TOU rates?

A. Our methodology is similar to that of the two-period TOU rate. Like the two-period TOU rate, the three-period TOU rate is also revenue neutral, meaning that it collects the same amount of revenue for the class, before any load shifting.

Figure 6 Summary of Proposed Three-Period TOU Rate

	Three Period TOU					
	Summer			Winter		
	On Peak	Mid Peak	Off Peak	On Peak	Mid Peak	Off Peak
Generation ($/kWh)	$0.127337	$0.070636	$0.048759	$0.131136	$0.075768	$0.063677
Transmission ($/kWh)	$0.139700	$0.069850	-	$0.069850	$0.069850	-
Distribution ($/kWh)	$0.209513	$0.042307	$0.021153	$0.153778	$0.042307	$0.021153
Final Rate ($/kWh)	**$0.476551**	**$0.182794**	**$0.069912**	**$0.354764**	**$0.187925**	**$0.084830**
Monthly Charge ($/Month)			$8.05			

Under the three-period rate, the average residential customer would pay a rate of 48 cents/kWh during the peak period, which is the same as the peak period price in the two-period TOU rate; a rate of 18 cents/kWh during the mid-peak period, and a rate of 7 cents/kWh during the off-peak period in the summer. In the winter, the corresponding values would be 35 cents/kWh during the peak period, 19 cents/kWh during the mid-peak period and 8 cents/kWh during the off-peak period. The figures below provide graphical illustrations of the rate.

Figure 7 Graphic Illustration of Two-Period TOU Rates (Summer)

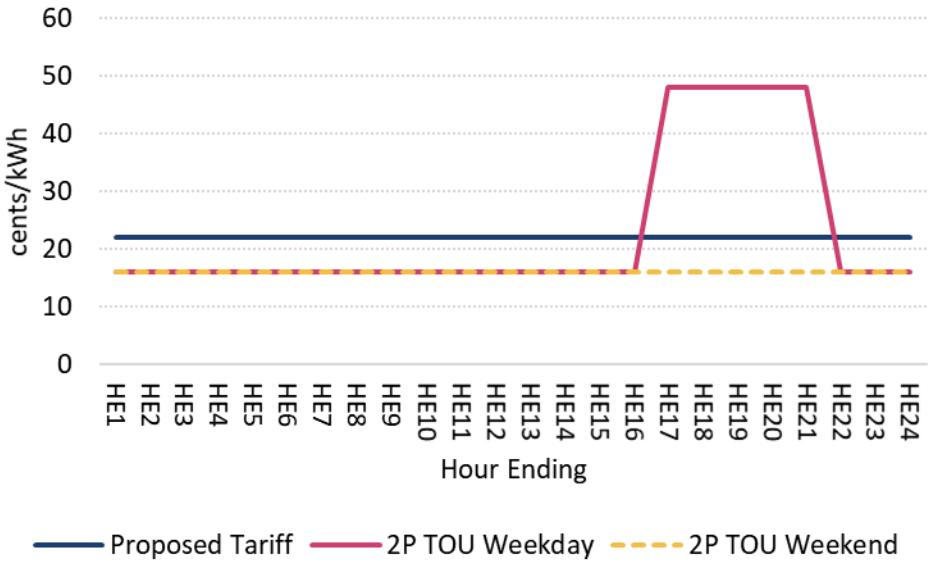
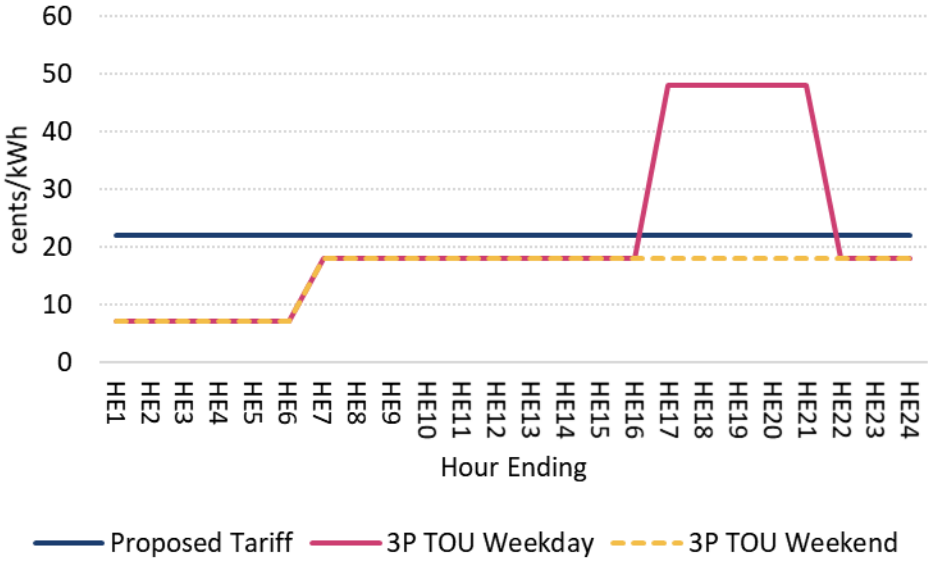


Figure 8 Graphic Illustration of Three-Period TOU Rates (Summer)



Q. How do the proposed TOU rates compare with those being offered by other utilities?

A. Structurally, they are quite similar. Since California has the largest number of customers on TOU rates, and since it also has the largest number of customers with EVs, I have compared PSE&G's rates with those being offered by PG&E, one of the two largest investor-owned utilities

in the state. It serves some 5 million electric customers in northern California and has a long history of offering TOU rates. It is also the utility which serves my personal residence.

Figure 9 shows the two-period TOU rates for the utilities and Figure 10 shows the three-period TOU rates. Structurally, the TOU rates are similar but since the average rate levels differ significantly for the two utilities (approximately 22 cents/kWh for PSE&G and approximately 38 cents/kWh for PG&E), PSE&G's customers are always going to be paying less per kWh than PG&E's customers.

Figure 9: Comparison of PSE&G's Two-Period TOU rate with PG&E's

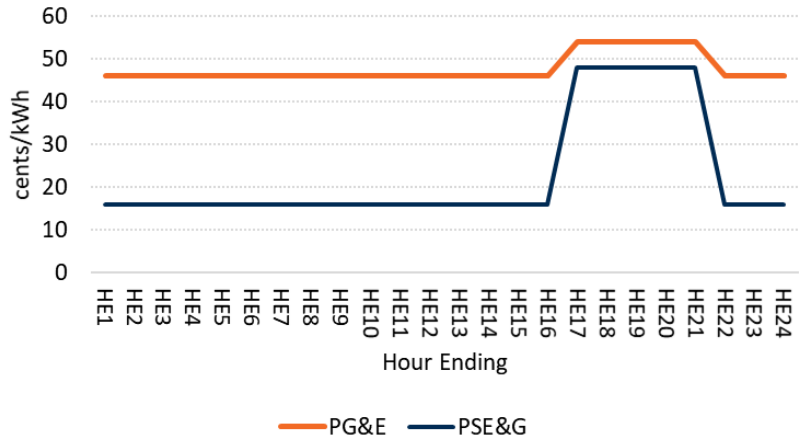
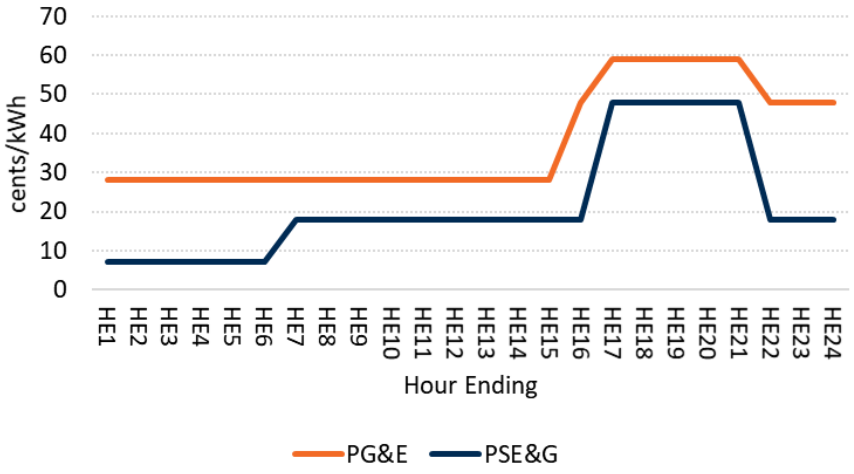


Figure 10: Comparison of PSE&G's Three-Period TOU rate with PG&E's



Q. Will the pricing periods in the TOU rates change at some point in the future?

A. Yes, they may change in the future if significant changes take place in the time pattern of system loads and system marginal energy and capacity costs. Such changes have occurred in utilities that have had TOU rates in place for decades. I have been on PG&E's TOU rates since the early 1990's. Back then, the on-peak period ran from noon to 6 pm. A decade or two later, it was changed and ran from 2 pm to 7 pm. Now it runs from 4 pm to 9 pm.

Q. Will the levels of the TOU rates change over time?

A. Yes, they may also change over time as significant changes take place in energy and capacity costs by time period.

Q. Are the rates designed to be revenue-neutral for the residential class?

A. Yes, they are. I have estimated the impact of the TOU rates on the average customer in a sample of 170 customers that was provided to me by PSE&G. The results are shown below in Figures 11 and 12, first for the two-period TOU rate, then for the three-period TOU rate. In the figures, positive numbers indicate bill savings and negative numbers indicate bill increases.

Figure 11 Average Bill Impact – Two-Period TOU

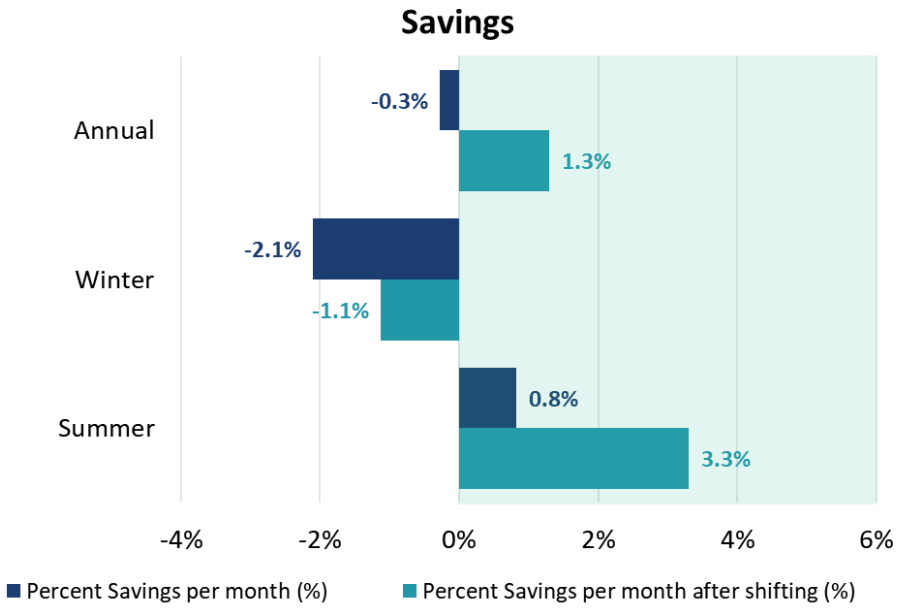
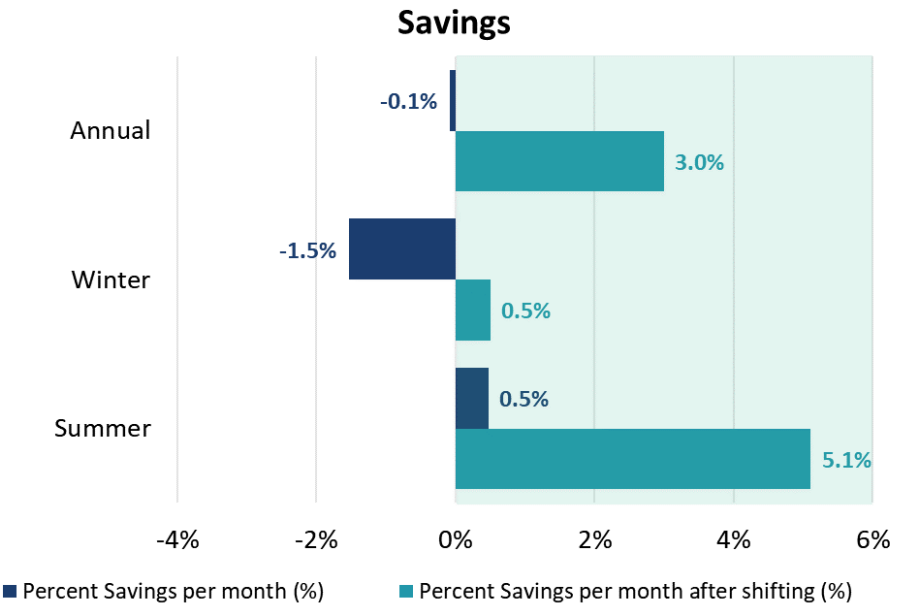


Figure 12 Average Bill Impact – Three-Period TOU



Q. What will be the likely impact of the TOU rates on customer bills?

A. Working with the sample of 170 customers, I estimated how each customer's bill will change if they were to move from the RS to each of the two TOU rates. For each rate, I rank

ordered the bill impacts by customer so that the biggest drop in bills occur to the left of the chart and the highest rise in bills occur to the right of the chart. This creates the "propeller charts" that are shown below in Figures 13 and 14. These charts show how the two TOU rates will affect customer bills before they engage in any load shifting. Approximately half of the customers save money simply by switching to the TOU rates, even in the absence of load shifting: 49% in the case of the two-period rate and 48% in the case of the three-period rate.

Figure 13 Monthly Bill Impact on Sample Customers (Two Period TOU, without load shifting)

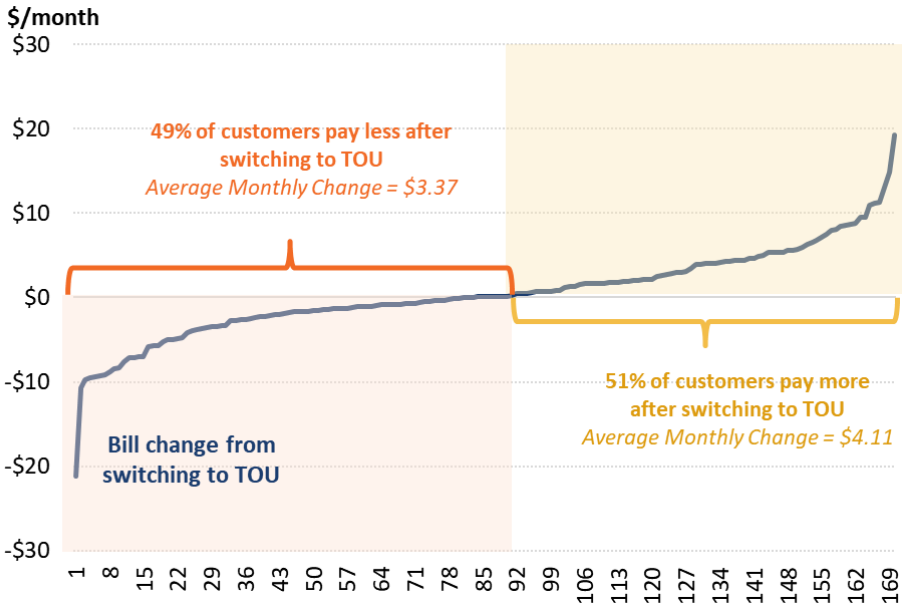
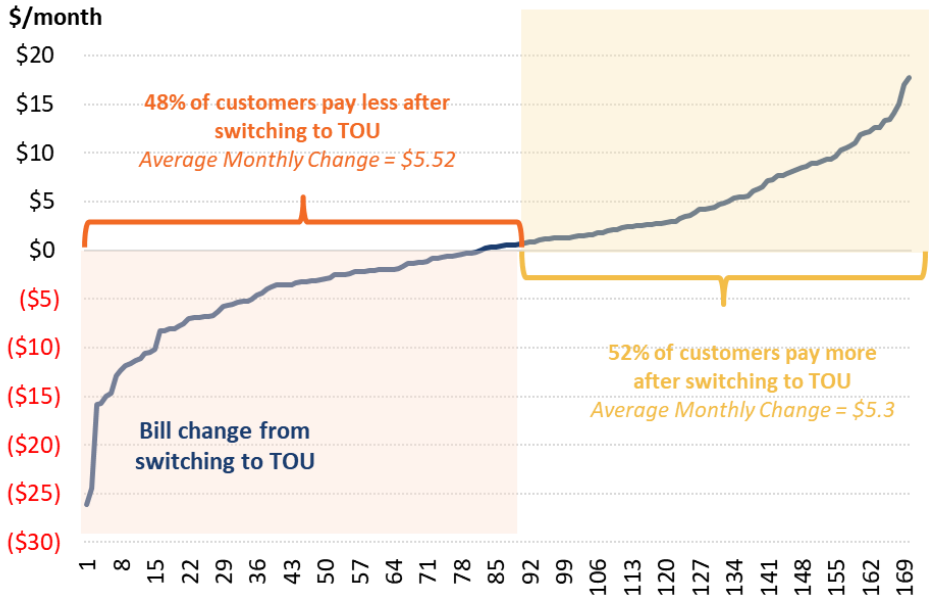


Figure 14 Monthly Bill Impact on Sample Customers (Three Period TOU, without load shifting)



Q. How strong is the incentive to shift loads away from the peak period?

A. Strong price signals exist for shifting load away from the peak period in both the two-period and the three-period TOU rates. For the two-period TOU rate, the peak to off-peak price ratio is about 3.1:1 to one in summer months, and 2.2:1 for non-summer months. The three-period TOU rate has an even stronger price signal, with a 6.8:1 price ratio during the summer months between on-peak and off-peak period.

Figure 15 Summary of the On-Peak to Off-Peak Ratio

		Residential 2P TOU	Residential 3P TOU
Summer			
On-Peak	$/kWh	$0.476551	$0.476551
Mid-Peak	$/kWh	-	$0.182794
Off-Peak	$/kWh	$0.155605	$0.069912
Winter			
On-Peak	$/kWh	$0.354764	$0.354764
Mid-Peak	$/kWh	-	$0.187925
Off-Peak	$/kWh	$0.162418	$0.084830
On-Peak : (Mid-Peak): Off-Peak Ratios			
Summer		3.1 :1	6.8 :2.6 :1
Winter		2.2 :1	4.2 :2.2 :1

Q. As a result of the price incentives offered by these two TOU rates, how much will customers lower their peak demand?

A. Customers will have a strong incentive to reduce their peak loads in response to these two TOU rates and to shift that load to the non-peak periods. Using the analytical charts in Arcturus, a Brattle database that contains a meta-analysis of results from more than 400 deployments of time-varying rates around the globe, I would expect to see the following pattern of results for the two TOU rates.[7] In the summer, the two-period TOU rate would induce a drop of 10% in peak load and a drop of 7% in the winter. As for the three-period TOU rate, in the summer it would induce a drop of 16% in peak load and a drop of 12% in the winter.

[7] For the purposes of this analysis, the model is developed based on 127 observations that are Time-of-Use rate and opt-in deployment from the Arcturus database. For background on Arcturus, please consult: https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf.

Figure 16 The Arc of Price Responsiveness – Two-Period TOU

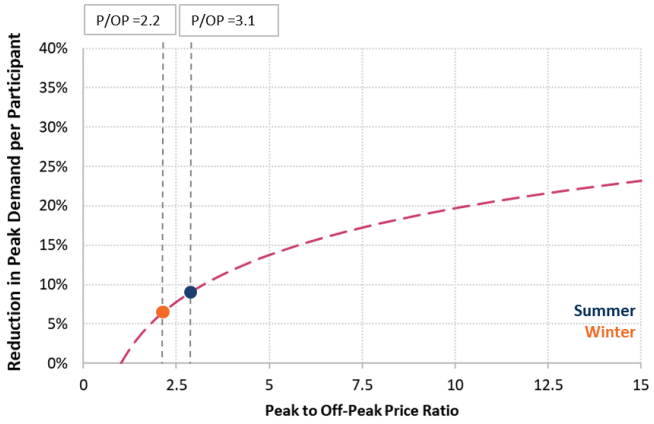
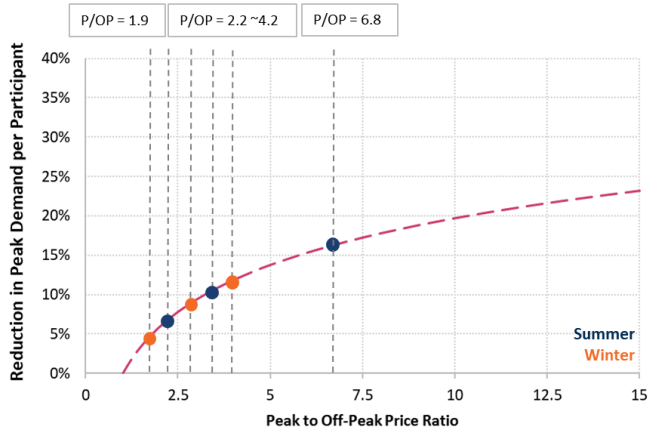


Figure 17 The Arc of Price Responsiveness – Three-Period TOU



Q. When customers respond to TOU rates by reducing their peak loads, will their bills go down?

A. Yes, I would expect them to go down as they shift their usage from a costlier period to the less costly off-peak period in the case of the two-period TOU rate and to the less-costlier mid-peak and off-peak periods in the case of the three-period TOU rate. The propeller charts which include the effect of load shifting away from the peak period are shown below. They show that a greater percentage of customers will see lower bills than the results shown in the previous figures which assumed no load shifting. For the two-period rate, 69% of customers save money, compared to

49% in the absence of load shifting. For the three-period rate, 80% save money, compared to 48% in the absence of load shifting.

Figure 18 Monthly Bill Impact on Sample Customers (Two Period TOU, with load shifting)

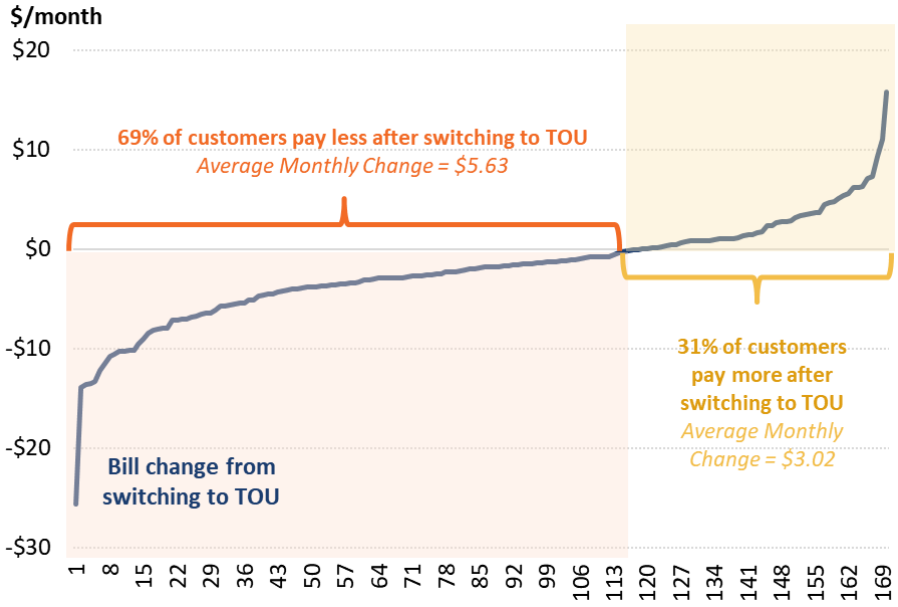
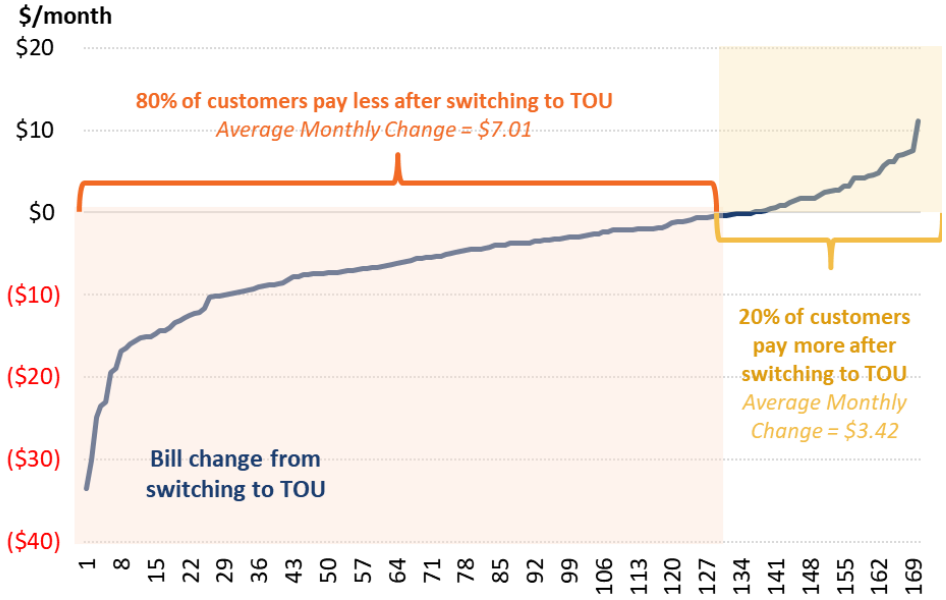


Figure 19 Monthly Bill Impact on Sample Customers (Three Period TOU, with load shifting)



Q. Will any customer be harmed by switching to TOU rates?

A. No. PSE&G will provide bill protection for the first year that a customer is on a TOU rate. They will not see a bill increase. If their bill goes down, they will get to keep the savings. Also, if they don't like the TOU rate for any reason, they will be able to opt-out of it. Additionally, PSE&G will provide ideas on its web portal to help customers modify their pattern of consuming energy to maximize their bill savings.

Q. What is your general assessment of the two TOU rates that PSE&G is proposing to offer its residential customers?

A. PSE&G's TOU rates recognize that customers have diverse tastes and preferences. Some customers want simplicity in their tariffs, others value comfort, while others want to closely monitor their usage and lower their bills by changing the way they consume energy. PSE&G will continue to offer its existing RS Rate Schedule as the default residential rate. The two TOU tariffs will be complementary to the RS Rate Schedule. They will appeal to customers who want to lower their bills by reducing their usage during the peak period and shifting it to the off-peak period.

Q. What is your opinion of the two-period TOU rate?

A. The rate features a discount of 17% compared to the existing tariff in the off-peak period, and a premium of 155% compared to the price in the on-peak period in summer. Customers who are able to shift energy consumption from the on-peak period (which is 5 hours long) to the off-period (which is 19 hours long) in the summer will save 67% on each kWh that is shifted in summer and 54% on each kWh in winter. In my opinion, this rate will appeal to those customers who are able to shift significant end use loads from the on-peak to the off-peak period. For example, they could load their dishes in the dishwasher and set its timer to start operating at 9 p.m. They could program their thermostat so it's a few degrees lower during the off-peak hours in the summer

months. If their normal setting is 74 degrees, they could raise it to 75 degrees during the on-peak hours and lower it to 73 degrees during the off-peak hours. The greater the differential in the temperature setting between the off-peak and on-peak periods, the more they will save.

Q. What is your opinion of the three-period TOU rate?

A. This rate features three pricing periods to provide a greater discount during the night time. Based on what I have observed in other jurisdictions where three-period TOU rates are being offered, it should appeal to customers who drive electric vehicles (EVs). They can simply set the timer in their cars to charge the battery during the off-peak hours. Most EVs can be fully charged in six hours and most drivers don't always fully charge their EVs. For each summer kWh shifted from the on-peak to the off-peak period, they will save 85%. For each summer kWh they shift from the on-peak to the mid-peak period, they will save 62%. For winter, the percentage savings are 76% and 47% from the on-peak to the off-peak and mid-peak period, respectively. In my opinion, this rate will appeal to customers who are seriously interested in saving money by moving significant portions of their load out of the on-peak period to the mid-peak and off-peak periods. This rate exemplifies the trends in modern rate designs: allowing customers to create significant savings opportunities by lowering demand when the grid is stressed. This would help PSE&G keep rates lower for customers in the long run by avoiding the need to invest in distribution infrastructure upgrades to meet higher peak demands.

Q. Is a shorter peak period likely to attract more customers than a longer peak period?

A. Yes. A shorter peak period is easier for customers to cope with than a longer peak period. Another advantage of the shorter peak period is that the price differential between on-peak and off-peak hours can be higher than with a longer peak period. Customers would save more for each kWh that is reduced and/or shifted to the off-peak period. In sum, a shorter on-peak period is easier

for customers to cope with and also more rewarding. Thus, I would expect it to attract more customers.

Q. Should the TOU rate structure stay constant or change over time?

A. Over time, I would expect system load shapes and costs to change, due to changes in the mix of generation resources and in the manner that customers use electricity, driven by the increasing penetration of EVs and distributed energy resources, such as solar panels and battery storage. As such changes occur, the rate structure should change which may involve changing the duration of the pricing periods as well as the prices within the periods. However, the rates should not be changed every year.

Q. What is the optimal frequency for changing rates?

A. In my view, rate structures and parameters should not be changed too frequently to prevent customer confusion and frustration. Ideally, the structure of the rates and its key parameters should be kept constant over a five-year period. Of course, the price levels in each period may change during this period to reflect changes in the cost of service, market prices and other factors. But the price ratios and period definitions should not be changed too frequently.

Q. Would you expect the proposed TOU rates to be well received by customers?

A. Yes, I would. Customers are likely to appreciate being given more choices to lower their bills by making slight modifications in their lifestyle. All of them will have an opportunity to try out the new TOU rates and see if they can lower their bills. They will have bill protection for the first year, and will only pay the lower of the TOU bill or the bill they would have paid with the standard rate. If are not able to lower their bill, they will have the option to get off the TOU rate at the end of their initial 12 month period.

Q. Does that conclude your testimony?

A. Yes.

Ahmad Faruqui

PRINCIPAL EMERITUS

San Francisco | +1.925.408.0149 | ahmadfaruqui@gmail.com

Dr. Faruqui is an energy economist whose consulting practice encompasses rate design, demand response, distributed energy resources, demand forecasting, decarbonization, electrification and energy efficiency and load flexibility.

In his career, Dr. Faruqui has advised some 150 clients in 12 countries on 5 continents and appeared before regulatory bodies, governments, and legislative councils in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, Egypt, FERC, Georgia, Illinois, Indiana, Iowa, Jamaica, Kansas, Kentucky, Michigan, Maryland, Minnesota, Missouri, Nevada, New Brunswick (Canada), Nova Scotia (Canada), Ohio, Oklahoma, Ontario (Canada), Pennsylvania, the Philippines, Saudi Arabia (ECRA), Texas, and Washington.

He has authored or coauthored more than 150 papers in peer-reviewed and trade journals and co-edited 5 books on industrial structural change, customer choice, and electricity pricing. His innovations have been cited in *Bloomberg*, *Businessweek*, *The Economist*, *Forbes*, and *National Geographic*, in addition to news outlets including the *Los Angeles Times*, *The New York Times*, *San Francisco Chronicle*, *San Jose Mercury News*, and *The Washington Post*. He has also appeared on Fox Business News and NPR.

He has taught economics at San Jose State University, the University of California, Davis, and the University of Karachi and delivered guest lectures at Carnegie Mellon, Harvard, Idaho, MIT, New York University, Northwestern, Rutgers, Stanford, UC Berkeley, and UC Davis. He has also given seminars on energy issues on 20 countries on 6 continents.

AREAS OF EXPERTISE

- Regulatory Economics, Finance, & Rates
- Electricity Wholesale Markets & Planning

EDUCATION

- **University of California, Davis**
  PhD in Economics
  MA in Agricultural Economics
- **University of Karachi (Karachi, Pakistan)**
  MA in Economics (Highest Honors)
  BA in Economics, with minors in Mathematics, & Statistics (Highest Honors)

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2006–Present)**
  Principal Emeritus (2021–Present)
  Principal (2006–2021)

EXPERT TESTIMONY

UNITED STATES

Arizona

- Rebuttal Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of Stacey Champion, et al., v Arizona Public Service Corporation, Docket No. E-01345A-18-0002, August 17, 2018.
- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of Stacey Champion, et al., v Arizona Public Service Corporation, Docket No. E-01345A-18-0002, July 31, 2018.
- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed To Develop Such Return, Docket No. E-01345A-16-0036, June 1, 2016.
- Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its

Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

- Testimony before the Board of Directors on behalf of Salt River Project, in the matter of "An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation," December 31, 2014.

Arkansas

- Direct Testimony before the Arkansas Public Service Commission on behalf of Entergy Arkansas, Inc., in the matter of Entergy Arkansas, Inc.'s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules, Docket No. 16-060-U, September 19, 2016.

California

- Prepared testimony before the California Public Utilities Commission on behalf of Bloom Energy Corporation, Application R.20-11-003, September 10, 2021.
- Testimony before the Board of Directors on behalf of SMUD, in the matter of "Encouraging Rooftop Solar without Creating Cross-subsidies," April 30, 2019.
- Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utility on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.
- Prepared testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, Summer 2010.
- Qualifications and prepared testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.
- Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

Colorado

- Rebuttal testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its

Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

- Direct testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

- Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use, Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

- Direct testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

Georgia

- Direct testimony before the State of Georgia Public Service Commission on behalf of Georgia Power Company, in the matter of Georgia Power Company's 2019 Base Rate Case, Docket No. 42516, June 28, 2019.

Idaho

- Rebuttal Testimony before the Idaho Public Utilities Commission on behalf of Idaho Power Company (Idaho Power), in the matter of the Application of Idaho Power Company for Authority to Establish New Schedules for Residential and Small General Service Customers with On-Site Generation, Case No. IPC-E-17-13, January 26, 2018.

Illinois

- Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

- Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.
- Rebuttal Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company in the matter of the Petition to Approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs, No. 09-0263, August 14, 2009.
- Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

- Direct testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

- Rebuttal testimony before the State Corporation Commission of the State of Kansas on behalf of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, December 04, 2020.
- Direct testimony before the State Corporation Commission of the State of Kansas on behalf of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, October 13, 2020.
- Rebuttal testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, July 3, 2018.
- Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Services, Docket No. 18-WSEE-328-RTS, February 1, 2018.

- Reply affidavit before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers, Docket No. 16-GIME-403-GIE, May 5, 2017.
- Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Louisiana

- Rebuttal testimony before the Council of the City of New Orleans on behalf of Entergy New Orleans, LLC, in the matter of Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, Docket No. UD-18-07, March 2019.
- Direct testimony before the Council for the City of New Orleans on behalf of Entergy New Orleans, LLC, in the matter of Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, Docket No. UD-18-07, July 2018.
- Direct testimony before the Louisiana Public Service Commission on behalf of Entergy Louisiana, LLC, in the matter of Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief in accordance with Louisiana Public Service Commission General Order dated September 22, 2009, R-29213, November 2016.
- Direct testimony before the Council of the City of New Orleans, on behalf of Entergy New Orleans, Inc., in the matter of the Application of Energy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief, October 2016.

Maryland

- Direct Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, April 19, 2016.

- Rebuttal Testimony before the Maryland Public Service Commission on behalf of Baltimore Gas and Electric Company in the matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates, Case No. 9406, March 4, 2016.
- Direct testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure. Case no. 9207, September 2009.
- Prepared direct testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

- Rebuttal testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.
- Direct testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Mississippi

- Direct testimony before the Mississippi Public Service Commission, on behalf of Entergy Mississippi, Inc., in the matter of Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements, EC-123-0082-00, November 2016.

Missouri

- Direct testimony before the Missouri Public Service Commission, on behalf of Union Electric Company d/b/a Ameren Missouri, in the matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service, ER-2019-0335, July 3, 2019.

Montana

- Rebuttal testimony before the Public Service Commission of the State of Montana on behalf of NorthWestern Energy, in the matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design, Docket No. D2018.2.12, April 2019.

- Prefiled direct testimony before the Public Service Commission of the State of Montana on behalf of NorthWestern Energy, in the matter of NorthWestern Energy's Application for Authority to Increase its Retail Electric Utility Service Rates and for Approval of its Electric Service Schedules and Rules, Docket No. D2018.2.12, September 28, 2018.

Nevada

- Prepared rebuttal testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.
- Prepared direct testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

- Direct testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Oklahoma

- Rebuttal Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, April 11, 2016.
- Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, December 18, 2015.
- Responsive Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Brandy L. Wreath, Director of the Public Utility Division, for Determination of the Calculation of Lost Net Revenues and Shared Savings Pursuant to the Demand Program Rider of Oklahoma Gas and Electric Company, Cause No. PUD 201500153, May 13, 2015.

Pennsylvania

- Direct testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case no. M-2009-2123944, January 11, 2011.

South Carolina

- Rebuttal Testimony before the Public Service Commission of South Carolina on behalf Duke Energy Carolinas, LLC and Duke Energy Progress, LLC in the matter Duke Energy Carolinas, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20, Febrauray 23, 2021.

Washington

- Pre-filed Direct Testimony before the Washington Utilities and Transportation Commission on Behalf of Puget Sound Energy, Dockets UE-22 and UG-22, January 31, 2022.
- Pre-filed Direct Testimony before the Washington Utilities and Transportation Commission on Behalf of Puget Sound Energy, Dockets UE-151871 and UG-151872, February 25, 2016.

CANADA

Alberta

- Virtual proceedings in front of the Alberta Utilities Commission, Application No. 24116-A001, Proceeding ID No. 24116. June 24, 2020.
- Information Response to Alberta Utilities Commission in Electric Distribution System Inquiry - Combined Module Proceedings ID 24116. June 17, 2020.

British Columbia

- Filed expert report, "Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review" with the British Columbia Utilities Commission (BCUC). February 22, 2022.

New Brunswick

- Presented before the New Brunswick Energy and Utilities Board in the Matter of the Stakeholder recommendations on rate design reform: Matter 357. May 12, 2020.

Nova Scotia

- Presented before the Nova Scotia Utility and Review Board in the Matter of The Public Utlities Act, R. S. N. S. 1989, c380, as amended. Time-Varying Pricing Tariff Application No. M09777. November 20, 2020.
- Presented before the Nova Scotia Utility and Review Board to provide an assessment of Nova Scotia Power, Inc.'s proposed Extra Large Industrial Active Demand Control (ELIADC) tariff for Port Hawkesbury Paper (PHP). February 2020.

REGULATORY APPEARANCES

Arkansas

- Presented before the Arkansas Public Service Commission, "The Emergence of Dynamic Pricing," at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

Delaware

- Presented before the Delaware Public Service Commission, "The Demand Response Impacts of PHI's Dynamic Pricing Program," Delaware, September 5, 2007.

Kansas

- Presented before the State Corporation Commission of the State of Kansas, "The Impact of Dynamic Pricing on Westar Energy," at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

- Presented before the Ohio Public Utilities Commission, "Dynamic Pricing for Residential and Small C&I Customers," at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

- Presented before the Public Utility Commission of Texas, "Direct Load Control of Residential Air Conditioners in Texas," at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

SELECTED CONSULTING EXPERIENCE

INNOVATIVE PRICING

- **Cost of service and tariff design study**. For a large electric utility in South-East Asia, Brattle provided consulting services for their cost of service and tariff design studies for incentive-based regulation, covering regulatory period 2 (2018–2020). Our work focused on understanding the cost drivers, reviewing the extent to which the current tariffs reflect the cost drivers, and developing new tariffs that better align with current and projected costs.
- **Impact analysis for TOU rates in Ontario.** Measured the impacts of a system-wide Time of Use (TOU) deployment in the province of Ontario, Canada, on behalf of the Ontario Power Authority. To account for the lack of a designated control group, Brattle created a quasi-experimental design that took advantage of differences in the timing of the TOU rollout.
- **Measurement and evaluation for in-home displays, home energy controllers, smart appliances, and alternative rates for Florida Power & Light (FPL).** Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy to fulfil the data reporting requirements of FPL's Smart Grid Investment Grant.
- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviewed the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real-time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discussed ways in which dynamic pricing could be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.
- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper included an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience was international regulators in regions that were exploring the potential benefits of smart metering and innovative pricing.

- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator, was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.
- **Pricing and technology pilot design and impact evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP). PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic pricing pilot design and impact evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact evaluation of a residential dynamic pricing experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.
- **Impact simulation of Ameren Illinois utilities' power smart pricing program.** Simulated the potential demand response of residential customers enrolled in real-time prices. The results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.
- **The case for dynamic pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.

- **Analyzed the economics of self-generation of steam.** Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for the probability of self-generation switching behavior, and a module for forecasting sales and peak demand.
- **Design and impact evaluation of the statewide pricing pilot: Three California utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.
- **Economics of dynamic pricing: Two California utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.
- **Economics of time-of-use pricing: A Pacific Northwest utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.
- **Economics of dynamic pricing options for mass-market customers - Client: A multi-state utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.
- **Real-time pricing in California - Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Cataloged the barriers to implementing real-time pricing in

California, and developed a program of research for mitigating the impacts of these barriers.

- **Market-based pricing of electricity - Client: A large Southern utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staff on the new methodologies.
- **Tools for electricity pricing - Client: Consortium of several U.S. and foreign utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.
- **Risk-based pricing - Client: Midwestern utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with the risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

DEMAND RESPONSE

- **Combined heat and power generation study.** Investigated the economic potential for combined heat and power and regulatory policies to unlock that potential in a Middle Eastern country.
- **National action plan for demand response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress.

- **National assessment of demand response potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress, as required by the Energy Independence and Security Act.
- **Demand response program review for Integrated Resource Plan development.** In response to legislation requiring the Connecticut utilities to jointly prepare a 10-year integrated resource plan, we conducted the analysis and helped prepare the plan. In coordination with the two leading utilities in the state, we conducted a detailed analysis of alternative resource solutions (both supply- and demand-side), drafted the report, and presented it to the Connecticut Energy Advisory Board. The analysis involved a detailed review and critique of the companies' proposed DR programs.
- **Integration of DR into wholesale energy markets.** Developed a whitepaper, "Fostering Economic Demand Response in the Midwest ISO," evaluating alternative approaches to efficiently integrating DR into its energy markets while encouraging increased participation. This work involved interviewing market participants and analyzing several approaches to economic DR regarding economic efficiency, participation rates, operational fit with other ISO rules, and susceptibility to state-level and ISO-level implementation barriers. This work involved an extensive survey of DR programs (qualification criteria, bidding rules, incorporation into market clearing software, measurement and verification, and settlement) in ISO/ Regional Transmission Organization (RTO) markets around the country. The project also required a detailed review of existing DR program tariffs for utilities in the RTO's service territory and development of a matrix for summarizing the various characteristics of these programs.
- **Integration of DR into resource adequacy constructs.** For the Midwest ISO, assisted in developing qualification criteria for DR as a capacity resource (we also developed estimates of likely future contributions of DR to resource adequacy, for use by their transmission planning group). For PJM, as part of our review of its capacity market, we developed recommendations on how to treat DR comparably to generation resources while accounting for the special attributes of DR. Our recommendations addressed product definition, auction rules, and penalty provisions. For the Connecticut utilities in their integrated resource planning, we evaluated future resource needs given various levels of demand response programs.
- **Evaluation of the demand response benefits of advanced metering infrastructure: Mid-Atlantic utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI.

The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.

- **Estimation of demand response impacts: Major California utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

SMART GRID STRATEGY

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by Brattle staff.
- **Cost-benefit analysis of the smart grid: Rocky mountain utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.
- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing the benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.
- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.

- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real-time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.
- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

DEMAND FORECASTING

- **Electricity sales and peak demand forecasting study.** For a large electric utility in South-East Asia, Brattle provided consulting services that involved assessing the performance of their load forecasting methodology and developing new models that provided more accurate forecasts.
- **Electricity consumption and maximum demand forecasting.** For a medium-sized utility in Asia-Pacific, Brattle provided consulting services on forecasting electricity consumption and maximum demand. Our work focused on analyzing drivers of growth in electricity sales, reviewed model performance, identified best practices and provided recommended approaches for analyzing trends in electricity sales and load forecasting.
- **Forecasting review.** Evaluated and critiqued the process conducted by an Australian utility company's electricity market forecasting, including the forecasting of electricity demand, supply, and price.
- **Comprehensive review of load forecasting methodology.** PJM Interconnection. Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed downward trend: Western utility.** Conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. Developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. Also developed a time

series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.

- **Analyzed why models are under-forecasting: Southwestern utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. Ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. demand forecast: Edison Electric Institute.** For the U.S. as a whole, developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. Subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed models for forecasting hourly loads: Merchant generation and trading company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.
- **Gas demand forecasting system - Client: A leading gas marketing and trading company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

DEMAND-SIDE MANAGEMENT

- **The economics of biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.
- **Assessment of demand-side management and rate design options: Large Middle Eastern electric utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.

- **Likely future impact of demand-side programs on carbon emissions - Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.
- **Sustaining energy efficiency services in a restructured market - Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that were likely to operate in a competitive market, such as third-party energy service companies (ESCO's) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.
- **Organizational assessments of capability for energy efficiency - Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.
- **Enhancing profitability through energy efficiency services - Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

ADVANCED TECHNOLOGY ASSESSMENT

- **Competitive energy and environmental technologies - Clients: Consortium of clients, led by Southern California Edison, included the Los Angeles Department of Water and Power and the California Energy Commission.** Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end-use application, and product size. Developed a user-friendly system for assessing

the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database of more than 200 end-use technologies and a model of customer decision making.

- **Market infrastructure of energy-efficient technologies - Client: EPRI**. Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers

PUBLICATIONS

ARTICLES & PAPERS

- "Did I make the right decision when I installed a solar+storage system at my house three years ago?" *Energy Central*, February 2, 2023. https://energycentral.com/c/cp/did-i-make-right-decision-when-i-installed-solarstorage-system-my-house-three
- "Have you ever seen a public agency act so brazenly against public opinion?" *Energy Central*, December 22, 2022. https://energycentral.com/c/um/have-you-ever-seen-government-agency-act-so-brazenly-against-public-opinion
- "Regulator could prove solar's NEMesis," *PV Magazine*, December 8, 2022. https://www.pv-magazine.com/2022/12/08/regulator-could-prove-solars-nemesis/.
- "Confessions of an Energy Economist: My career in energy policy revealed the power of politics," *Regulation*, Winter 2022-2023.
- "Ten lessons in rate design: a meditation," *The Electricity Journal*, December 2022, Volume 35, Issue 10. https://www.sciencedirect.com/science/article/abs/pii/S104061902200149X.
- "Recovering Network Costs in Rate Design: The State of Play in California," *Energy Central*, November 12, 2022. Recovering Network Costs in Rate Design: The State of Play in California | Energy Central.
- "Let's make rooftop solar panels paired with storage affordable for all," *Energy Central*, September 30, 2022. https://energycentral.com/c/cp/let%E2%80%99s-make-rooftop-solar-panels-paired-storage-affordable-all
- "Why did I reform my views on net energy metering (NEM)," *PV Magazine*, September 27, 2022. https://pv-magazine-usa.com/2022/09/27/why-did-i-reform-my-views-on-net-energy-metering-nem/

- "Can homes with solar+storage act as virtual power plants," *PV Magazine*, July 14, 2022. https://pv-magazine-usa.com/2022/07/14/can-homes-with-solarstorage-act-as-virtual-power-plants/
- "How should California price electricity for customers with rooftop solar panels?" With Jon Wellinghoff, *Energy Central*, June 9, 2022. https://energycentral.com/c/cp/how-should-california-price-electricity-customers-rooftop-solar-panels
- "The making of a clean energy consumer: Part three," *PV Magazine*, May 31, 2022. https://pv-magazine-usa.com/2022/05/27/the-making-of-a-clean-energy-prosumer-part-two/
- "The making of a clean energy prosumer: Part two," *PV Magazine*, May 27, 2022. https://pv-magazine-usa.com/2022/05/27/the-making-of-a-clean-energy-prosumer-part-two/
- "Guest Juice: Will Raising Electricity's Fixed Charges Incentivize Electrification?" *California Current*, May 26, 2022. https://cacurrent.com/guest-juice-will-raising-electricitys-fixed-charges-incentivize-electrification/
- "The making of a clean energy prosumer: Part one," *PV Magazine*, May 26, 2022. https://pv-magazine-usa.com/2022/05/26/the-making-of-a-clean-energy-prosumer-part-one/
- "Guest juice: Guidelines for better net metering; protecting all electricity customers and the climate," California Current, April 26, 2022, https://cacurrent.com/guest-juice-reforming-how-californias-utilities-charge-for-electricity-and-recover-costs-to-make-environmental-gains/
- "How to reform net energy metering the right way," *Utility Dive, March 2, 2022.* https://www.utilitydive.com/news/how-to-reform-net-energy-metering-the-right-way/619824/
- "Does dynamic pricing work in a winter-peaking climate? A case study of Hydro Quebec, with Frederic Pelletier, *The Electricity Journal*, Volume 35, Issue 2, March 2022. https://www.sciencedirect.com/science/article/abs/pii/S1040619022000069
- "The Battles over Net Energy Metering," with Agustin J. Ros and Gordon Kaiser, *Energy Regulation Quarterly*, July 2021, Volume 9, Issue 2. https://energyregulationquarterly.ca/articles/the-battles-over-net-energy-metering#sthash.1a5vWMny.dpbs
- "Did Griddy just write an obituary to dynamic pricing?" *Energy Central*, March 3, 2021. https://energycentral.com/c/gr/did-griddy-just-write-obituary-dynamic-pricing

- "Flexible Demand Side Grid Assets" by Matthew Schuerger, *Public Utilities Fortnightly*, December 2020. https://www.fortnightly.com/fortnightly/2020/12/flexible-demand-side-grid-assets
- "Resiliency in the West" by Ann Rendahl, *Public Utilities Fortnightly*, December 2020. https://www.fortnightly.com/fortnightly/2020/12/resiliency-west
- "The Road to Net Zero: Decorbonizing Household Consumption," by Clark Gellings and Ahmad Faruqui, *Public Utilities Fortnightly*, December 2020.
- "Bridging the Chasm Between Pilots and Full-scale Deployment of Time-of-Use Rates," with Sanem Sergici and Long Lam, *The Electricity Journal*, Volume 33, Issue 10, December 2020. https://www.sciencedirect.com/science/article/abs/pii/S1040619020301494
- "Factors Behind the Information of Community Choice Aggregation," with Mariko Geronimo Aydin, and John Higham, *The Electricity Journal*, Volume 33, Issue 10, December 2020. https://www.sciencedirect.com/science/article/abs/pii/S1040619020301548
- "Conceptual Discussion on a Potential Hidden Cross-Seasonal Storage: Cross-Seasonal Load Shift in Industrial Sectors," with Yingxia Yang and Jared DeFrain, *The Electricity Journal*, Volume 33, Issue 8, October 2020. https:/www.sciencedirect.com/science/article/pii/S104061902030138X?dgcid=author
- "Alberta Commission Chair Retires and Reflects on Regulatory Career: A conversation with Mark Kolesar," *Public Utilities Fortnightly,* Volume 158, September 2020. https:/www.fortnightly.com/fortnightly/2020/09/alberta-commission-chair-retires-and-reflects-regulatory-career
- "Avoiding Blackouts in California Through Load Flexibility," with Ryan Hledik, *Utility Dive*, September 2020. https://www.utilitydive.com/news/avoiding-blackouts-in-california-through-load-flexibility/585139/
- "Avoiding Blackouts," *Energy Central*, September 2020. https:/energycentral.com/c/em/avoiding-blackouts
- "The Coming Transformation of the Electricity Sector: A conversation with Amory Lovins," *The Electricity Journal*, Volume 33, Issue 7, August–September 2020. https://www.sciencedirect.com/science/article/pii/S1040619020301196
- "The Tariffs of Tomorrow: Innovations in Rate Designs," with Cecile Bourbonnais, *IEEE Power and Energy Magazine*, Volume 18, Issue 3, May–June 2020.

- "Time of Use Rates: An International Perspective," with Cecile Bourbonnais, Energy Regulation Quarterly, Volume 8, Issue 2, June 2020. https://www.energyregulationquarterly.ca/articles/time-of-use-rates-an-international-perspectives#sthash.tNurCwB7.IH1irft2.dpbs
- "Enhancing Rate Design Choices for Ontarians," Energy Central, June 2020. https://energycentral.com/c/em/enhancing-rate-design-choices-ontarians
- "6 Reasons Why California Needs to Deploy Dynamic Pricing by 2030," Utility Dive, May 2020. https://www.utilitydive.com/news/6-reasons-why-california-needs-to-deploy-dynamic-pricing-by-2030/578156/
- "Refocusing on the Consumer: Utilities regulation needs to prepare for the "prosumer" revolution," *Regulation*, March 2020. https://www.cato.org/sites/cato.org/files/2020-03/regv43n1-6.pdf
- "Why Dynamic Pricing Gets Back Seat in California: A dialogue with Commissioner Mike Peevey," *Public Utilities Fortnightly*, March 2020. https://www.fortnightly.com/fortnightly/2020/03/why-dynamic-pricing-gets-back-seat-california
- "Double Down on Efficiency," with Ralph Cavanagh, *Public Utilities Fortnightly*, December 2019.
- "A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors," with Ryan Hledik, Jürgen Weiss, Michael Hagerty and Long Lam, *American Association Bar*, November 13, 2019.
- "Quantifying Net Energy Metering Subsidies," with Sanem Sergici, Yingxia Yang, and Maria Castañer, *The Electricity Journal*, Volume 32, Issue 8, October 2019.
- "Reducing electricity prices and establishing electricity markets in China: Dos and don'ts," with Yingxia Yang, *The Electricity Journal*, Volume 32, Issue 8, October 2019.
- "2040: A Pricing Odyssey: How to price electricity when the grid goes 100 percent green," *Public Utilities Fortnightly*, June 1, 2019.
- "Expanding Customer Choices in a Renewable Energy Future," with Mariko Geronimo Aydin, *Leadership in Rate Design*, May–June 2019.
- "Emerging Landscape of Residential Rates for EVs – Creative design ahead," with Ryan Hledik and John Higham, *Public Utility Fortnightly*, May 2019.

https://www.fortnightly.com/fortnightly/2019/05/emerging-landscape-residential-rates-evs

- "The Transformative Power of Time-Varying Rates," *Energy Central*, March 8, 2019. https://energycentral.com/c/em/transformative-power-time-varying-rates
- "Transitioning to Modern Residential Rate Designs," with Lea Grausz and Cecile Bourbonnais, *Public Utility Fortnightly*, January 2019. https://www.fortnightly.com/fortnightly/2019/01/transitioning-modern-residential-rate-designs
- "Status of Residential Time-of-Use Rates in the U.S.," with Ryan Hledik and Cody Warner, *Public Utilities Fortnightly*, November 1, 2018. https://www.fortnightly.com/fortnightly/2018/11/status-residential-time-use-rates-us
- "Net Metering FAQ – Rate design and subsidies," with Steve Mitnick, *Public Utilities Fortnightly*, October 2018. https://www.fortnightly.com/fortnightly/2018/10/net-metering-faq
- "Rate Design 3.0 – Future of Rate Design," *Public Utilities Fortnightly*, May 2018. https://www.fortnightly.com/fortnightly/2018/05/rate-design-30
- Book Review – 'Modernizing America's Electricity Infrastructure' by Mason Wilrich, *Public Utilities Fortnightly*, May 2018. https://www.fortnightly.com/fortnightly/2018/05/mason-willrichs-modernizing-americas-electricity-infrastructure
- "Do Load Shapes of PV Customers Differ?" with Walter Graf, *Public Utilities Fortnightly*, February 2018. https://www.fortnightly.com/fortnightly/2018/02/do-load-shapes-pv-customers-differ
- " Fixed Charges in Electric Rate Design: A Survey," with Kirby Leyshon, *The Electricity Journal*, Volume 30, Issue 10, December, 2017, pp. 32-43. https://www.sciencedirect.com/science/article/abs/pii/S1040619017302828
- "Arcturus 2.0: A meta-analysis of time-varying rates for electricity," with Sanem Sergici and Cody Warner, *The Electricity Journal*, 30:10, December 2017, pp. 64-72. https://www.sciencedirect.com/science/article/pii/S1040619017302750
- "Moving Forward with Tariff Reform," with Mariko Geronimo Aydin, *Energy Regulation Quarterly*, Volume 5, Issue 4, December 2017. http://www.energyregulationquarterly.ca/articles/moving-forward-with-tariff-reform#sthash.ZADdmZ2h.D2l1yz9z.dpbs

- "Innovations in Pricing: Giving Customers What They Want," Electric Perspectives, September/October 2017.
- "Moving Forward with Electricity Tariff Reform," with Mariko Geronimo Aydin, *Regulation*, Fall 2017. https://object.cato.org/sites/cato.org/files/serials/files/regulation/2017/9/regulation-v40n3-5.pdf
- "Enhancing Customer-Centricity," with Henna Trewn, *Public Utilities Fortnightly*, August 2017. https://www.fortnightly.com/fortnightly/2017/08/enhancing-customer-centricity
- "The Public Benefits of Leasing Energy Efficient Equipment," with Neil Lessem and Henna Trewn, *The Electricity Journal*, 30:6, July 2017, pp. 8-16. http://www.sciencedirect.com/science/article/pii/S1040619017301513
- "Rethinking Customer Research in the Utility Industry," with Henna Trewn, *Public Utilities Fortnightly*, July 2017. https://www.fortnightly.com/fortnightly/2017/07/rethinking-customer-research
- "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Sanem Sergici, *Energy Regulation Quarterly*, 5:2, June 2017. http://www.energyregulationquarterly.ca/articles/do-manufacturing-firms-relocate-in-response-to-rising-electric-rates#sthash.uLnrPMwh.dpbs
- "Dynamic Pricing Works in a Hot, Humid Climate," with Neil Lessem and Sanem Sergici, *Public Utilities Fortnightly*, May 2017. https://www.fortnightly.com/fortnightly/2017/05/dynamic-pricing-works-hot-humid-climate
- "The impact of advanced metering infrastructure on energy conservation: A case study of two utilities," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:3, April 2017, pp. 56-63. http://www.sciencedirect.com/science/article/pii/S1040619017300726
- "The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, March 2017, pp. 60-65. http://www.sciencedirect.com/science/article/pii/S1040619016302536
- "Overcoming the Over-Forecasting Bias of Pure Econometric Models: A utility case study," with Josephine Duh and Ingrid Rohmund, *Electricity Policy*, February 2017.
- "The Impact of Time-of-Use Rates in Ontario," with Neil Lessem, Sanem Sergici, and Dean Mountain, *Public Utilities Fortnightly*, February 2017. https://www.fortnightly.com/fortnightly/2017/02/impact-time-use-rates-ontario

- "Competing Perspectives on Demand Charges," with Ryan Hledik, *Public Utilities Fortnightly*, September 2016. https://www.fortnightly.com/fortnightly/2016/09/competing-perspectives-demand-charges
- "An Economist's Dilemma: To PV or Not to PV, That Is the Question," *Electricity Policy*, March 2016. http://files.brattle.com/files/5834_2016_to_pv_or_not_to_pv__faruqui14march2016.pdf
- "Response to King-Datta Re: Time-Varying Rates," *Public Utilities Fortnightly*, March 2016. https://www.fortnightly.com/fortnightly/2016/03/response-king-datta-re-time-varying-rates
- "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, *Energy Economics*, 52, December 2015, pp. 39-48.
- "Efficient Tariff Structures for Distribution Network Services," with Toby Brown and Lea Grausz, **Economic Analysis and Policy**, 48, December 2015, pp. 139-149.
- "The Emergence of Organic Conservation," with Ryan Hledik and Wade Davis, *The Electricity Journal*, Volume 28, Issue 5, June 2015, pp. 48-58. http://www.sciencedirect.com/science/article/pii/S1040619015001074
- "The Paradox of Inclining Block Rates," with Ryan Hledik and Wade Davis, *Public Utilities Fortnightly*, April 2015. http://www.fortnightly.com/fortnightly/2015/04/paradox-inclining-block-rates
- "Smart by Default," with Ryan Hledik and Neil Lessem, *Public Utilities Fortnightly*, August 2014. http://www.fortnightly.com/fortnightly/2014/08/smart-default?page=0%2C0&authkey=e5b59c3e26805e2c6b9e469cb9c1855a9b0f18c67bbe7d8d4ca08a8abd39c54d
- "Quantile Regression for Peak Demand Forecasting," with Charlie Gibbons, SSRN, July 31, 2014. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2485657
- "Study Ontario for TOU Lessons," *Intelligent Utility*, April 1, 2014. http://www.intelligentutility.com/article/14/04/study-ontario-tou-lessons?quicktabs_11=1&quicktabs_6=2
- "Impact Measurement of Tariff Changes When Experimentation is Not an Option – a Case Study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, SSRN, March 2014. http://ssrn.com/abstract=2411832

- Dynamic Pricing in a Moderate Climate: The Evidence from Connecticut," with Sanem Sergici and Lamine Akaba, *Energy Journal*, 35:1, pp. 137-160, January 2014.
- "Charting the DSM Sales Slump," with Eric Schultz, *Spark*, September 2013. http://spark.fortnightly.com/fortnightly/charting-dsm-sales-slump
- "Arcturus: International Evidence on Dynamic Pricing," with Sanem Sergici, *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65. http://www.sciencedirect.com/science/article/pii/S1040619013001656
- "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," with Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, August 2013, pp. 571–584.
- "Benchmarking your Rate Case," with Ryan Hledik, *Public Utility Fortnightly*, July 2013. http://www.fortnightly.com/fortnightly/2013/07/benchmarking-your-rate-case
- "Surviving Sub-One-Percent Growth," *Electricity Policy*, June 2013. http://files.brattle.com/files/6849_surviving_sub-one percent_growth_faruqui_electricity_policy_june_2013.pdf
- "Demand Growth and the New Normal," with Eric Shultz, *Public Utility Fortnightly*, December 2012. http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal?page=0%2C1&authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98
- "Energy Efficiency and Demand Response in 2020 – A Survey of Expert Opinion," with Doug Mitarotonda, March 2012. Available at SSRN: http://ssrn.com/abstract=2029150
- "Dynamic Pricing for Residential and Small C&I Customers," presented at the Ohio Public Utilities Commission Technical Workshop, March 28, 2012. https://emp.lbl.gov/sites/default/files/oh-techsupport-faruqui.pdf
- "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," with Jennifer Palmer, *Energy Delta Institute*, Vol.4, No. 1, April 2012. https://issuu.com/edi_quarterly/docs/edi2030_quarterly_1_april
- "Green Ovations: Innovations in Green Technologies," with Pritesh Gandhi, *Electric Energy T&D Magazine*, January-February 2012. https://electricenergyonline.com/energy/magazine/618/article/Green-Ovations-Innovations-in-Green-Technologies.htm

- "Dynamic Pricing of Electricity and its Discontents" with Jennifer Palmer, *Regulation*, Volume 34, Number 3, Fall 2011, pp. 16-22. http://files.brattle.com/files/6373_dynamic_pricing_of_electricity_and_its_discontents_faruqui_aug_3_2011.pdf
- "Smart Pricing, Smart Charging," with Ryan Hledik, Armando Levy, and Alan Madian, *Public Utility Fortnightly*, Volume 149, Number 10, October 2011.
- "The Energy Efficiency Imperative" with Ryan Hledik, *Middle East Economic Survey*, Vol LIV: No. 38, September 19, 2011.
- "Are LDCs and customers ready for dynamic prices?" with Jürgen Weiss, *Fortnightly's Spark*, August 25, 2011.
- "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," with Sanem Sergici, *Journal of Regulatory Economics*, 40:1, August 2011, pp. 82-109.
- "Better Data, New Conclusions," with Lisa Wood, *Public Utilities Fortnightly*, March 2011, pp. 47-48.
- "Residential Dynamic Pricing and 'Energy Stamps,'" *Regulation*, Volume 33, No. 4, Winter 2010-2011, pp. 4-5. http://www.cato.org/pubs/regulation/regv33n4/v33n4.html
- "Dynamic Pricing and Low-Income Customers: Correcting misconceptions about load-management programs," with Lisa Wood, *Public Utilities Fortnightly*, November 2010, pp. 60-64. https://www.fortnightly.com/fortnightly/2010/11/dynamic-pricing-and-low-income-customers
- "The Untold Story: A Survey of C&I Dynamic Pricing Pilot Studies" with Jennifer Palmer and Sanem Sergici, *Metering International*, ISSN: 1025-8248, Issue: 3, 2010, p.104.
- "Household response to dynamic pricing of electricity–a survey of 15 experiments," with Sanem Sergici, *Journal of Regulatory Economics* (2010), 38:193-225.
- "Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," with Dan Harris and Ryan Hledik, *Energy Policy*, Volume 38, Issue 10, October 2010, pp. 6222-6231. http://www.sciencedirect.com/science/article/pii/S0301421510004738
- "Fostering economic demand response in the Midwest ISO," with Attila Hajos, Ryan Hledik, and Sam Newell, Energy, Volume 35, Issue 4, *Special Demand Response Issue*, April 2010, pp. 1544-1552. http://www.sciencedirect.com/science/article/pii/S0360544209004009

- "The impact of informational feedback on energy consumption – A survey of the experimental evidence," with Sanem Sergici and Ahmed Sharif, *Energy,* Volume 35, Issue 4, Special Demand Response Issue, April 2010, pp. 1598-1608. http://www.sciencedirect.com/science/article/pii/S0360544209003387
- "Dynamic tariffs are vital for smart meter success," with Dan Harris, *Utility Week*, March 10, 2010.
- "Rethinking Prices," with Ryan Hledik and Sanem Sergici, *Public Utilities Fortnightly*, January 2010, pp. 31-39. https://www.fortnightly.com/fortnightly/2010/01/rethinking-prices
- "Piloting the Smart Grid," with Ryan Hledik and Sanem Sergici, The Electricity Journal, Volume 22, Issue 7, August/September 2009, pp. 55-69. http://www.sciencedirect.com/science/article/pii/S1040619009001663
- "Smart Grid Strategy: Quantifying Benefits," with Peter Fox-Penner and Ryan Hledik, *Public Utilities Fortnightly*, July 2009, pp. 32-37. https://www.fortnightly.com/fortnightly/2009/07/smart-grid-strategy-quantifying-benefits
- "The Power of Dynamic Pricing," with Ryan Hledik and John Tsoukalis, *The Electricity Journal*, April 2009, pp. 42-56. http://www.sciencedirect.com/science/article/pii/S1040619009000414
- "Transition to Dynamic Pricing," with Ryan Hledik, *Public Utilities Fortnightly*, March 2009, pp. 26-33. http://www.fortnightly.com/display_pdf.cfm?id=03012009_DynamicPricing.pdf
- "Ethanol 2.0," with Robert Earle, *Regulation*, Winter 2009. https://object.cato.org/sites/cato.org/files/serials/files/regulation/2008/11/v31n4-noted.pdf#page=1
- "Inclining Toward Efficiency," *Public Utilities Fortnightly*, August 2008, pp. 22-27. https://www.fortnightly.com/fortnightly/2008/08/inclining-toward-efficiency
- "California: Mandating Demand Response," with Jackalyne Pfannenstiel, *Public Utilities Fortnightly*, January 2008, pp. 48-53.
- "Avoiding Load Shedding by Smart Metering and Pricing," with Robert Earle, *Metering International*, Issue 1 2008, pp. 76-77.
- "The Power of 5 Percent," with Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, *The Electricity Journal*, October 2007, pp. 68-77. http://www.sciencedirect.com/science/article/pii/S1040619007000991

- "Pricing Programs: Time-of-Use and Real Time," *Encyclopedia of Energy Engineering and Technology*, September 2007, pp. 1175-1183.
- "Breaking Out of the Bubble: Using demand response to mitigate rate shocks," *Public Utilities Fortnightly*, March 2007, pp. 46-48 and pp. 50-51. https://www.fortnightly.com/fortnightly/2007/03/demand-response-breaking-out-bubble
- "From Smart Metering to Smart Pricing," *Metering International*, Issue 1, 2007.
- "Demand Response and the Role of Regional Transmission Operators," with Robert Earle, 2006 Demand Response Application Service, *Electric Power Research Institute*, 2006.
- "2050: A Pricing Odyssey," *The Electricity Journal*, October 2006. https://www.researchgate.net/publication/222677841_2050_A_Pricing_Odyssey
- " Toward a New Paradigm for Valuing Demand Response," *The Electricity Journal*, Volume 19, Issue 4, May 2006, pp. 21-31.
- "Pushing the Envelope on Rate Design," with Stephen S. George, *The Electricity Journal*, Volume 19, Issue 2, March 2006, pp. 33-42. https://www.sciencedirect.com/science/article/abs/pii/S1040619006000054
- "Rate-Case Mania: Lessons for a New Generation," with Robert Earle, *Fortnightly Magazine*, February 2006.
- "Reforming electricity pricing in the Middle East," with Robert Earle and Anees Azzouni, *Middle East Economic Survey (MEES)*, December 5, 2005.
- "Controlling the thirst for demand," with Robert Earle and Anees Azzouni, *Middle East Economic Digest (MEED)*, December 2, 2005.
- "California pricing experiment yields new insights on customer behavior," with Stephen S. George, *Electric Light & Power*, May/June 2005. http://www.elp.com/index/display/article-display/229131/articles/electric-light-power/volume-83/issue-3/departments/news/california-pricing-experiment-yields-new-insights-on-customer-behavior.html
- "Quantifying Customer Response to Dynamic Pricing," with Stephen S. George, *Electricity Journal*, May 2005.
- "Dynamic pricing for the mass market: California experiment," with Stephen S. George, *Public Utilities Fortnightly*, July 1, 2003, pp. 33-35.
- "Toward post-modern pricing," Guest Editorial, *The Electricity Journal*, July 2003.

- "Demise of PSE's TOU program imparts lessons," with Stephen S. George. *Electric Light & Power*, January 2003, pp.1 and15.
- "2003 Manifesto on the California Electricity Crisis," with William D. Bandt, Tom Campbell, Carl Danner, Harold Demsetz, Paul R. Kleindorfer, Robert Z. Lawrence, David Levine, Phil McLeod, Robert Michaels, Shmuel S. Oren, Jim Ratliff, John G. Riley, Richard Rumelt, Vernon L. Smith, Pablo Spiller, James Sweeney, David Teece, Philip Verleger, Mitch Wilk, and Oliver Williamson. May 2003. Posted on the AEI-Brookings Joint Center web site, at http://www.aei-brookings.org/publications/abstract.php?pid=341
- "Reforming pricing in retail markets," with Stephen S. George. *Electric Perspectives*, September/October 2002, pp. 20-21.
- "Pricing reform in developing countries," *Power Economics*, September 2002, pp. 13-15.
- "The barriers to real-time pricing: separating fact from fiction," with Melanie Mauldin, *Public Utilities Fortnightly*, July 15, 2002, pp. 30-40.
- "The value of dynamic pricing," with Stephen S. George, *The Electricity Journal*, Volume 15, Issue 6, July 2002, pp. 45-55.
- "The long view of demand-side management programs," with Gregory A. Wikler and Ingrid Bran, in *Markets, Pricing and Deregulation of Utilities*, Michael A. Crew and Joseph C. Schuh, editors, Kluwer Academic Publishers, 2002, pp. 53-68.
- "Time to get serious about time-of-use rates," with Stephen S. George, *Electric Light & Power*, February 2002, Volume 80, Number 2, pp. 1-8.
- "Getting out of the dark: Market based pricing can prevent future crises," with Hung-po Chao, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf, *Regulation*, Fall 2001, pp. 58-62.
- "Analyzing California's power crisis," with Hung-po Chao, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf, *The Energy Journal*, Vol. 22, No. 4, pp. 29-52.
- "Hedging Exposure to Volatile Retail Electricity Prices," with Bruce Chapman, Dan Hansen and Chris Holmes, *The Electricity Journal*, June 2001, pp. 33-38.
- "California Syndrome," with Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *Power Economics*, May 2001, Volume 5, Issue 5, pp. 24-27.
- "The choice not to buy: energy savings and policy alternatives for demand response," with Steve Braithwait, *Public Utilities Fortnightly*, March 15, 2001.
- "Tomorrow's Electric Distribution Companies," with K. P. Seiden, *Business Economics*, Vol. XXXVI, No. 1, January 2001, pp. 54-62.

- "Bundling Value-Added and Commodity Services in Retail Electricity Markets," with Kelly Eakin, *Electricity Journal*, December 2000.
- "Summer in San Diego," with Kelly Eakin, *Public Utilities Fortnightly*, September 15, 2000.
- "Fighting Price Wars," *Harvard Business Review*, May-June 2000.
- "When Will I See Profits?" *Public Utilities Fortnightly*, June 1, 2000.
- "Mitigating Price Volatility by Connecting Retail and Wholesale Markets," with Doug Caves and Kelly Eakin, *Electricity Journal*, April 2000.
- "The Brave New World of Customer Choice," with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets, Public Utilities Report*, 1999.
- "What's in Our Future?" with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets, Public Utilities Report*, 1999.
- "Creating Competitive Advantage by Strategic Listening," *Electricity Journal*, May 1997.
- "Competitor Analysis," *Competitive Utility*, November 1996.
- "Defining Customer Solutions through Electrotechnologies: A Case Study of Texas Utilities Electric," with Dallas Frandsen et al. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.
- "Opportunities for Energy Efficiency in the Texas Industrial Sector," *ACEEE 1995 Summer Proceedings*.
- "Study on Energy Efficiency in Industry," with Jay W. Zarnikau et al. *ACEEE:* Washington, D.C., 1995.
- "Promotion of Energy Efficiency through Environmental Compliance: Lessons Learned from a Southern California Case Study," with Peter F. Kyricopoulos and Ishtiaq Chisti. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.
- "ATLAS: A New Strategic Forecasting Tool," with John C. Parker et al. *Proceedings: Delivering Customer Value*, 7th National Demand-Side Management Conference. EPRI: Palo Alto, CA, June 1995.
- "Emerging Technologies for the Industrial Sector," with Peter F. Kyricopoulos et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.

- "Estimating the Revenue Enhancement Potential of Electrotechnologies: A Case Study of Texas Utilities Electric," with Clyde S. King et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.
- "Modeling Customer Technology Competition in the Industrial Sector," *Proceedings of the 1995 Energy Efficiency and the Global Environment Conference*, Newport Beach, CA, February 1995.
- "DSM opportunities for India: A case study," with Ellen Rubinstein, Greg Wikler, and Susan Shaffer, *Utilities Policy*, Vol. 4, No. 4, October 1994, pp. 285-301.
- "Clouds in the Future of DSM," with G.A. Wikler and J.H. Chamberlin. *Electricity Journal*, July 1994.
- "The Changing Role of Forecasting in Electric Utilities," with C. Melendy and J. Bloom. The Journal of Business Forecasting, pp. 3-7, Winter 1993–94. Also appears as "IRP and Your Future Role as Forecaster." *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI).* San Diego, CA, September 1993.
- "Stalking the Industrial Sector: A Comparison of Cutting Edge Industrial Programs," with P.F. Kyricopoulos*. Proceedings of the 4CEEE 1994 Summer Study on Energy Efficiency in Buildings. ACEEE*: Washington, D.C., August 1994.
- "Econometric and End-Use Models: Is it Either/or Both?" with K. Seiden and C. Melendy. *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI).* San Diego, CA, September 1993.
- "The Potential for Energy Efficiency in Electric End Use Technologies," with G. Wikler, C. W. Gellings and K. Seiden*, IEEE Transactions on Power Systems,* Volume 8, No. 3, Aug. 1993, pp. 1351-1357.
- "Savings from Efficient Electricity Use: A United States Case Study," with C.W. Gellings and S.S. Shaffer. *OPEC Review*, June 1993.
- "The Trade-Off Between All-Ratepayer Benefits and Rate Impacts: An Exploratory Study," *Proceedings of the 6th National DSM Conference.* With J.H. Chamberlin. Miami Beach, FL. March 1993.
- "The Potential for Energy Efficiency in Electric End-Use Technologies," with G.A. Wikler, K.P. Seiden, and C.W. Gellings. *IEEE Transactions on Power Systems*. Seattle, WA, July 1992.
- "Potential Energy Savings from Efficient Electric Technologies," with C.W. Gellings and K.P. Seiden. Energy Policy, pp. 217–230, April 1991.

- "Impact of Demand-Side Management on Future Customer Electricity Demand: An Update," with K.P. Seiden, R. Bejamin, and J.H. Chamberlin, September 1990.
- "Demand Forecasting Methodologies: An overview for electric utilities," with Thomas Kuczmowski and Peter Lilienthal, *Energy: The International Journal*, Volume 15, Issues 3-4, March-April 1990, pp. 285-296.
- "The role of demand-side management in Pakistan's electric planning," *Energy Policy*, August 1989, pp. 382-395.
- "Pakistan's Economic Development in a Global Perspective: A profile of the first four decades, 1947-87," with J. Robert Malko, *Asian Profile*, Volume 16, No. 6, December 1988.
- "Marketing Electricity: A Military Approach," *Science Direct*, Volume 20, Issue 4, August 1987, pp 67-77.
- "Preface On the Search for Accuracy in Electric Utility Forecasting," *Journal of Forecasting (1986-1998)*; Chichester, Volume 6, Issue 2, April – June 1987, p. 93.
- "Time-of-Day Pricing of Electricity: Industrial and Commercial Customers," with J. Robert Malko, Philip R. Swensen, *Utah State University*, 1987.
- "The Residential Demand for Electricity by Time-of-Use: A survey of twelve experiments with peak load pricing," with J. Robert Malko, *Energy: The International Journal*, Volume 8, Issue 10, October 1983, pp. 781-795.
- "Incorporating the Social Imperatives in Economic Structure: Pakistan in the years ahead," *The Journal of Economic Studies*, Volume 1, No. 1, Autumn 1974.

BOOKS

- *The Electricity Journal, Special Issue: Rate Design*, Editor, Volume 31, Issue 8, October 2018.
- *Electricity Pricing in Transition.* Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2002.
- *Pricing in Competitive Electricity Markets.* Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2000.
- *Customer Choice: Finding Value in Retail Electricity Markets.* Co-editor with J. Robert Malko. Public Utilities Inc. Vienna. Virginia: 1999.
- "Forecasting in a Competitive Environment: The Need for a New Paradigm*," Demand Forecasting for Electric Utilities*, Clark W. Gellings (ed.), 2nd edition, Fairmont Press, 1996.

- *The Changing Structure of American Industry and Energy Use Patterns*. Co-editor with John Broehl. Battelle Press, 1987.
- *Customer Response to Time of Use Rates: Topic Paper I,* with Dennis Aigner and Robert T. Howard, Electric Utility Rate Design Study, EPRI, 1981.

CHAPTERS IN BOOKS

- "Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry.* Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.
- "Arcturus: An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green Energy and Technology*. Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.
- "Is Zero Energy Growth in Our Future," *A Chapter in Energy Efficiency*, December 2013.
- "Will Energy Efficiency make a Difference," with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth*. Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.
- "The Ethics of Dynamic Pricing." *Smart Grid: Integrating Renewable, Distributed & Efficient Energy*. Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.
- "The Dynamics of New Construction Programs in the 90s: A Review of the North American Experience," with G.A. Wikler. *Proceedings of the 1992 Conference on New Construction Programs for Demand-Side Management*, May 1992.
- "Forecasting Commercial End-Use Consumption" (Chapter 7), "Industrial End-Use Forecasting" (Chapter 8), and "Review of Forecasting Software" (Appendix 2) in *Demand Forecasting in the Electric Utility Industry*. C.W. Gellings and P.E. Lilbum (eds.): The Fairmont Press, 1992.
- "Innovative Methods for Conducting End-Use Marketing and Load Research for Commercial Customers: Reconciling the Reconciled," with G.A. Wikler, T. Alereza, and S. Kidwell. *Proceedings of the Fifth National DSM Conference*. Boston, MA, September 1991.
- "Time-of-Use Rates and the Modification of Electric Utility Load Shapes," with J. Robert Malko, *Challenges for Public Utility Regulation in the 1980s*, edited by H.M. Trebing, Michigan State University Public Utilities Papers, 1981.

- "Implementing Time-Of-Day Pricing of Electricity: Some Current Challenges and Activities," with J. Robert Malko, *Issues in Public Utility Pricing and Regulation*, edited by M. A. Crew, Lexington Books, 1980.

TECHNICAL REPORTS

- *Modernizing Distribution Rate Design*, with Ryan Hledik and Lam Long, prepared for ATCO Ltd., March 13, 2020.
- *Curating the Future of Rate Design for Residential Customers*, with Wade Davis, Josephine Duh and Cody Warner, Electricity Policy: Electricity Daily, July 2016.
- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study*, with Nei, Sanem Sergici, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator, February 2016. http://www.ieso.ca/-/media/files/ieso/document-library/conservation-reports/final-analysis-of-ontarios-full-scale-roll-out-of-tou-rates.pdf
- *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast*, with Sanem Sergici and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.
- *Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs*, with Toby Brown, prepared for the Australian Energy Market Commission, August 2014.
- *Time-Varying and Dynamic Rate Design*, with Ryan Hledik and Jennifer Palmer, prepared for RAP, July 2012. https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf
- *The Costs and Benefits of Smart Meters for Residential Customers*, with Adam Cooper, Doug Mitarotonda, Judith Schwartz, and Lisa Wood, prepared for Institute for Electric Efficiency, July 2011. http://www.edisonfoundation.net/iee/Documents/IEE_BenefitsofSmartMeters_Final.pdf
- *Measurement and Verification Principles for Behavior-Based Efficiency Programs*, with Sanem Sergici, prepared for Opower, May 2011. http://files.brattle.com/files/8217_measurement_and_verification_principles_for_behavior-based_efficiency_programs_sergici_faruqui_may_2011.pdf
- *Assessing Ontario's Regulated Price Plan*, with Phil Hanser, Ryan Hledik and Jenny Palmer. Ontario Energy Board, December 8, 2010.
- *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, with R. Lee, S. Bossart, R. Hledik, C. Lamontagne, B. Renz, F. Small,

D. Violette, and D. Walls. Pre-publication draft, prepared for the U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability, the National Energy Technology Laboratory, and the Electric Power Research Institute. Oak Ridge, TN: Oak Ridge National Laboratory, November 28, 2009.

- *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets*, with Sanem Sergici and Lisa Wood. Institute for Electric Efficiency, June 2009.
- *Demand-Side Bidding in Wholesale Electricity Markets*. With Robert Earle. Australian Energy Market Commission, 2008. https://www.aemc.gov.au/sites/default/files/content/a2f43d16-f48f-4983-8776-9bc1dd71de65/Report-on-Demand-Side-Bidding-in-Wholesale-Electricity-Markets-by-The-Brattle-Group.pdf
- *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)*. With Ingrid Rohmund, Greg Wikler, Omar Siddiqui, and Rick Tempchin. American Council for an Energy-Efficient Economy, 2008.
- *Quantifying the Benefits of Dynamic Pricing in the Mass Market*. With Lisa Wood. Edison Electric Institute, January 2008.
- California Energy Commission. *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF.
- *Applications of Dynamic Pricing in Developing and Emerging Economies*. Prepared for The World Bank, Washington, DC. May 2005.
- *Preventing Electrical Shocks: What Ontario—And Other Provinces—Should Learn About Smart Metering*. With Stephen S. George. C. D. Howe Institute Commentary, No. 210, April 2005.
- *Primer on Demand-Side Management*. Prepared for The World Bank, Washington, DC. March 21, 2005.
- *Electricity Pricing: Lessons from the Front.* With Dan Violette. White Paper based on the May 2003 AESP/EPRI Pricing Conference, Chicago, Illinois, EPRI Technical Update 1002223, December 2003.
- *Electric Technologies for Gas Compression*. Electric Power Research Institute, 1997.
- *Electrotechnologies for Multifamily Housing.* With Omar Siddiqui. EPRI TR-106442, Volumes 1 and 2. Electric Power Research Institute, September 1996.
- *Opportunities for Energy Efficiency in the Texas Industrial Sector.* Texas Sustainable Energy Development Council. With J. W. Zarnikau et al. June 1995.

- *Principles and Practice of Demand-Side Management*. With John H. Chamberlin. EPRI TR-102556. Palo Alto: Electric Power Research Institute, August 1993.
- *EPRI Urban Initiative: 1992 Workshop Proceedings (Part I).* The EPRI Community Initiative. With G.A. Wikler and R.H. Manson. TR-102394. Palo Alto: Electric Power Research Institute, May 1993.
- *Practical Applications of Forecasting Under Uncertainty.* With K.P. Seiden and C.A. Sabo.TR-102394. Palo Alto: Electric Power Research Institute, December 1992.
- *Improving the Marketing Infrastructure of Efficient Technologies: A Case Study Approach.* With S.S. Shaffer. EPRI TR- I 0 1 454. Palo Alto: Electric Power Research Institute, December 1992.
- *Customer Response to Rate Options.* With J. H. Chamberlin, S.S. Shaffer, K.P. Seiden, and S.A. Blanc. CU-7131. Palo Alto: Electric Power Research Institute (EPRI), January 1991.

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Utilities Need to Modernize their Tariffs to Enhance the Customer Experience: A National Perspective," presented to the 21st Century Energy Policy Task Force, Indiana, October 1, 2020.
- "Are Consumers Upending the Utility Business Model?" presented at the Florence School of Regulation, September 9, 2020.
- "Designing Tariffs for Tomorrow's Customer: The Innovation Imperative," presented to the Electricity Authority, September 2, 2020.
- "Designing Pilots and Proceeding with Full Scale Deployment," presented at the Washington Utilities and Transportation Commission, June 8, 2020.
- "The Five "Immortal Objections" to Time-of-Use Rates," presented at the PLMA Load Management Dialogue, May 28, 2020.
- " Stakeholder recommendations on rate design reform: Matter 357," with Cecile Bourbonnais, presented at the New Brunswick Energy and Utilities Board, May 12, 2020.
- "Moving Ahead with Time-Varying Rates (TVR): US and Global Perspectives," presented at the MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting, April 16, 2020.
- "Moving Ahead with Time-Varying Rates (TVR): US and Global Perspective," presented to the NARUC Staff Subcommittee on Rate Design, April 6, 2020.

- "Demand on Demand," presented at the AESP Annual Conference, February 20, 2020.
- "Empirical Assessment of the Demand for Residential Solar Distributed Generation and the Impact of Electricity Rate Design Reform," with Agustin J. Ros and Cecile Bourbonnais, presented at the Rutgers University Center for Research in Regulated Industries, January 17, 2020.
- "Assessment of APS's Bill Comparison Web Tool: Methodology and Findings," with Ryan Hledik and Cecile Bourbonnais, December 10, 2019.
- "A Survey of Residential Time-of-Use (TOU) Rates," with Ryan Hledik and Sanem Sergici, November 12, 2019.
- "Advancing the Practice of Rate Design," presented at the 40th PLMA Conference, November 6, 2019.
- "The Total Value Test (TVT) for Assessing Electrification Programs," with Ryan Hledik and Omar Siddiqui, presented at the California Efficiency + Demand Management Council (CEDMC), October 24, 2019.
- "A Conversation about Customer Centricity," presented at Virtual Speaker Forum, October 21, 2019.
- "Encouraging Rooftop Solar without Creating Cross-Subsidies," presented to SMUD, April 30, 2019.
- "Post-Modern Rate Design: The 'Secret Sauce' in Customer Engagement," presented at the Entergy Regulatory Conference, April 9, 2019.
- "Valuing and Compensating Distributed Energy Resources in ERCOT," with Ira Shavel and Yingxia Yang, prepared for the Texas Clean Energy Coalition, March 28, 2019.
- "2040: A Pricing Odyssey," presented at the EEI Spring Rates and Regulatory Affairs Committee Meeting, March 25, 2019.
- "Reinventing Demand Response for the Age of Renewable Energy," with Ryan Hledik, December 14, 2018.
- "Enabling Grid Modernization through Alternative Rates and Alternative Regulation," with Sanem Sergici and William P. Zarakas, presented at the Energy Policy Roundtable in the PJM Footprint, November 29, 2018.
- "Modernizing Distribution Tariffs for Households," presented to the Energy Consumers Association in Sydney, Australia, November 9, 2018.

- "The State of Electric Vehicle Home Charging Rates," with Ryan Hledik and John Higham, presented to Colorado PUC, October 2018.
- "Rate Design to Enable Flexible Loads," with Mariko Geronimo Aydin, presented at APPA Business & Financial Conference 2018, September 18, 2018.
- "Customer-driven Rate Design is the Wave of the Future," presented at the Colorado Rural Electric Association Managers Association Meeting, September 10, 2018.
- "Understanding the Costs and Benefits of Electrification: Electrification Cost-Benefit Case Studies," presented at the Electric Power Research Institute (EPRI) Electrification 2018 International Conference & Exposition, August 23, 2018.
- "Do Load Shapes of PV Customers Differ From Other Customers?" with Walter Graf, Presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Tariffs of the Future for Gas Utilities," with Léa Grausz, Henna Trewn, and Cecile Bourbonnais, presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Collecting Allowed Revenues When Demand is Declining," with Henna Trewn and Léa Grausz, presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Incentivizing the Adoption of Gas-Fueled Emerging Technologies with Pricing Tools," with Léa Grausz, presented at the 27th World Gas Conference, June 25, 2018.
- "Estimating the Impact of Innovative Rate Designs," presented to Southern California Edison, June 7, 2018.
- "Rate Design 3.0 and The Efficient Pricing Frontier," presented at the EUCI 2018 Residential Demand Charges Conference, Nashville, TN, May 15, 2018.
- "Does Dynamic Pricing of Electricity Eliminate the Need for Demand Charges?" presented at the Harvard Electricity Policy Group's (HEPG) 89th Plenary Session, January 25, 2018.
- "Dynamic Pricing: What Can We Learn from Other Jurisdictions?" presented at the California Public Utilities Commission's (CPUC) Electric Rate Forum, December 12, 2017.
- "Demand Charges and Dynamic Pricing Are Complements, Not Substitutes," presented at the California Public Utilities Commission's (CPUC) Electric Rate Forum, December 11, 2017.

- "Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida," with Sanem Sergici and Neil Lessem, presented at the International Energy Policy & Programme Evaluation Conference, November 2, 2017.
- "A Hybrid Model for Forecasting Electricity Sales and Peak Demand: A Case Study of TNB in Malaysia," with Sanem Sergici and Neil Lessem, presented at the International Energy Policy & Programme Evaluation Conference, November 2, 2017.
- "Workshop on Pricing Reforms," with Neil Lessem, Presented to Energy Networks Association (ENA), October 17, 2017.
- "A Walk on the Frontier of Rate Design," with Cody Warner, presented to the Western Farmers Electric Cooperative's Residential Demand Workshop, October 5, 2017.
- "The Future of Tariff Reform: A Global Survey," with Léa Grausz and Hallie Cramer, presented to the Indiana Energy Association's (IEA) Annual Energy Conference, September 28, 2017.
- "Forecasting the Impact of DSM on Energy Sales," with Zhen Wang, presented to the Edison Electric Institute (EEI), September 14, 2017.
- "A Global Survey of Customer-centric Tariff Reforms," with Neil Lessem, presented to the Commerce Commission, Wellington, New Zealand, August 24, 2017.
- "The Public Benefits of Leasing Energy Efficient Equipment: A Utility Case Study," with Henna Trewn and Neil Lessem, presented at the Center for Research in Regulated Industries' (CRRI) 30th Annual Western Conference, June 30, 2017.
- "Estimating the Impact of DSM on Energy Sales Forecasts: A Survey of Utility Practices," with James Hall and Zhen Wang, presented at the Center for Research in Regulated Industries' (CRRI) 30th Annual Western Conference, June 29, 2017.
- "Moving Forward with Tariff Reform," presented during the EEI Webinar on Rate Design, April 6, 2017.
- "An Irreverent Take on Customer Research in Our Industry," presented at the EPRI Workshop: Understanding Customer Preferences for and Adoption of New Services and Technology, April 4, 2017.
- "The Tariffs of Tomorrow," presented at the University of California, Davis Energy Efficiency Center Seminar, January 11, 2017.

- “Residential Demand Charges, Distributional Effects and Energy Storage,” with contributions from Ryan Hledik, presented during the Edison Electric Institute (EEI) Grid Talk Webinar, November 17, 2016.
- “Curating the Future of Rate Design,” presented at the EUCI’s Residential Demand Charges Conference, October 20, 2016.
- “Understanding Residential Customer Response to Demand Charges: Present and Future,” with Sanem Sergici and Ryan Hledik, presented at EUCI’s Residential Demand Charges Conference, October 20, 2016.
- “Technology's Role, Rates and Customers, 1985-2016,” presented at the Wisconsin Public Utility Institute, August 16, 2016.
- “Dynamic Pricing & Demand Response,” with Sanem Sergici, presented at IPU's 58th Annual Regulatory Studies Program: The Fundamentals Course, August 11, 2016.
- “Retail Costing and Pricing for Electricity,” with Philip Q Hanser and Sanem Sergici, presented at IPU's 58th Annual Regulatory Studies Program: The Fundamentals Course, August 11, 2016.
- “Emerging Issues in Forecasting Energy Consumption,” with Josephine Duh and Zhen Wang, Presented at the CRRI Western Conference 2016, June 24, 2016.
- “A Three-Year Impact Evaluation of TOU Rates in Ontario, Canada,” with Neil Lessem, presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Western Conference, June 23, 2016.
- “Capturing Smart Meter Enabled Benefits in System Wide Rollouts: June 23, 2016,” presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Western Conference, June 23, 2016.
- “Residential Rates for the Utility of the Future,” presented at Grid Edge World Forum 2016, June 22, 2016.
- “Residential Rates for the Utility of the Future,” presented to the Alternative Rate Design Stakeholder Process for Xcel Energy, May 13, 2016.
- “Modeling Customer Response to Xcel Energy's RD-TOU Rate,” with Ryan Hledik, presented to Xcel Energy, April 21, 2016.
- “Residential Demand Charges: An Overview,” presented at the EEI Rate Committee Meeting, March 15, 2016.

- "A Conversation about Standby Rates," presented to Standby Rate Working Group Michigan Public Service Commission, January 20, 2016.
- "Competitive Electricity Pricing Strategies: A California Perspective," with J. Robert Malko, and Philip R. Swensen, presented at the Fourteenth Annual Rate Symposium, sponsored by the Missouri Public Service Commission, the University of Missouri-Columbia and Utah Sate University, held in Kansas City, Missouri, February 1988.
- "Response of Residential Electric Loads to Time-of-Use Rates: Evidence from Eleven Pricing Experiments," with J. Robert Malko, presented at Midwest Economics Association Annual Meeting, Louisville, Kentucky, April 1981.

SELECTED HONORS & AWARDS

2023	ESIG Excellence Award
2020	*Who's Who Legal*: Energy Experts
1990–2020	Association of Energy Services Professionals (AESP): Recognized as one of seven individuals who was a game changer in the profession during the past 30 years
1976–77	Regents' Fellowship, The University of California at Davis
1977–78	Dissertation Grant, Kellogg Foundation
1973	Overseas Doctoral Scholarship, Government of Pakistan
1973	Rashid Minhas Gold Medal in Economics, University of Karachi

*Forthcoming chapter**, Handbook on Electricity Regulation,** edited by Jean-Michel Glachant, Paul Joskow and Michael Pollitt.*

Time Varying Rates (TVRs) are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States

Ahmad Faruqui and Ziyi Tang[1]

"There's never been any lack of interest in the subject of electricity tariffs. Like all charges upon the consumer, they are an unfailing source of annoyance to those who pay, and an argument among those who levy them… There is general agreement that appropriate tariffs are essential to any rapid development of electricity supply and there is complete disagreement as to what constitutes an appropriate tariff."

D. J. Bolton[2]

Electric tariffs for residential customers[3] through the 1960's were almost entirely volumetric rate designs expressed in cents per kWh. Often, the energy charge dropped with usage, making it a declining block rate.

In those days, the provision of electricity followed a declining cost curve and rates reflected that phenomenon. In the early 1950's, Lewis Strauss, chair of the US Atomic Energy Commission, had famously said the day would come when electricity would be too cheap to meter.[4]

That day never came. Instead, rate shock arrived when OPEC imposed an oil embargo which followed the Yom Kippur War of 1973. It was further amplified when the Iranian Revolution occurred in 1979. In November 1978, the Public Utilities Regulatory Policies Act (PURPA) was passed.[5] It made energy conservation a priority. Load management of electric loads was expanded to include time-of-use (TOU) pricing. A few states in the Mid-Atlantic region decided to make these rates mandatory for very large customers. One state provided incentives for customers to install thermal energy storage equipment and to pair it with a TOU rate.[6] In addition, 16 pilots with TOU rates were launched by the Federal Energy Administration (FEA). They were dispersed throughout the US and included the territory of Puerto Rico.

These pilots received widespread attention. Their results were evaluated by the Research Triangle Institute in North Carolina. At the behest of the National Association of Regulatory Utility Commissioners (NARUC), the Electric Power Research Institute (EPRI) launched the Electric Utility Rate Design Study (EURDS) in 1976. Among other topics, it reviewed and summarized the results of the FEA pilots.[7] Later, EPRI combined the data from the five best pilots and published a meta-analysis.[8]

---

[1] The authors are Principal Emeritus and Electricity Modeling Specialist respectively with The Brattle Group. This chapter reflects their views and not those of Brattle. They have benefited from comments by Steve Barrager, John Chamberlin, Soren Christian, Chris King, Mark Kolesar, Stephen Littlechild, Bruce Mountain, Bruce Nordman, Mike Oldak, Hethie Parmesano, Branko Terzic and Bill Uhr.

[2] Bolton (1938).

[3] Unless otherwise qualified, in the rest of this chapter the term "customer" refers to residential customers.

[4] https://www.nrc.gov/reading-rm/basic-ref/students/history-101/too-cheap-to-meter.html.

[5] 16 USC Ch. 46: PUBLIC UTILITY REGULATORY POLICIES (house.gov)

[6] "How to level the load," *The Energy Daily*, December 5, 1985.

[7] For the early history of the EURDS, see Robert G. Uhler (1976). He was the first Executive Director and was succeeded by Rene Males.

[8] Douglas W. Caves, Laurits R. Christensen, and Joseph A. Herriges (1984).

Lack of interval metering posed a major barrier to TOU pricing. So did the consistent opposition of consumer advocates. They favored flat volumetric rates. As an in-between measure, inclining block rates were introduced.

In the 1980's, Demand-Side Management (DSM) was spread throughout the US.[9] DSM included utility energy efficiency programs and government codes and standards to promote energy efficiency and load management. Tariff reform took a back seat.[10]

To offset rising bills, retail choice became a priority in the 1990s. It succeeded with large commercial and industrial customers but made little headway with households.

TOU rates languished in the US until California's energy crisis of 2000-01. Soon thereafter, TVR including TOU rates and newly introduced dynamic pricing garnered interest. Dynamic pricing included critical-peak pricing (CPP) and real-time pricing (RTP). In this chapter, TOU rates and dynamic pricing rates are called time-varying rates (TVR).

A second generation of TOU pilots was carried out, initially in California[11], and later in Connecticut, Florida, Illinois Maryland and Michigan.[12] Simultaneously, smart meters began to be rolled out.

Today, 104 million smart meters are deployed at US households, representing 73 % of all residential meters. TVR are finally getting significant attention. In 2022, 9.4% of households were on TOU rates, more than double the percentage in 2018, which had not changed much since 2013. If the trend continues, some 25-35% of households may be on TOU rates by 2030.

This chapter is organized as follows:

Section 1: Evolution of TVR

Section 2: Lessons Learned from Four Decades of Deploying TVR

Section 3: Strategies for Rate Modernization

Section 4: What's Likely to Happen in the Future?

Section 5: Conclusions

Section 1: The Evolution of TVR

With rare exceptions, electric rates for households in the US did not feature time variation until the 1960's.[13] The preferred medium for managing peak loads was direct load control of water heaters and central air conditioners.

[9] Clark W. Gellings and John H. Chamberlin (1993).
[10] Academics and researchers continued to publish articles, such as Chao (1983).
[11] Ahmad Faruqui and Stephen S. George (2005).

[12] Ahmad Faruqui and Sanem Sergici (2011); Ahmad Faruqui, Sanem Sergici and Lamine Akaba (2013); Ahmad Faruqui, Sanem Sergici and Lamine Akaba (2014); and Ahmad Faruqui, Neil Lessem, and Sanem Sergici (2017).

[13] European countries were ahead of the US. See, e.g., Christophe Aubin, Denis Fougère, Emmanuel Husson, and Marc Ivaldi (1995) and F. M. Westfield (1980) and Valerie Lesgards et Edouard Rossat (2022).

Since the conclusion of the landmark Madison Gas and Electric Company case of August 1974, commissions, utilities, and intervenors began studying the desirability and feasibility of implementing TOU rates. In 1978, PURPA required commissions to consider and make a determination regarding the cost-effectiveness of TOU rates, which were accorded the status of a federal rate-making standard.

To address these issues, the FEA, a precursor to the Department of Energy, worked with several states and Puerto Rico to conduct pilots with TOU rates. The pilots represented the first of many waves that would follow and their designs were of uneven quality.[14] Even then, they showed that customers lowered their on-peak usage by curtailing it and/or shifting it to off-peak periods, thereby improving load factor and lowering costs.

Between the late seventies and the mid-eighties, EURDS went through four phases and published nearly a hundred reports. In its second phase, EURDS was directed by a Project Committee comprised of commissioners and utility vice presidents. At one point, it was headed by Professor Alfred Kahn, who chaired the New York Public Service Commission while on leave from Cornell University.[15]

In an interview with the EPRI Journal, he was quite vocal about the merits of TVR: "Never mind whether you want to go to incremental-cost pricing or stick with historical-average pricing. You should at least have time-of-consumption rates; rates that differ, reflecting the fact that, even historically, the costs of installing more capacity should not be put on people who consume off peak. They are not responsible for construction of that capacity. It is indisputable that the costs imposed on a system, if only the generating costs are different when you consume at peak on a hot summer day or you consume in the middle of the night-so that truly cost-based rates cannot avoid varying consumption, logically."[16]

J. Robert Malko, an economist from the Wisconsin Commission, managed EURDS.[17] Several advisory committees drawn from commissions and utilities guided the work of the EURDS. The utility staff were drawn from investor-owned utilities, municipal utilities and cooperatives.

The EURDS advisers agreed that TOU rates should be cost reflective, in accordance with the widely accepted Bonbright principles.[18] However, there was little agreement on whether they should be based on marginal or embedded costs. The majority supported basing rates on embedded costs, a practice that continues to this day.[19]

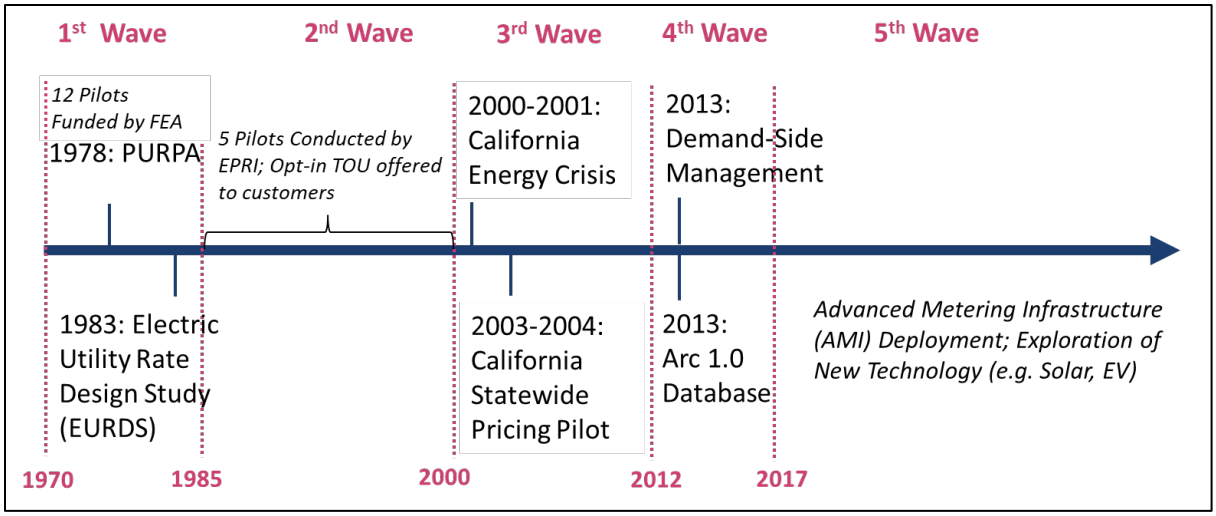
In the eighties, there was universal agreement that a big barrier to implementing TOU rates was the absence of interval metering. In the years that followed, a few utilities went ahead and installed interval meters. A few, especially in California, deployed TOU rates on a mandatory basis for their large commercial and industrial customers.

Figure 1 shows the evolution of TVR and how it interacted with other driving factors.

FIGURE 1 THE EVOLUTION OF TVR

[14] See Aigner (1985).
[15] "Alfred E. Kahn," *Wikipedia*, last modified February 5, 2023, https://en.wikipedia.org/wiki/Alfred_E._Kahn.
[16] "Alfred Kahn breaks tradition," *EPRI Journal*, December 1976, 42-45.
[17] Faruqui worked for him in the EURDS.
[18] James C. Bonbright (1961).

[19] Hethie S. Parmesano and Catherine S. Martin (1983).



First wave

Across the 16 pilots that were implemented, the short-run effects of TOU rates on customer electricity usage were encouraging but inconsistent. In most cases, customers materially reduced peak consumption in response to the TOU rates, with very little (if any) load-shifting to shoulder or off-peak periods. The reduction in peak consumption was statistically significant in many pilots.[20] The FEA found that higher peak-to-off-peak price ratios and shorter on-peak periods generally led to stronger customer response. However, these experiments did not test customer responses in the long run.

The industry mostly put the idea of TOU implementation on hold.

Second wave

The second wave began in the mid-1980s, when EPRI examined the results from five of the best designed FEA pilots and found consistent evidence of consumer behavior.[21] Unfortunately, not much came of this discovery because of the lack of smart metering infrastructure and because of the industry's focus on retail restructuring and the expansion of wholesale electricity markets. However, a few utilities did move ahead with mandatory TOU rates for large residential customers. Virtually all utilities moved ahead with opt-in TOU rates, but few customers took those rates.

In a related development, also in the 1980s, Bob Noyce, founder of Intel, and Mike Markkula, founder of Apple Computer invested in a startup company founded by Bill Uhr. These technology investors saw a major market opportunity in Uhr's microprocessor-based integrated thermal storage system that provided cooling, heating, and hot water for a 2500 square-foot home. Twelve pilots monitored by Virgina Power demonstrated that the systems could reduce the winter peak total house load by up to 90% and summer peak by up to 70%. Using TOU rates, the homeowners could save 25% to 35% on their annual electric bill. Notwithstanding the pilot success and serious interest by home builders, the company was unable to move into production due to the lack of utility support.

[20] Ahmad Faruqui and J. Robert Malko (1983).

[21] Douglas W. Caves, Laurits R. Christensen, and Joseph A. Herriges (1984).

Third wave

The 2000–01 California energy crisis gave impetus to the next wave of pilots with TVR. In addition to TOU rates, they featured dynamic pricing designs.[22] Unlike TOU, where the time periods and the prices for each period are known in advance, dynamic prices may or may not be known in advance and the time period over which the prices are invoked may or may not be fixed in advance. In the third wave, dynamic pricing pilots included studies of TOU pricing as well as other types of dynamic pricing. Some of these pilots featured enabling technologies such as in-home displays and smart thermostats.

In California, a statewide pricing pilot involving all three investor-owned utilities was conducted in 2003–04. It showed that customers reduced peak-period energy use in response to time-varying prices.[23] This pilot was a game changer. Since 2013, many more pilots have been conducted around the globe, bringing the total worldwide experience to almost 80 pilots featuring over 400 energy-only pricing treatments.[24] Figure 1 summarizes peak reduction effects from these pilots conducted through 2021, with each data point representing a single pricing treatment.

The figure shows that as customers' peak-to-off-peak price ratio increases, customers reduce their peak consumption more, although at a declining rate. The solid curve in Figure 2 show effects in response to prices only and without enabling technologies. Enabling technologies, such as smart thermostats, were shown to enhance customer responsiveness, as demonstrated by the dotted curve.[25] These results reinforce previous findings that customers do respond to price signals and that enabling technologies significantly enhance that responsiveness.

FIGURE 2 THE ARC OF PRICE RESPONSIVENESS BY TECHNOLOGY

[22] Ahmad Faruqui et al. (2001).
[23] "Impact Evaluation of the California Statewide Pricing Pilot," Charles River Associates, March 16, 2005, accessed at http://www.calmac.org/publications/2005-03-24_SPP_FINAL_REP.pdf.
[24] Ahmad Faruqui, Sanem Sergici and Cody Warner (2017); Ahmad Faruqui, Sanem Sergici and Ziyi Tang, "Do Customers Respond to TVR: A Preview of Arcturus 3.0" (2023).
[25] The difference between the curves is statistically significant and each of the curves by itself is also statistically significant.

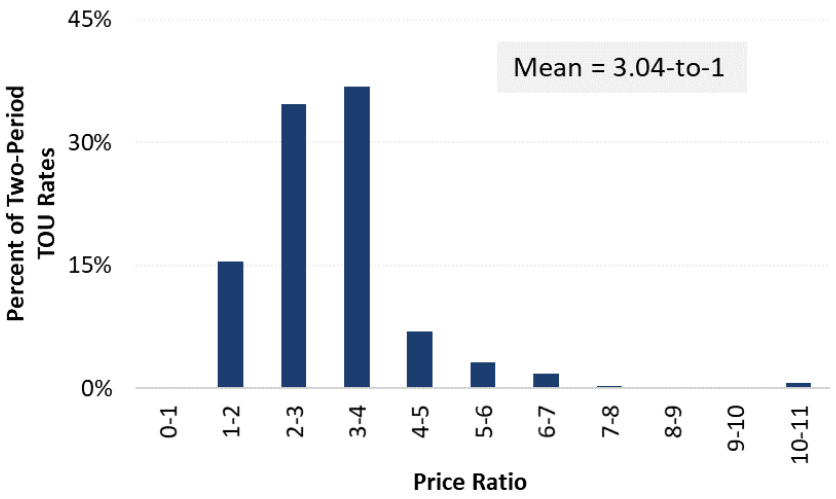
In the third wave of pilots, observers also discovered that low income customers can be price-responsive, although not to the same degree as the average residential customer. A 2012 study summarized the insights gained from these pilots.[26]

Overall, the third wave of pilots yielded rich information on customer responsiveness to time-varying pricing. Pilots in the third wave provided the impetus and scientific evidence for widespread investment in advanced metering infrastructure.

Fourth wave

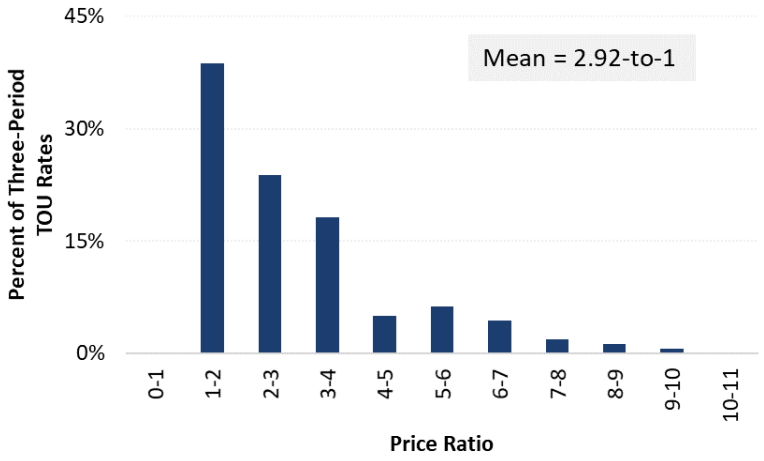
The fourth wave involved the large-scale rollout of TVR. Some featured two pricing periods and others featured three pricing periods. Today, the ratio of peak to off-peak prices in 85% of the two-period TOU rates is at least 2:1 while the mean price ratio is 3:1. TOU rates with three periods have a similar price ratio as those with two periods.[27]

FIGURE 3 PRICE RATIO IN TWO-PERIOD TIME-OF-USE RATES



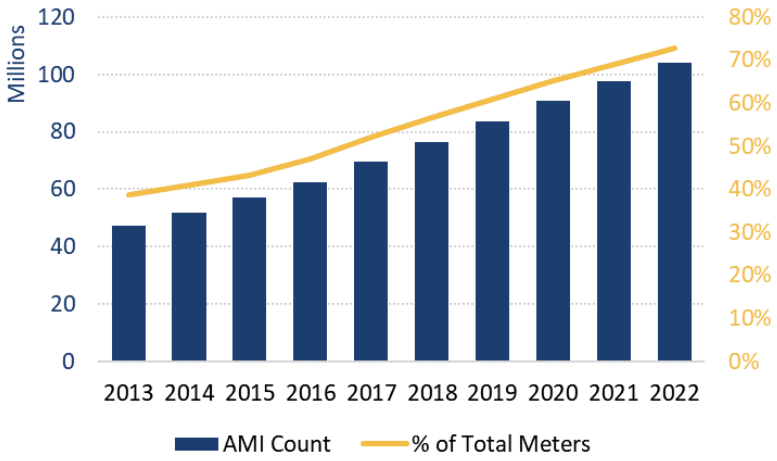
[26] Ahmad Faruqui, Ryan Hledik, and Jennifer Palmer (2012).
[27] US Department of Energy, Utility Rate Database, OpenEI, last modified February 2023, accessed at https://openei.org/wiki/Utility_Rate_Database.

FIGURE 4 PRICE RATIO IN THREE-PERIOD TIME-OF-USE RATES



In the fourth wave, the implementation of TVR did not keep pace with the installation of advanced metering infrastructure. According to EIA-861 Survey, 104.2 million households have advanced metering infrastructure, which is about 73% of total residential electric meters in 2022.[28]

FIGURE 5 SMART METER INSTALLATION (2013-2022)



But only 13.1 million households are enrolled on a TVR, which is about 9.4% of total number of residential customers. The barriers to large-scale implementation of TVR include:

- Insufficient evidence of benefits: Stakeholders are still not convinced benefits would be realized through full-scale deployment. Unless evidence of benefits is compelling, regulators, utilities, and customers will fear that a broader group of customers will be harmed by the new rates and that they will fail to promote economic efficiency or equity.
- Customer dissatisfaction and backlash: The move from flat rates to TVR will more efficiently and fairly allocate costs among individual customers but it will definitely raise bills for customers whose load factors

[28] "Annual Electric Power Industry Report", Form EIA-861, U.S. Energy Information Administration, Oct 5, 2023, accessed at https://www.eia.gov/electricity/data/eia861/.

are lower than the average load factor for the residential class. It may take time for those customers experiencing bill increases to understand how to manage their electricity consumption relative to the new rate structure. Additional investment in customer education and outreach will be needed to help customers fully understand the new rates, how to choose among their rate options, and how to adjust their usage patterns to lower their bills. It would be useful to give customers a choice of several rates, including flat rates, TOU rates with different price differentials across periods, and dynamic pricing rates.

- Effects on sensitive or disadvantaged customers: Special attention has to be paid to the needs of customers with medical disabilities, customers who are unemployed and low income customers in general.

Some questions remain about how customers will react with full-scale deployment, even though study after study has shown that such rates will yield real and quantifiable efficiency benefits to customers. Despite this evidence, there are persistent fears about a customer backlash or a failure to realize expected benefits. There are ways to overcome these fears, including:

- Customer bill effect studies: Utilities and regulators can conduct studies to understand how customer bills will be affected.
- Customer behavior studies: There are models available today for carrying out simulations to determine the likely customer response. These models draw from findings in prior pilot studies.
- Customer outreach and education: Utilities can engage in customer outreach programs to explain why tariffs are being changed and how the new tariffs will work. It will be important to ensure the new rates use clear and understandable language. Utilities can enlist neutral parties to endorse the change and they can use modern social media to spread the word.

Tapping into the newer generations of technology-savvy customers will be crucial. Utilities can develop new and more efficient ways to communicate with their customers, help to develop apps and smart energy tools, and otherwise explore methods to enhance the customer experience with technology. Here are some options for easing the transition:

- Transition rates: Utilities and regulators can design transition schemes that change the rates gradually over three to five years.
- Bill protection: Alternatively, bill protections can be provided to customers, ensuring that customer bills will not go up but they will be able to keep the savings, with those protections being phased out gradually over time.
- Add protections for sensitive customers: For the first five years, rates could be optional for sensitive or disadvantaged customers, such as low-income customers, small users, and disabled customers. Or these customers could be provided financial assistance for a limited period of time.
- Provide additional information and options to customers: There may be ways to provide additional options for customer participation. For example, consider a subscription concept in which customers “buy” their historical usage at the historical price, and buy or sell deviations from that usage at the new tariffs. This option would also help to transition into the fifth wave of tariff reform involving transactive energy.

Fifth Wave

We have now entered the fifth wave. Enabling residential customer responsiveness under TVR should be a priority. Once cost-reflective tariffs are in place, technological barriers will have to be overcome to achieve customer engagement. Better tools will have to be provided to customers to help them lower their bills.

New technology is already beginning to reveal to customers the extent to which electricity cost can vary depending on usage patterns over time. Public policies and initiatives are opening the door for households to have more control over the source of their electricity—beyond retail choice—through distributed generation. Smart appliances, thermostats, and apps are giving residential customers more tools to control and customize usage patterns. Customers will still have the right to access reliable power supply, but these changes will continue to give households more power to optimize their individual electricity use, their cost of electricity, and their environmental footprint.

We also expect continued improvements in data exchanges from and to smart houses to give residential customers opportunities to capture value directly from wholesale electricity markets. This means that customers will not only react to wholesale market and system conditions, but they will actively participate in wholesale markets through agents or technologies that allow customers to communicate and coordinate directly with market administrators and system operators. Not all customers will have the appetite for engaging in power supply decisions to this degree, but the newer generations of customers who are used to social media, fast-paced and complex communications, and a suite of apps to manage their lives will not find this foreign. Some customers will install solar panels, battery storage, and load flexible HVAC systems and appliances to lower their bills and take advantage of TVR.

In one vision of how this could evolve, customers would subscribe to a "baseline" load shape based on their typical usage patterns. They could buy or sell deviations from the baseline on the wholesale market through sophisticated energy management systems or agents. This was originally called "demand subscription," but the idea has morphed into "transactive energy".[29] This vision has gained some traction with millennials through Wi-Fi thermostats, digital appliances, and first-generation home energy management systems. Regardless of the specific method, we believe that in the future the gaps among customers, retail markets, and wholesale markets will be significantly reduced.

But this future cannot be realized if customers do not have even the basic information on how their usage patterns relate to the real cost structure of electricity. Customers cannot react to the high production and investment costs of electricity during peak demand periods if they are shielded from observing these costs at the point of consumption. Customers who are charged the traditional and mostly flat volumetric rate for electricity will be immobilized in the transactive energy future. They will not have the incentives or information necessary to lower their bills in an efficient manner, participate in valuable demand-side services in wholesale markets, or actively contribute to more efficient electricity production and investments in the future.

Household electricity historically has been mostly a uniform commodity for consumers, indistinguishable by source or time of use. For the most part, utilities could price electricity as if it were a uniform commodity without harming their bottom line. But in recent years a number of industry shocks and changes have made it clear that this pricing scheme is not always best for customers or utilities. The first four waves of tariff reform have gauged consumer response and enabled utilities to price electricity more efficiently as the diverse product it is. At the same time,

[29] Stephen Barrager and Edward Cazalet (2014).

customers are awakening to the diversity of electricity supply depending on location, time of day, and environmental attributes.

Driven by the need to reduce carbon emissions and to promote load flexibility, the California Public Utilities Commission (CPUC) is evaluating a rate design concept called CalFUSE in to enable widespread adoption of demand flexibility solutions.[30] The opt-in CalFUSE frameworks include a broad spectrum of six elements to: develop standardized, universal access to current electricity price, introduce dynamic prices based on real-time, wholesale energy cost, incorporate dynamic capacity charges based on real-time grid utilization, transition to bidirectional prices, offer subscription option, and introduce transactive features. The tariff separates the collection of energy and distribution costs and introduces the notion of scarcity pricing to allocate capacity charges to time periods.

Section 2: Lessons Learned from Deploying TVR

Several lessons can be gleaned from the past four decades which would help in designing better rates in the future.

1. Don't oversell the benefits of TVR

In the early 2000s, Puget Sound Energy in the Pacific Northwest rolled out what its CEO termed a "dynamic pricing" rate. But the new rate was simply a TOU rate with three pricing period. Notably, the price differential between the peak and off-peak periods was only 30%. Customers were informed they would save money on the rate. Some customers shifted nearly half their loads from peak to off-peak periods only to discover a year later that they had only saved 50 cents to a dollar per month. Customers felt cheated. Ten percent dropped out. Local and national media outlets reported on the story. The backlash was severe. The utility ended the program, giving TOU rates a bad rap.

Lesson: Don't oversell the savings from TVR.

2. Pilots are not Always Needed

After witnessing the California energy crisis, the Ontario Energy Board decided to move all customers in the province to TOU rates once smart meters had been deployed. No pilot preceded the TOU deployment. The TOU program succeeded because the Premier was a visionary.

Lesson: A pilot is not always necessary.

3. Embrace Gradualism

[30] California Public Utilities Commission (2022).

One of the most successful TOU programs in the U.S. was launched by SMUD in California. It conducted pilots with CPP and TOU rates. Results were positive and the utility decided to introduce them to its customers. The success of the roll-out campaign can be attributed to a smooth transition plan which spanned three years.

Another example is provided by the Australia Energy Market Commission. To accelerate the deployment of TOU rates, it suggested that they be made mandatory for the largest customers, opt-in for vulnerable customers and be the default for everyone else. However, advocates of the vulnerable customer group thought the design was "a trap" and vehemently opposed it. In the end, the plan did not win the government's approval and was scuttled.

Lesson: Coordinate the design and rollout of TVRs with all stakeholder.

4. Think Outside the (Service Territory) Box

Until 1990, RTP was an academic concept in the US[31] until Georgia Power introduced it to its large commercial and industrial customers. The utility hired a pricing manager from ESKOM in South Africa who had implemented a successful RTP program for large mining customers. Because mining uses electricity heavily and because mining operations can be disrupted, RTP was the perfect rate option for this sector. The pricing manager brought the practice with him to the U.S.

The RTP rate had a two-stage structure. In the first stage, customers paid what they had paid historically by holding their load profile constant. In the second stage, they paid for changes in the load profile on an hourly basis. The first stage bill included a fixed charge, a demand charge and a flat energy charge. In the second stage, the hourly prices were based on marginal energy costs. Customers were notified of the prices on an hour-ahead basis.

The utility recruited customers from inside and outside of the U.S. to relocate to the utility's service territory and participate in the RTP program. The program was designed for customers with maximum demands higher than 1 MW. Load dropped 17 percent on average whenever wholesale price exceeded $1/kWh. Initially offered to industrial customers, the program was later extended to commercial customers. Years later, a day-ahead version was made available to C&I customers with less than 1 MW demand.

Lesson learned: Persistence and perseverance pay off.

5. Key Decision Makers Need to be On Board

TVA, a federal agency, serves power to more than 150 publicly owned utilities in the southeastern US and also designs their rates. TVA wished to modernize its rate designs. However, smart metering was not available. To brainstorm solutions, the agency organized a workshop with its distribution utilities. After considering all the options, seasonal rates were proposed and everyone was on board with them. However, TVA's board rejected the idea. The board members were concerned that customers with central air conditioning systems would see higher bills.

Lesson: Anticipate adverse reaction from those who are going to see higher bills.

[31] It had been discussed elsewhere. See, e.g., Littlechild (2003).

6. Mind the Transition Costs

In Oklahoma, OGE's CEO asked his leadership team to explore demand-side solutions instead of building a 600-MW power plant. After doing comprehensive market research, the utility reached the conclusion that there was enough appetite for the utility to pilot a sophisticated variable-peak pricing (VPP) rate with four levels of critical-peak pricing. It also installed smart thermostats on customer premises. Instead of the utility controlling the thermostat, customers had their own control and could pre-set it to their comfort level in advance.

The pilot was successful and the utility offered VPP to all its customers on an opt-in basis. In five years, the participation rate reached nearly 15 percent. On average, the program reduced the peak demand of participating customers by 40 percent, lowering customer bills by 20 percent. The program's success was attributed to word-of-mouth marketing. The VPP prices were sent directly to the thermostat, where the customer had programmed the temperature settings by price.

Lesson: Customer centricity is vital to the success of innovative rates.

7. When There's a Will, there's a Way.

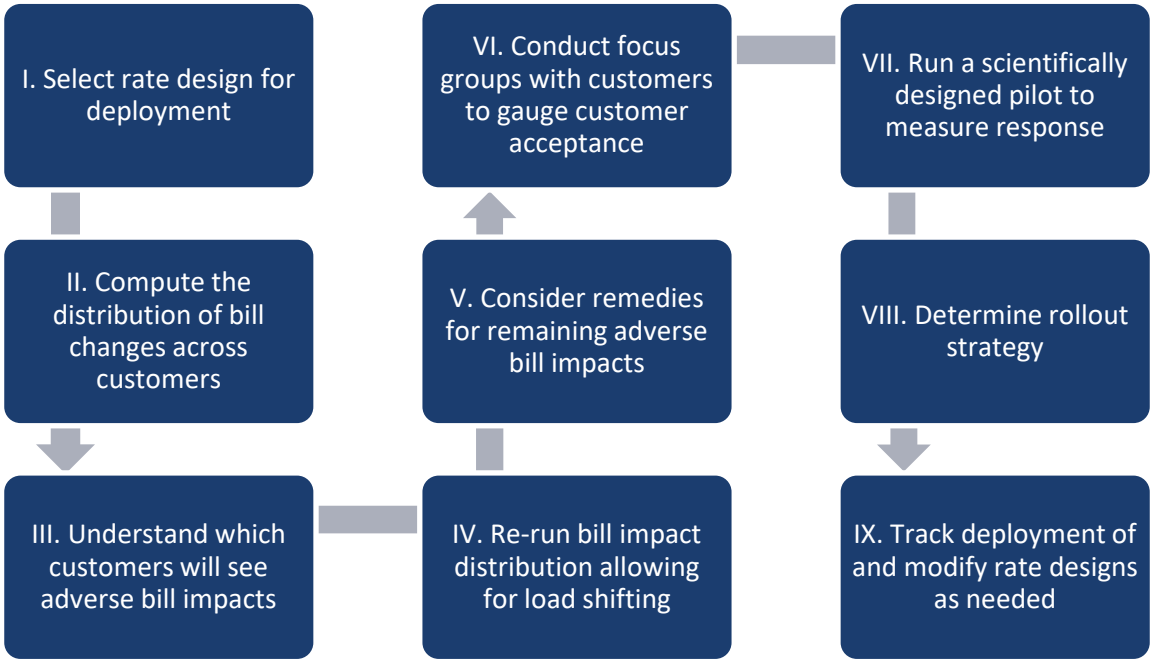
In the course of exploring rate design reforms in the late 2000s, BGE in Maryland became interested in applying the lessons learned from California's pricing pilots involving TOU rates and CPP rates which involved all three investor-owned utilities and ran for two years. The utility decided to launch a CPP pilot of its own and also pair it with a peak-time rebate (PTR) pilot. The pilot ran for four years. The results showed that the peak reduction from CPP and PTR were about the same. The utility decided to proceed with PTR since it believed that there were no losers under this design. PTR was offered to all customers as a default option. Analysis showed that some 88% of customers participated in it and peak demand during critical hours dropped by 15-20%.

Lesson: A PTR may be more palatable than a CPP rate.

Section 3: Strategies for Rate Modernization

Each utility follows its own pathway, depending on its particular circumstances. In general, most utilities follow this pathway.

FIGURE 6 A NINE-STEP PATHWAY FOR TRANSITIONING TO MODERN RATE DESIGN



I. Select Rate Design for Deployment

Select the specific rate design for deployment. In some case, more than one rate design may be picked for deployment. Utilities should evaluate each of these options and offer choices to customers along an efficient pricing frontier. Some of the choices being considered or offered by utilities to their customers are listed in the Table 1.[32] When these rate design options are offered to customers, they will be able to pick the one that represents the best combination of risk and reward.

FIGURE 7 THE EFFICIENT PRICING FRONTIER

[32] Ahmad Faruqui and Cecile Bourbonnais (2020).

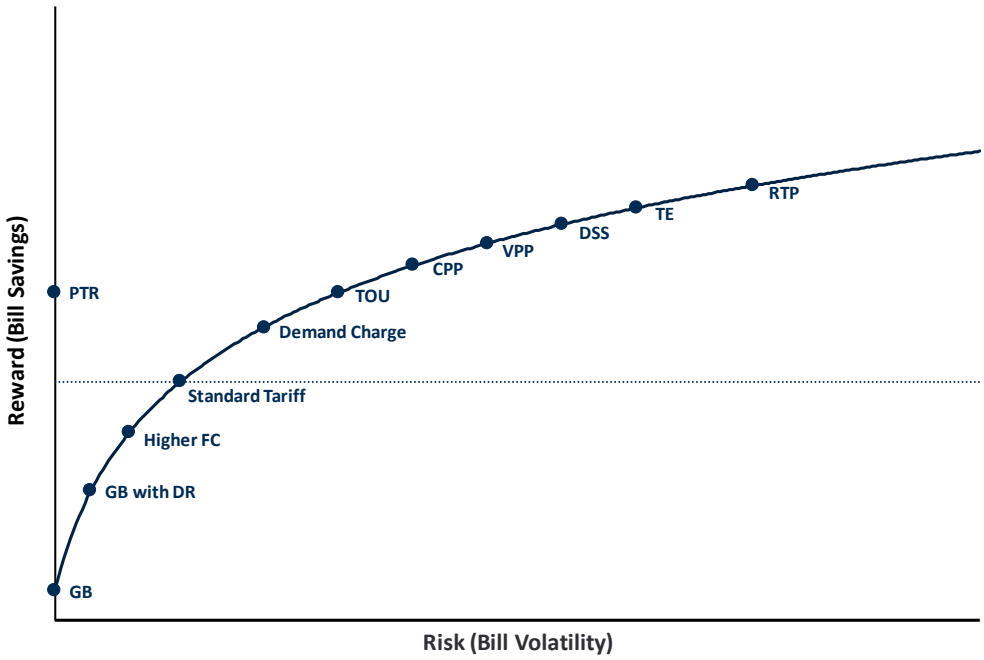
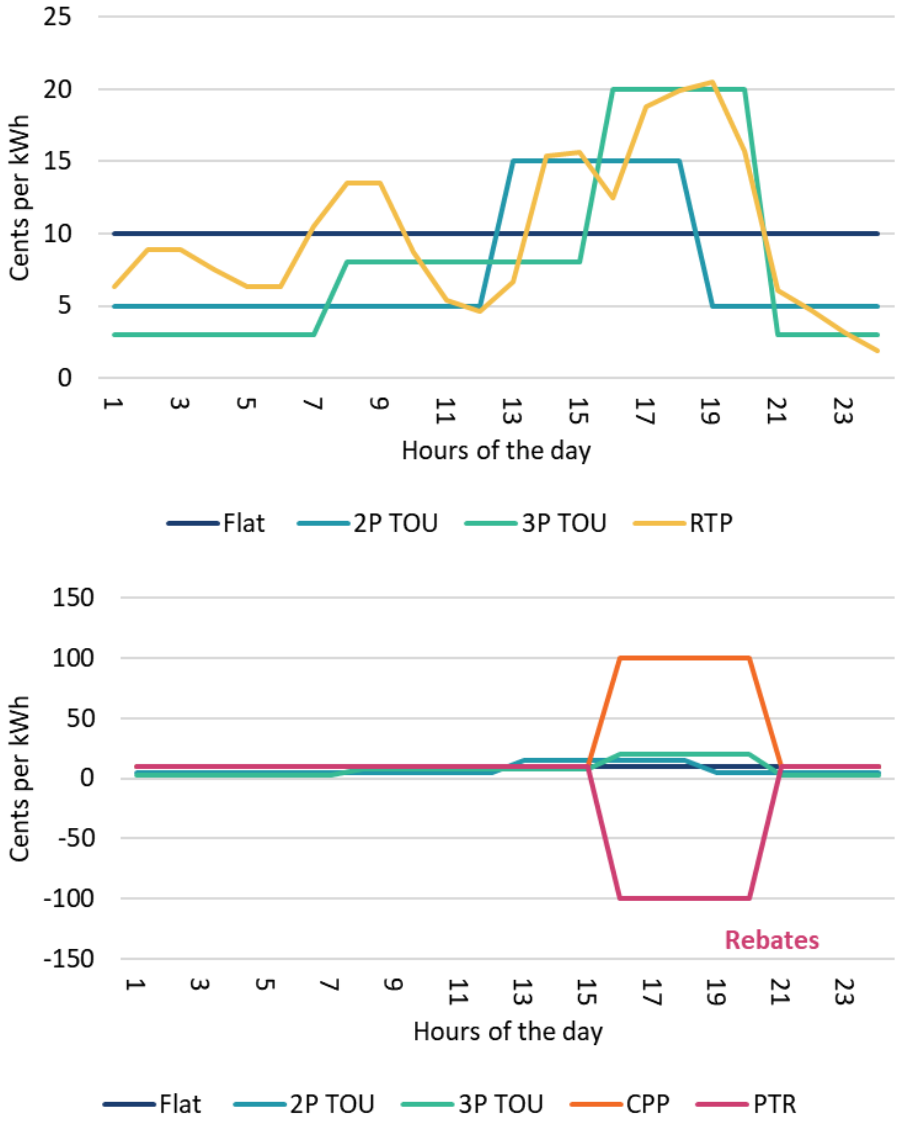


TABLE 1 RATE DESIGN OPTIONS

Rate Design	Definition
Guaranteed Bill (GB)	Customers pay the same bill every month, regardless of usage.
Flat Rate	A uniform $/kWh rate is applied to all usage.
Demand Charge	Customers are charged based on peak electricity consumption, typically over a span of 15, 30, or 60 minutes.
Time-of-Use (TOU)	The day is divided into time periods which define peak and off-peak hours. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period.
Critical Peak Pricing (CPP)	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed.
Inclining Block Rates (IBR)	Customers are charged a higher rate for each incremental block of consumption.
Peak Time Rebates (PTR)	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their "baseline").
Variable Peak Pricing (VPP)	During pre-defined peak periods, customers pay a rate that varies by utility to reflect the actual cost of electricity.
Demand Subscription Service (DSS)	Customers subscribe to a kW demand level based on the size of their connected load. If they exceed their subscribed level, they must reduce their demand to restore electrical service.
Transactive Energy (TE)	Customers subscribe to a "baseline" load shape based on their typical usage patterns, and then buy or sell deviations from their baseline.
Real-Time Pricing (RTP)	Customers pay prices that vary by the hour to reflect the actual cost of electricity.

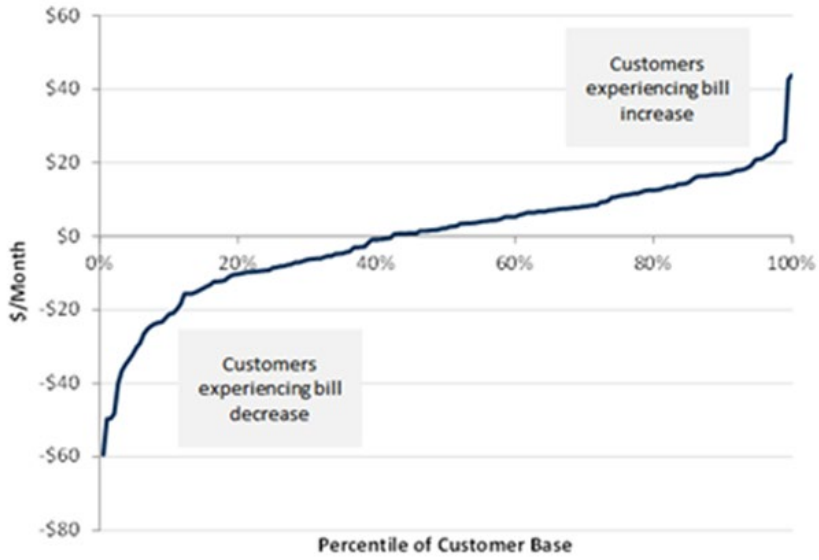
FIGURE 8 STYLIZED TIME-VARYING RATES



II. Estimate the distribution of bill changes across customers

For the chosen rate design(s), compute the impact of the rate design on a representative sample of customers. Plot the results in the form of a "propeller" chart, such as Figure 8, identifying those who are going to see higher bills and those who will see lower bills under the assumption that customers will not change their load shape.

FIGURE 9 DISTRIBUTION OF BILL IMPACTS



III. Understand which customers will see adverse bill impacts

Try to understand the sociodemographic and regional characteristics of those customers who are going to experience significantly higher bills. Identify policies that can be used to mitigate the adverse impacts. Examples include the offering the rebates to low-income customers and carrying out energy efficiency improvements in their facilities. If the rates would be offered to them on an opt-in basis, they could be given bill protection for the first year or two as they try them out. If the rates would be offered to them on an opt-out basis, such customers could be excluded from the default provisions altogether.

IV. Re-run bill impact distribution allowing for load shifting

Re-run the bill impact analysis by allowing for changes in load shapes that would occur as customers respond to the price signals. For example, lower off-peak rates would encourage them to raise off-peak usage and higher on-peak rates would encourage them to lower peak usage. Databases and models exist to simulate changes in customer load shapes. Changes in load shapes will mitigate the adverse bill impacts.

V. Consider remedies for remaining adverse bill impacts

If the adverse bill impacts are still significant for certain groups of customers, consider instituting one of these remedies shown in Table 2.

TABLE 2 REMEDIES FOR ADVERSE BILL IMPACT

Remedy	Implementation
Gradualism	Roll out the new rates gradually for each rate design element. For example, to introduce a TOU rate, if the peak price will be 25 ¢/kWh and the current tariff is 15 ¢/kWh, implement a peak price of 17 ¢/kWh in the first year and increase it annually by 2 ¢/kWh until it reaches 25 ¢/kWh.
Bill Protection	Provide customers with bill protection for a limited period so that they pay the lower of their old and new bill.
Optional Rates	Make the new rate design optional for vulnerable customers, mandatory for the largest customers, and the default for all other customers.

Financial Assistance	Provide customers with adverse bill impacts financial assistance for a limited period.
Enabling Technologies	Install enabling technologies such as smart thermostats on customer premises.
Two-staged Rollout	Structure the rate into two stages, where the first stage charges customers the current rate if their usage resembles a historical reference period, and the second stage exposes them to the new rate.

VI. Conduct focus groups with customers to gauge customer acceptance

These will help determine how best to communicate the rationale behind the selected rates and to see if they would be comfortable with the modern rate designs. Make appropriate modifications in language to make the modern rate designs understandable to customers.

VII. Run a scientifically-designed pilot to measure response

The pilot should be designed on scientific principles that would preserve the internal and external validity of the results, allowing them to be extrapolated to the population of customers. There are three ways of ensuring that pilots will yield results that are statistically valid and generalizable to the population at large. These include randomized control trials, randomized encouragement designs, and matching controls. Analysis of before-and-after data on the "treatment" customers who are on modern rates, and side-by-side data on treatment group and control group customers can then be carried out using econometric methods to yield a difference-in-differences estimate of the impact of the new rates on customer load shapes. Price elasticities can also be derived, allowing results to be predicted for a wide range of rates, not just those that are included in the pilot.

VIII. Determine rollout strategy

Decide on the rollout strategy. It could be opt-in, opt-out or mandatory. Examples of each are presented below.

- In Arizona, a variety of TOU rates are offered on an opt-in basis by two utilities, Arizona Public Service (APS) and the Salt River Project (SRP). About 61 percent of APS' customers and 35 percent of SRP's residential customers take service on a TOU rate. Analyses from a sample of customer numbers show that TOU rates with a shorter peak period yields an average reduction of 17% of on-peak kWh and TOU rates with a longer peak period have an average of 8% reduction.
- In Colorado, Fort Collins, a small utility, moved all its customers from volumetric rates to TOU rates in October 2018. The deployment was mandatory and it was preceded by a one-year pilot. The residential opt-out pilot showed a 2.5% reduction in energy consumption. Xcel Energy, a much bigger utility, began rolling out a default TOU rate in 2022 to all customers with smart meters. It was preceded by a pilot.
- In Michigan, Consumers Energy rolled out TOU rates as the default tariff to all its residential customers in 2021. The deployment was preceded by a pilot program that saw a general reduction in peak energy of between 3% and 4%. DTE Energy has recently rolled out TOU rates as the default tariff. Customers can opt-out to other rates but all of them are TOU rates. Both utilities offer choices but they are all TOU rates.
- In Illinois, Commonwealth Edison and Ameren offer RTP to their customers but only 2% have taken it.
- Georgia Power is rolling a few TOU rates to its residential customers, including a rate with a significantly lower off-peak rate designed specifically for EV owners.

- In Missouri, regulators have ordered Ameren and Evergy to roll out default TOU rates in October with peak to off-peak price ratio that range from 4:1 to 5:1. These are the highest such ratios in default TOU rates in the US.[33]

IX. Modify rate designs as needed

Finally, track the deployment of the modern rate design(s) and survey the customers for feedback. The utility can set up social media sites and monitor the conversation, and make necessary modifications in the rate design on a regular basis.

Section 4: What's Likely to Happen in the Future?

As utilities begin the transition to net zero, they will incentivize customers to install new technologies that promote electrification through rebates and low interest financing programs. Additional incentives will come from governments at the federal, state and local levels.

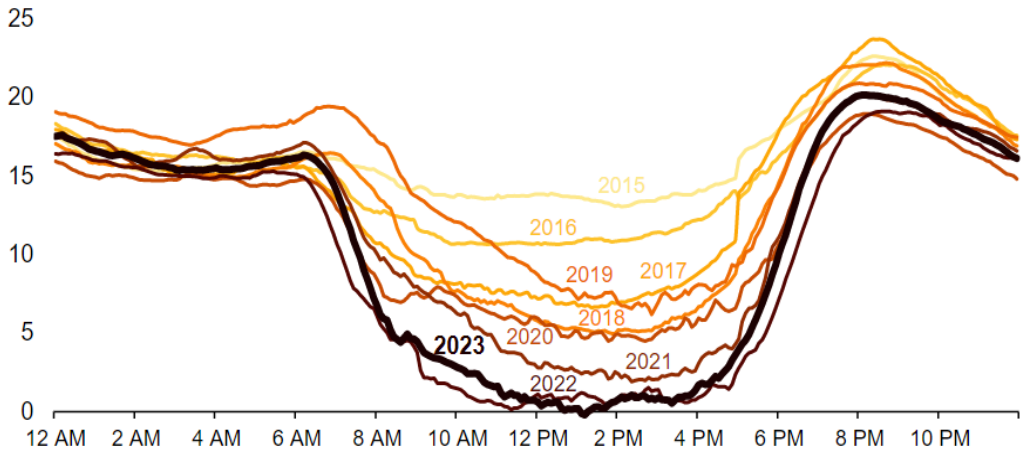
The most prominent technologies that are receiving incentives today are electric vehicles (EVs) and heat pumps. Also, faced with rising bills, and seeking to move toward an organic lifestyle, customers are moving forward by installing photovoltaic (PV) panels on their roofs. An increasing number of new PV installations are integrated with battery energy storage systems. They are receiving significant incentives from the federal government. Many of these customers also drive EVs.

As EVs and heat pumps are widely deployed, utilities will need to find a way for managing the growth in peak loads that will follow their deployment. As the share of large scale solar grows on the supply side, utilities will see that their net peak load will shift from the early afternoon hours to the late afternoon an early evening hours. This phenomenon, knowns as the duck curve (Figure 9), has already begun to happen in California.[34] The peak period used to run from noon to 6 pm about two decades ago. A decade ago, it shifted to the 2 pm to 7 pm window. Now it runs from 4 pm to 9 pm.

[33] Jeffrey Tomich, "Missouri overhauls electric rates, raising rewards – and risks – for customers", *EnergyWire*, July 12,2023, https://www.eenews.net/articles/missouri-overhauls-electric-rates-raising-rewards-and-risks-for-customers/.

[34] "As solar capacity grows, duck curves are getting deeper in California", U.S. Energy Information Administration, June 21, 2023, accessed at https://www.eia.gov/todayinenergy/detail.php?id=56880.

FIGURE 10 CALIFORNIA'S DUCK CURVE (CAISO LOWEST NET LOAD DAY EACH SPRING, 2015-2023, GW)



In Hawaii, the off-peak period now lies in the afternoon hours and the same is evident in Australia, where a "sponge tariff" is offered to encourage additional energy use in the afternoon hours.

In all of these cases, a TOU tariff will prove to be an indispensable resource to encourage off-peak charging. That's already the case in California where the off-peak period now begins at midnight, to encourage the nighttime charging of EVs.

More and more utilities are beginning to offer TOU rates with exceptionally low off-peak rates. These are often three-period rates where the off-peak period begins at midnight.

As for dynamic pricing, despite the substantial benefits that economists have pointed out,[35] the future remains uncertain:

- In Illinois, hourly real-time pricing is offered to the state's 4.7 million electric customers by its two investor-owned utilities. Under 2% of customers have taken it.
- In California, residential customers have been offered CPP for more than a decade. Only 2% of customers have taken it.[36]
- In Oklahoma, OG&E has had more success with a more advanced version of CPP known as variable-peak pricing (VPP). The price on critical days can rise to four different levels, depending on the severity of the demand-supply imbalance. Because of customer-friendly rate design and exceptionally good marketing, that pricing program has achieved an adoption rate of 14.7%. But it remains the exception to the rule.

New forms of pricing continue to evolve. The latest version is called Subscription Pricing. In that design, customers are offered a fixed bill based on their historical pattern of use. It's somewhat higher than their average monthly bill. It offers peace of mind to the customer and is akin to the type of pricing used by Internet providers and companies such as Netflix. A more advanced version of Subscription Pricing offers customers a chance to lower

[35] See, for example, Severin Borenstein (2005), Ahmad Faruqui (2010), William Hogan (2010), and Schittekatte et al. (2023, forthcoming).

[36] For experimental results from a small municipal utility in southern California, see Frank A. Wolak (2007).

their fixed bills by reducing their usage during critical hours when the demand-supply equation appears to be going out of balance. It's called Subscription+.[37]

Utilities are beginning to realize that the best way to enhance customer satisfaction is to give them choices of rates. Some want bill stability and are willing to pay a bit more for that. That's where subscription pricing comes in. Others want flat rates. Still others are willing to move some of their consumption out of the peak period to off-peak periods and are happy to go on a TVR. Most of the last group of customers are interested in a two or three period TOU rate but some are willing to try variants of dynamic pricing. They come with added risk but also can yield the lowest bills.

Section 5: Conclusions

The evolution of TVR in the US has been very slow over the past four decades for a number of reasons. Among them, lack of metering, consumer reluctance to try something new, and a fear that these rates will raise bills. Long peak pricing periods that spanned most of the day time hours were a major barrier to customer adoption.

Consumers don't put much stock in notions such as allocative efficiency that have the status of an axiomatic truth among economists. They don't care much about rates being cost based, consistent with the principles put forward by Bonbright.

Utilities have been reluctant to offer them on an optional basis, concerned that only those who would lower their bills would sign up for time-varying tariffs, eroding revenues. They have also been skeptical that TVR would induce load shifting from peak to off-peak periods, and lower costs for all customers by reducing the need for new capacity additions.

For decades, TVR were an exotic service offering, requiring the installation of a special interval meter. Today, smart meters are deployed in nearly 70% of American households. So are programmable thermostats, many come with WIFI capability, but even today few customers bother to program them. Many appliances such as dishwashers have timers built into them but that feature is rarely used. Customer apathy is still very much a part of life.

But what has really begun to move the needle is the arrival of electric vehicles (EVs). Consumers have begun asking for TVR because they can reduce their cost of charging by more than half. Utilities are more than happy to offer TVR to EV owners since they encourage off-peak charging and avoid the need to invest in expensive peaking capacity.

An additional reason why utilities are interested in moving customers to TVR is the installation of rooftop solar panels (PVs) by customers.

The new generation of TVR are designed with customer lifestyles and convenience in mind. Peak periods are shorter than they used to be, and prices are dropped substantially in a third pricing period, which usually occurs during the night, to encourage the charging of EVs. Lessons have been learned.

[37] Ryan Hledik, "Direct Testimony on behalf of Evergy Missouri West," January 7, 2022. https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=939607385.

As a result, TVR are being offered by more utilities, often accompanied by bill calculators on web portals to help customers pick their best rate. As a sign of the times, a few states have decided to make TVR the default option for their customers and one has made them mandatory.

REFERENCES

Aigner, Dennis (1985). "The Residential Electricity Time-of-Use Pricing Experiments: What Have We Learned?" in Jerry A Hausman and David A. Weiss, editors, *Social Experimentation*, University of Chicago Press, pp. 11-54.

Allcott, Hunt (2011). "Rethinking Real-Time Electricity Pricing." *Resource and Energy Economics*, 33(4): 820-842.

Aubin, Christophe, Denis Fougère, Emmanuel Husson, and Marc Ivaldi (1995). "Real-time pricing of electricity for residential customers: Econometric analysis of an experiment." *Journal of Applied Econometrics* 10: S171–S191.

Barrager, Stephen and Edward Cazalet (2014). *Transactive Energy: A Sustainable Business and Regulatory Model for Electricity*", Baker Street Publishing.

Bolton, D. J. (1938). *Cost and Tariffs in Electricity Supply,* London: Chapman & Hall, Ltd.

Bonbright, James C. (1961). *Principles of Electric Utility Rates*, Columbia University Press.

Borenstein, Severin (2005). "The Long-run Efficiency of Real-Time Pricing." *The Energy Journal*, 26(3): 93-116.

California Public Utilities Commission (2022). "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation." Energy Division White Paper and Staff Proposal. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

Caves, Douglas W., Laurits R. Christensen, and Joseph A. Herriges (1984). "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." *Journal of Econometrics* 26(1–2): 179–203.

Chao, Hung-po (1983). "Peak-Load Pricing and Capacity Planning with Demand and Supply Uncertainty." *Bell Journal of Economics* 14(1): 170-90.

Crew, Michael A. (1994). *Incentive Regulation for Public Utilities*. Springer.

Crew, Michael A., Chitru S. Fernando and Paul R. Kleindorfer (1995). "The Theory of Peak Load Pricing: A Survey." *Journal of Regulatory Economics,* 8: 215-248.

Faruqui, Ahmad, J. Robert Malko (1983). "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy* 8(10): 781–795.

Faruqui, Ahmad, Hung-po Chao, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf (2001). "Analyzing California's Power Crisis." *Energy Journal* 22(4): 29–52.

Faruqui, Ahmad and Stephen S. George (2003). "Demise of PSE's TOU program imparts lessons." *Electric Light & Power* 81(01): 14–15.

Faruqui, Ahmad and Stephen S. George (2005). "Quantifying Customer Response to Dynamic Pricing." *The Electricity Journal*, 18(4): 53-63.

Faruqui, Ahmad and Sanem Sergici (2009). "Household Response to Dynamic Pricing of Electricity – A Survey of 15 Experiments." *Journal of Regulatory Economics*, 38(2): 193-225.

Faruqui, Ahmad, Ryan Hledik, Sanem Sergici (2009). "Piloting the Smart Grid." *The Electricity Journal*, 22(7): 55-69.

Faruqui, Ahmad (2010). "The Ethics of Dynamic Pricing." *The Electricity Journal*, 23(6): 13-27.

Faruqui, Ahmad and Sanem Sergici (2011). "Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment." *Journal of Regulatory Economics,* 40(1): 82-109.

Faruqui, Ahmad, Ryan Hledik, and Jennifer Palmer (2012). "Time-Varying and Dynamic Rate Design," Global Power Best Practice Series, The Regulatory Assistance Project (RAP). https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

Faruqui, Ahmad, Sanem Sergici and Lamine Akaba (2013). "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan." *Energy Efficiency*.

Faruqui, Ahmad, Sanem Sergici and Lamine Akaba (2014). "Dynamic Pricing in a Moderate Climate: The Evidence from Connecticut," with Sanem Sergici and Lamine Akaba, *Energy Journal*, 35:1, pp. 137-160, January.

Faruqui, Ahmad, Sanem Sergici, Neil Lessem, and Dean Mountain (2015). "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," *Energy Economics*, 52, December, pp. 39-48.

Faruqui, Ahmad, Sanem Sergici and Cody Warner (2017). "Arcturus 2.0: A Meta-analysis of TVR for Electricity." *The Electricity Journal*, Volume 30, Issue 10.

Faruqui, Ahmad, Neil Lessem, Sanem Sergici, and Dean Mountain (2017). "The Impact of Time-of-Use Rates in Ontario, *"Public Utilities Fortnightly*, February.

Faruqui, Ahmad (2022). "Ten Lesson in Rate Design: A Meditation," *The Electricity Journal*, Volume 35, Issue 10, December.

Faruqui, Ahmad, Sanem Sergici and Ziyi Tang (2023). "Do Customers Respond to TVR: A Preview of Arcturus 3.0." The Brattle Group. https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf.

Fowlie, Meredith Fowlie, Catherine Wolfram, Patrick Baylis, C Anna Spurlock, Annika Todd-Blick, and Peter Cappers (2021). "Default Effects and Follow-On Behaviour: Evidence from An Electricity Pricing Program." *The Review of Economic Studies*, Volume 88, Issue 6.

Gellings, Clark W. and John H. Chamberlin (1993). *Demand-Side Management: Concepts and Methods*, Fairmont Press, 2nd edition.

George, Stephen S., and Eric Bell (2018). "Key findings from California's Recent Statewide TOU Pricing Pilots." *The Electricity Journal* 31(8) 52-56.

Hausman, William J. and John A. Neufeld (1984). "Time-of-day pricing in the U.S. electric power industry at the turn of the century," *The RAND Journal of Economics*, Vol. 15, No. 1 (Spring), pp. 116-126.

Herter, Karen (2007). "Residential Implementation of Critical-peak Pricing of Electricity." *Energy Policy*, 35(4): 2121-2130.

Herter, Karen, Patrick McAuliffe and Arthur Rosenfeld (2007). "An Exploratory Analysis of California Residential Customer Response to Critical Peak Pricing of Electricity." *Energy*, 32(1): 25-34.

Hogan, William W. (2010). "Fairness and Dynamic Pricing: Comments," The Electricity Journal, Volume 23, Issue 6, July, pp. 28-35.

Houthakker, H. S. (1951). "Electricity Tariffs in Theory and Practice," *The Economic Journal*, Volume 61, 1 March, pp. 1-25.

Joskow, P. L. and C. D. Wolfram (2012). "Dynamic Pricing of Electricity." *American Economic Review*.

Kahn, A.E. (1970). *The Economics of Regulation: Principles and Institutions.* John Wiley & Sons, Inc.: New York.

Lazar, Jim, and Wilson Gonzalez (2015). *Smart Rate Design for a Smart Future.* Regulatory Assistance Project.

Lesgards, Valerie et Edouard Rossat (2022). « Où est passée la 5ème énergie ? L'impératif du signal de la rareté »; *La revue de l'énergie* N° 665 Nov-dec 2022.

Littlechild, Stephen (2003). "Wholesale Spot Price Pass-Through." *Journal of Regulatory Economics*, 23(1): 61-91.

Newsham, Guy R. and Brent G. Bowker (2010). "The Effect of Utility Time-varying Pricing and Load Control Strategies on Residential Summer Peak Electricity Use: A review." *Energy Policy*, 38(7): 3289–96.

Parmesano, Hethie S. and Catherine S. Martin (1983), "The Evolution in U.S. Electric Utility Rate Design," *Annual Review of Energy*, 8:45-94.

Rowlands, Ian H. and Ian M. Furst (2011). "The Cost Impacts of a Mandatory Move to Time-of-use Pricing on Residential Customers: an Ontario (Canada) Case-study," *Energy Efficiency*, 4(4): 571-85.

Schweppe, Fred. (1978). "Power System '2000': Hierarchical control strategies," *IEEE Spectrum*, November.

Schittekatte, Tim, Dharik Mallapragada, Paul L. Joskow, and Richard Schmalensee (2023 forthcoming), "Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing," *Energy Journal*, https://www.iaee.org/energyjournal/article/4151.

Turvey, Ralph (1969). "Marginal Cost." *The Economic Journal*, Volume 79, Issue 314, 1 June 1969, Pages 282–299.

Turvey, Ralph (editor) (1971). *Public Enterprise*, Penguin Modern Economics Readings.

Uhler, Robert G. (1976). "Should Utility Rates be Redesigned," *EPRI Journal*, March, 12-17.

Vickrey, W. S. (1971). "Responsive Pricing of Public Utility Services," *Bell Journal of Economics*, 2(1): 337-46.

Westfield, F M. (1980). "Electric Utility Rate Design Study: Economic Theory of Marginal-cost Pricing and its Application by Electric Utilities in France and Great Britain," EPRI.

Wolak, Frank A. (2007). "Residential Customer Response to Real-time Pricing: The Anaheim Critical Peak Pricing Experiment." Unpublished paper, UC Berkeley.

Wolak, Frank A. (2011). "Do Residential Customers Respond to Hourly Prices: Evidence from a Dynamic Pricing Experiment." *American Economic Review: Papers and Proceedings*, http://www.stanford.edu/group/fwolak/cgibin/sites/default/files/files/hourly_pricing_aer_ paper.pdf.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY
OF
KAREN REIF
VICE PRESIDENT OF RENEWABLES AND ENERGY SOLUTIONS

December 29, 2023

P-11

Table of Contents

I. INTRODUCTION ..... - 1 -

II. THE COMPANY'S CEF-EV PROGRAMS ..... - 2 -

III. COST RECOVERY ..... - 5 -

IV. PROGRESS IN IMPLEMENTING CEF-EV PROGRAMS ..... - 6 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
KAREN REIF
VICE PRESIDENT OF RENEWABLES AND ENERGY SOLUTIONS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Karen Reif. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by Public Service Electric and Gas Company ("PSE&G" or "Company") as Vice President of Renewables and Energy Solutions. I have been employed by PSE&G for 28 years in a number of positions in trading, deregulated subsidiaries, information technology, and continuous improvement. I have held my present position since 2018. My credentials are set forth in Schedule KR-1.

Q. What is the purpose of your testimony?

A. As part of PSE&G's 2023 base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), the purpose of my testimony is to provide information regarding the PSE&G Clean Energy Future – Electric Vehicles ("CEF-EV") program that will support a finding by the Board that the investments and expenditures made by the program are prudent and reasonable. The Company should be permitted to establish rates in this proceeding that will permit recovery of both the CEF-EV costs that the Company proposes to include in to rates and the regulatory asset balances of CEF-EV capital and operation and maintenance ("O&M") costs that have been established in accordance with the Board's January 27, 2021 Order in BPU Docket No.

EO18101111.[1] My testimony will describe the programs and their implementation as well as costs and investments to date and expected during the test period. The details of the Company's accounting and cost recovery are presented in the testimony of witness Michael McFadden. The template for rate adjustments after this rate case proceeding as allowed in the CEF-EV Order are presented in the testimony of witness Mr. Stephen Swetz.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision.

(1) Schedule KR-1 sets forth my credentials;

(3) Schedule KR-2 includes the Company's CEF-EV semi-annual reports as required by the CEF-EV Order.

II. THE COMPANY'S CEF-EV PROGRAMS

Q. Please describe the Company's CEF-EV Program that was approved by the Board in its CEF-EV Order.

A. In 2018, in light of legislative and executive actions in New Jersey supporting electric vehicles, PSE&G filed its CEF-EV program in conjunction with a proposal for energy storage. [2] Subsequently, while PSE&G's program was pending approval, the legislature passed the Plug In Vehicle Act of 2020 directing the Board to adopt policies and programs to advance the adoption

[1] *I/M/O The Petition Of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future – Electric Vehicle And Energy Storage ("CEF-EVES") Program On A Regulated Basis*, BPU Docket No. EO18101111, "Decision and Order Approving Stipulation" (January 27, 2021) ("CEF-EV Order"). The cost recovery mechanism established in that Board Order is discussed in the testimony of Michael McFadden.

[2] New Jersey's 2018 Clean Energy Law (P.L. 2018, c. 17, § 1(a)(2), directed the Board to conduct an analysis of whether implementation of energy storage systems would promote the use of electric vehicles, and Executive Order 28 called for the development of a revised Energy Master Plan to include exploration of methods to incentivize transportation electrification. Additionally at that time New Jersey had recently become a partner in California's zero-emission vehicle program that stipulated that large volume automobile manufacturers achieve a certain percentage of sales from EVs.

of EVs, and the Board issued an order implementing the Act establishing requirements for utility files for light-duty EV charging infrastructure.[3]

In 2021, the CEF-EV Order authorized PSE&G to invest up to $166.2 million in facilities associated with its CEF-EV programs and to incur up to $39 million of incremental O&M expenses, including administrative costs, to support the program. The CEF-EV programs consist of the following three subprograms: (i) a Residential Smart Charging program; (ii) a Level 2 Mixed Use Commercial Charging program; and (iii) a Public Direct Current ("DC") Fast Charging program.[4] The CEF-EV program also provides for cross-program investments for Information Technology ("IT") system upgrades and modifications that support administration of the program.

Q. Please describe the Residential Smart Charging subprogram.

A. The Residential Smart Charging program permits the Company to provide utility incentives to individual residential sites to offset up to $1,500 of the costs of electric facilities required between the utility electric meter and the EV charging stub. The program budget of $60 million is designed to provide make-ready costs for up to 40,000 charging stubs. The Make-Ready work from the meter to the charging station includes the pre-wiring of electrical infrastructure at a parking space or a set of parking spaces to facilitate easy and cost-efficient installation of EV Service Equipment. This program also permits the Company to provide utility incentives of up to $5,000 to offset the costs of making a site Charger-Ready from the utility pole to the meter. This pole-to-meter work includes activities and facilities needed to upgrade an electric service to

[3] PIV Act, P.L. 2019, c.362, codified at N.J.S.A. 48:25-1, *et seq*; *In the Matter of Straw Proposal on Electric Vehicle Infrastructure Build Out*, B.P.U. Docket No. QO20050357 (Order Adopting the Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging, September 23, 2020.

[4] The CEF-EV order holds PSE&G's energy storage proposal and a medium-heavy duty EV program in abeyance pending the Board's consideration of energy storage policy issues and policy for medium-heavy-duty EV charging infrastructure.

accommodate EV service equipment. The budget for this portion of the subprogram is $20 million and is designed to enable the Company to provide incentives at up to 4,000 locations.

Q. Please describe the Mixed Use Commercial Level 2 subprogram.

A. This subprogram is designed to incentivize the installation of 3,500 chargers at 875 sites that include multi-family unit developments, government facilities and public facilities. Under the program PSE&G will provide (i) utility incentives up to $7,500 per charger to cover the make-ready costs of serving up to 3,500 charger stubs up to a total investment of $26.25 million, and (ii) utility incentives to offset up to $10,000 of make-ready electric service upgrades for up to 875 locations, up to a total investment of $8.75 million.

Q. Please describe the Public DC Fast-Charging subprogram.

A. Under this subprogram, PSE&G will provide (i) utility incentives of up to $25,000 per charger of make-ready utility meter to charger stub costs for up to 1,200 fast charger stations, up to a total investment of $30 million, and (ii) utility incentives to offset up to $50,000 of make-ready electric service upgrade costs for up to 300 locations, up to a total investment of $15 million. Of the total $30 million of investments for make-ready utility meter to charger stub work, $5 million is being used to provide demand charge rebates to customers under Rate Schedules GLP and LPL.

Q. Did the CEF-EV Order authorize PSE&G to invest any other EV-related costs in addition to those associated with the three subprograms?

A. Yes. The Company was authorized to invest up to $6.2 million for EV-related IT upgrades.

Q. Did the CEF-EV Order authorize PSE&G to incur any incremental O&M costs?

A. Yes. The Board authorized the Company to incur and defer for future recovery the following O&M costs:

(i) $0.6 million for telematic tracking devices to understand residential charging behaviors of 500 customers;

(ii) $13.8 million for data acquisition costs for all deployed EV chargers for six years;

(iii) $8 million for marketing, education, and outreach to support the EV program; and

(iv) $16.6 million for O&M costs for all administrative services needed to support the EV program, including IT-related O&M.

III. COST RECOVERY

Q. Did the CEF-EV Order establish a method for the Company to account for and recover the costs of the CEF-EV Program?

A. Yes. The CEF-EV Order permitted the Company to establish two regulatory assets that allow it to defer for recovery in this rate case the capital and O&M costs of the CEF-EV program. Under the capital cost deferral, the Company is permitted to defer the capital costs of the CEF-EV program until those costs are rolled into rates in a future base rate case. The CEF-EV Order provided that subject to a prudence review of all CEF-EV costs, the Company's next base rate case would include a request for recovery of all prudently incurred costs associated with the CEF-EV program. Accordingly, in this case, the Company is proposing to recover the CEF-EV regulatory asset on CEF-EV related plant in-service that is or will be placed in service within six months of the end of the test year, as described in the testimony of Michael McFadden and set forth in Schedule MPM-17. Similarly, the Company is proposing recovery of the CEF-capital and O&M regulatory assets, over the same period as set forth in Mr. McFadden's schedule MPM-49.

Q. How did the Company estimate investment levels and costs of the CEF-EV program?

A. The Company estimates these investment and cost levels based on a forecast that models participation levels and growth rates from program inception and uses investment averages per site and per charger for the average number of chargers per site. The costs are based on project costs and participation levels to date with indexes such as inflation and cost of living increases factored into the forecast.

Q. How will the Company recover future CEF-EV program costs?

A. CEF-EV investment that is not likely to be in service by six months following the end of the test year (November 30, 2024), will be deferred and placed in a regulatory asset. Consistent with the CEF-EV Order, this case will remain open so that CEF-EV investments placed in service after November 30, 2024 may be reviewed and placed into rates through annual rate adjustment filings after the Board issues an order at the conclusion of this proceeding. The Company's proposal for the methodology and schedule of the annual rate adjustment filings is set forth in the testimony of Mr. Swetz.

IV. PROGRESS IN IMPLEMENTING CEF-EV PROGRAMS

Q. Please describe implementation of the CEF-EV program.

A. Following the issuance of the CEF-EV Order, PSE&G undertook and completed program development, including development of the IT architecture and coordination with billing processes and systems necessary to administer the program, including EV-specific options such as time-of-use rebates. PSE&G then launched the CEF-EV Program in a series of steps from June through September 2021, that included opening program enrollment applications, issuing demand charge rebates, and marketing and customer education activities.

Q. Following launch, please describe the enrollment levels in the various programs and the investment levels to date.

A. The program has been very successful to date and has exceeded expected enrollment levels for the overall program despite initial delays due in part to supply chain issues. As documented in the most recent semi-annual CEF-EV Program report that is included in Schedule KR-2, through June 2023, enrollments included 5,405 residential customers (5,640 chargers), 72 Mixed Use Commercial customers (143 chargers), and 41 DC fast charger customers (267 chargers). These amounts will be updated in a future Company update.

Q. Has the Company implemented the CEF-EV Program in a reasonable and prudent manner consistent with the CEF-EV Order?

A. Yes. In implementing its CEF-EV program, PSE&G has used first-come, first-served implementation (*i.e.*, not based on geographical area or other preference) to encourage early participation and to eliminate the risk of bias or favoritism. Also, the Company's program application process ensures, consistent with the CEF-EV Order, that all customers or EV stations receiving an incentive must be networked, meaning that the charging station is capable of sending and receiving communications via a wi-fi or cellular network. Moreover, the Company has worked collaboratively with the signatory parties to the Stipulation adopted by the Board in the CEF-EV Order to refine and obtain charging data that has permitted the Company to prepare the residential and non-residential cost-of-service studies that are being presented by Company witness Mr. Swetz in support of corresponding proposed rate changes proposed in this proceeding.

Q. Please describe the Company's approach to customer education, outreach, and marketing activities for the CEF-EV program.

A. PSE&G engaged the services of a marketing consultant to help develop and manage the marketing, education, and outreach of the CEF-EV Program. The vendor collaborates with the

Company to develop annual marketing plans that build upon the success of each previous year to market the program and educate customers most effectively. The overall marketing campaign included developing marketing materials in both digital and print, bill inserts, executing paid media ads, speaking at public conferences and EV-related webinars/seminars, and participating in multiple events such as National Drive Electric Week, Earth Day celebrations, and auto shows. Moreover, PSE&G actively participates in several EV organizations and has participated as speakers or panelists at multiple industry conferences and events.

Q. Is the Company proposing to use any public funding to offset the costs of the CEF-EV Program?

A. In accordance with the CEF-EV Order, PSE&G is committed to helping customers obtain all federal, state or local funding that can be used to offset the cost of the CEF-EV program. PSE&G's CEF-EV program web site's "FAQs" section advises potential participants that PSE&G incentives can be combined with other publicly funded EV incentive programs and includes links to other available State and Federal Programs.[5]

As part of the effort to maximize customers' cross-program participation the Company meets monthly with BPU Staff and the New Jersey Department of Environmental Protection ("NJDEP") to discuss implementation of the EV incentive programs managed by the Office of Clean Energy, NJDEP and the New Jersey Economic Development Authority "(NJEDA") that are available to customers alongside the utility-run programs. These meetings have resulted in the development of cross-promotional materials that have been posted on applicable State websites. Furthermore, PSE&G presented (virtually) to NJZIP stakeholders at a webinar scheduled by

[5] https://nj.myaccount.pseg.com/myservicepublic/electricvehicles

Rutgers University.[6] To the extent that any applicant for PSE&G's CEF-EV program receives public funding that, coupled with the incentives provided under the Company's program, results in a project being funded 90 percent or more, the Company will reduce its incentive funding and rebates to bring the total rebates and incentives under 90 percent of funding costs, though this scenario has rarely occurred.[7]

Q. Are there are any other steps that PSE&G takes to ensure that the costs of CEF-EV programs are reasonable?

A. Yes. PSE&G uses outside vendors to administer certain aspects of the program such as: data acquisition; marketing, education, and outreach; administrative program support; and application processing. When retaining outside vendors, PSE&G used a competitive bid process as part of the Company's procurement process to ensure the costs of procured services are reasonable. Moreover, all CEF-EV Program expenditures are subjected to an internal pre-approval review process that examines the cost prudency and appropriateness of the costs as part of the CEF-EV Program. As part of that process, the Company benchmarks against costs of similar services in other utility-led EV programs.

Q. In addition to the CEF-EV Order, are there other BPU requirements for utility EV incentive programs with which the CEF-EV program complies?

A. Yes. In April, 2023 the BPU issued an order directing the state's electric distribution companies including PSE&G to modify their respective EV programs to comply with the

[6] NJZIP is NJEDA's pilot EV incentive program that provides vouchers for medium-heavy duty EVs. *See* https://www.njeda.gov/njzip/ .

[7] The Company has reviewed 23 applications to date that have indicated receipt of public funding, and has had to reduce PSE&G's incentive on the basis of additional public funding only once. An additional 49 applications are pending review at this time.

requirements of the New Jersey Appliance Standards Law of 2022 (Appliance Act).[8] In compliance with this order, PSE&G added eligibility requirements for CEF-EV Program participants that EV chargers must be Energy Star certified.

Additionally, PSE&G requires program participants to provide charging data that PSE&G reports to the BPU in accordance with the November 2022 and November 2023 orders in the dockets establishing procedures for New Jersey electric distribution companies' basic generation service (BGS) auction requirements.[9]

Q. Does this conclude your direct testimony?

A. Yes. It does.

[8] *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future Electric Vehicle and Energy Storage ("CEF-EVES") Program on a Regulated Basis*, BPU Docket No. EO18101111 (Order dated April 12, 2023). The Appliance Act is codified at N.J.S.A. 52:27D-141.18 – 141.24.

[9] *In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2023* (Decision and Order, November 9, 2022) (requiring EDCs to collect and report charging data from both residential EV and DCFC charging stations including total energy consumed, capacity and transmission tags, measured demands, connected load, and the resulting load factor); *In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2024*, (Decision and Order, November 17, 2023) (requiring EDCs to continue to report on the charging data specified in the prior year's order).

CREDENTIALS
OF
KAREN REIF
VICE PRESIDENT RENEWABLES AND ENERGY SOLUTIONS

My name is Karen Reif, and I am employed by Public Service Electric and Gas Company ("PSE&G", "the Company") as the Vice President of Renewables and Energy Solutions. In this role, I have primary management and oversight responsibility for the market strategy, development and implementation of the Company's solar, electric vehicle, energy storage, and energy efficiency programs.

EDUCATIONAL BACKGROUND

I have a Bachelor of Arts degree in International Studies from Emory University, and a Master of Business Administration in Finance and Strategy from Carnegie Melon University.

WORK EXPERIENCE

I have worked for PSE&G and its affiliate PSEG Services Corporation for 28 years in various positions. I have also worked for ScottMadden Management Consultants as a consultant. I joined PSEG in 1995. I have held multiple positions across the organization including various roles in trading, deregulated subsidiaries, information technology and most recently, continuous improvement. I spent 14 years in the Information Technology Department, holding several leadership roles including system implementation, business relationship management and project management/quality support. Prior to becoming Vice President of Renewables and Energy Solutions, I served as the Senior Director of Continuous Improvement for PSEG Services Corporation. I established this function for PSEG, which is responsible for developing sustainable and quantifiable business improvements based on industry best practices. In July of 2018, I was named Vice President of Renewables and Energy Solutions. My professional experience includes

finance, strategy, business relationships, application implementation, quality assurance, process management and program management.

I have the following certifications: Project Management Professional, Lean Six Sigma, and Information Technology Infrastructure Library Foundation. I was named a 2023 Return on Information New Jersey ("ROI-NJ") Woman in Business Influencer, a 2023 ROI-NJ Energy & Utilities Influencer, a MOVES Power Woman 2022 (New York Moves Magazine), and won the Tribute to Women in NJ ("TWIN") Award in 2015. I am also a board member of the Boys & Girls Club in New Jersey, the Children's Specialized Hospital Foundation, and the Rutgers Business School Advisory Board.

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2021 – January through June 2021

Table of Contents

Section 1: Estimated Quantity of Work 3
Quantity of Work 3
Quantity Completed to Date 3
Section 2: DCFC Distribution Demand Charge Rebate 4
Program Usage 4
Funding Balance 4
Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs 5
Program Forecast 5
Capital Costs 5
O&M Expenses 5
Section 4: Financial Tables 6
Table 1: Summary of Program Investment & Expenses 6
Table 2: Investment by Cost Category 7
Table 3: Investment by Labor, Material & Other Costs 8
Table 4: Expenses by Cost Category 9
Table 5: Expenses by Labor, Material & Other Costs 10

Section 1: Estimated Quantity of Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2021, PSE&G has given no rebates for infrastructure development. PSE&G has invested in IT systems to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding;

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. PSE&G received 8 applications for the DCFC Distribution Demand Charge Rebate on June 30, 2021 that are under review.

Funding Balance

See Table 2 for the balance remaining of the $5 million rebate funding. No DCFC Distribution Demand Charge Rebates were issued this reporting period.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other.

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: Summary of Program Investment & Expenses

Summary of Program Investment & Expenses

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111

Period	*Investment (a)*	*Expenses (b)*	*Total (c=a+b)*
H1 2021	**$89,635**	**$723,093**	**$812,727**
January	$0	$0	**$0**
February	$0	$0	**$0**
March	$0	$337,327	**$337,327**
April	$0	$65,997	**$65,997**
May	$20,494	$180,627	**$201,120**
June	$69,141	$139,142	**$208,282**
Period-to-Date	**$89,635**	**$723,093**	**$812,727**
Program-to-Date	**$89,635**	**$723,093**	**$812,727**
To-Go Forecast	**$166,110,365**	**$38,243,474**	**$38,153,840**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$38,966,567**
Program Caps	$166,200,000	$38,966,567	$38,966,567

CEF – EV Program
H1-2021 - January through June 2021

PSE&G

Table 2: Investment by Cost Category

Program Investment by Cost Category

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	*Make Ready: Pole-to-Meter (a)*	*Make Ready: Behind-the-Meter (b)*	*Demand Charge Rebate (c)*	*IT Systems (d)*	*Total Investment for Reporting Period (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$0	$0	$0	$0	$0
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$0	$0	$0	$0	$0
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$0	$0	$0	$0
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$89,635	$89,635
TOTAL INVESTMENT BY CATEGORY	$0	$0	$0	$89,635	$89,635
PROGRAM CAPS BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
REMAINING FUNDING BY CATEGORY	$43,750,000	$111,250,000	$5,000,000	$6,110,365	$166,110,365

CEF – EV Program
H1-2021 - January through June 2021

Table 3: Investment by Labor, Material & Other Costs

Program Investment LM&O

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total Expenses (d=a+b+c)*
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$0	$0	$0	$0
April	$0	$0	$0	$0
May	$18,164	$0	$2,330	$20,494
June	$56,374	$0	$12,767	$69,141
Period Total	**$74,538**	**$0**	**$15,097**	**$89,635**

CEF – EV Program
H1-2021 - January through June 2021

Table 4: Expenses by Cost Category

Program Expenses by Cost Category

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

Program/Budget Line	*Administration & Program Development (a)*	*Marketing, Education & Outreach (b)*	*Data Acquisition (c)*	*Residential Vehicle Device Technical Trial (d)*	*Total Expenses for Reporting Period (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$299,186	$1,067	$21,018	$0	$321,271
MIXED USE / COMMERICAL L2					
Mixed Use Commerical Subtotal	$107,228	$903	$0	$0	$108,131
DCFC PUBLIC CHARGING					
DCFC Subtotal	$131,554	$1,067	$0	$0	$132,621
IT SYTEMS					
IT Systems Subtotal	$128,598	$0	$32,471	$0	$161,069
TOTAL EXPENSES BY CATEGORY	$666,567	$3,037	$53,489	$0	$723,093
PROGRAM CAPS BY CATEGORY	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other Costs

Program Expenses LM&O

Utility Name: PSE&G
Program Name: Clean Energy Future - Electric Vehicles
BPU Docket No. EO18101111
Reporting Period: January 1, 2021 thru June 30, 2021

2021	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total Expenses (d=a+b+c)*
January	$0	$0	$0	$0
February	$0	$0	$0	$0
March	$77,327	$0	$260,000	$337,327
April	$59,247	$0	$6,750	$65,997
May	$58,909	$0	$121,718	$180,627
June	$77,958	$0	$61,184	$139,142
Period Total	**$273,441**	**$0**	**$449,651**	**$723,093**

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2021 – July through December 2021

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work 3
Quantity of Work 3
Quantity Completed to Date 3
Section 2: DCFC Distribution Demand Charge Rebate 4
Program Usage 4
Funding Balance 4
Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs 5
Program Forecast 5
Capital Costs 5
O&M Expenses 5
Section 4: Financial Tables 6
Table 1: CEF-EV Program Summary 6
Table 2: Investment by Cost Category 7
Table 3: Investment by Labor, Materials & Other ("LM&O") Costs 8
Table 4: Program Expenses by Cost Category 9
Table 5: Expenses by Labor, Material & Other ("LM&O") Costs 10

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September, 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of December 31, 2021, PSE&G has invested a total of $4.2M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Through December 31, 2021, PSE&G has enrolled 32 customers to the DCFC Distribution Demand Charge Rebate.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of December 31, 2021, PSE&G distributed $292,680 in demand charge rebates for this reporting period. There is $4.7M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of December 31, 2021, the CEF Program has enrolled 218 residential customers, 5 Mixed Use Commercial customers, and 32 DCFC customers in the CEF-EV Program.

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Period	*Investment (a)*	*Expenses (b)*	*Total (c=a+b)*
July	$534,212	$93,260	**$627,472**
August	$828,890	$143,407	**$972,298**
September	$216,220	$173,913	**$390,133**
October	$542,813	$73,084	**$615,896**
November	$490,443	$67,845	**$558,288**
December	$1,526,801	$50,449	**$1,577,249**
Reporting Period	**$4,139,378**	**$601,958**	**$4,741,336**
Program-to-Date	**$4,229,013**	**$1,325,051**	**$5,554,064**
To-Go Forecast	**$161,970,987**	**$37,641,516**	**$199,612,503**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – EV Program
H2-2021 – July through December 2021

Table 2: Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter (a)*	*Make Ready: Behind the Meter (b)*	*Demand Charge Rebate (c)*	*IT Systems (d)*	*Total (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$0	$159,016	$0	$0	$159,016
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$0	$37,500	$0	$0	$37,500
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$0	$292,680	$0	$292,680
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$3,650,182	$3,650,182
Reporting Period	**$0**	**$196,516**	**$292,680**	**$3,650,182**	**$4,139,378**
Program-to-Date	$0	$196,516	$292,680	$3,739,817	$4,229,013
Remaining Funding by Category	$43,750,000	$111,053,484	$4,707,320	$2,460,183	$161,970,987
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – EV Program
H2-2021 – July through December 2021

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

Period	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total (d=a+b+c)*
July	$76,965	$0	$457,247	$534,212
August	$80,379	$0	$748,511	$828,890
September	$94,513	$0	$121,706	$216,220
October	$58,789	$0	$484,023	$542,813
November	$40,847	$0	$449,596	$490,443
December	$109,565	$0	$1,417,235	$1,526,801
Reporting Period	**$461,059**	**$0**	**$3,678,319**	**$4,139,378**

CEF – EV Program
H2-2021 – July through December 2021

Table 4: Program Expenses by Cost Category

Program/Budget Line	*Administration & Program Development (a)*	*Marketing, Education, and Outreach (b)*	*Data Acquisition (c)*	*Residential Vehicle Device Technical Trial (d)*	*Total (e=a+b+c+d)*
RESIDENTIAL					
Residential Subtotal	$237,875	$58,545	$46,487		**$342,907**
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$116,739	$21,598	$0		**$138,337**
DCFC PUBLIC CHARGING					
DCFC Subtotal	$105,697	$21,522	$0		**$127,219**
IT SYSTEMS					
IT Systems Subtotal	-$15,975	$0	$9,471		**-$6,504**
Reporting Period	**$444,336**	**$101,664**	**$55,958**	**$0**	**$601,958**
Program-to-Date	$1,110,903	$104,701	$109,447	$0	$1,325,051
Remaining Funding by Category	$15,509,097	$7,895,299	$13,667,120	$570,000	$37,641,516
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – EV Program
H2-2021 – July through December 2021

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

2021	*Labor (a)*	*Materials (b)*	*Other (c)*	*Total Expenses (d=a+b+c)*
July	$102,181	$64	-$8,985	$93,260
August	$112,236	$21,956	$9,215	$143,407
September	$109,692	$0	$64,221	$173,913
October	$97,684	$0	-$24,600	$73,084
November	$31,840	$0	$36,005	$67,845
December	$57,390	$935	-$7,876	$50,449
Reporting Period	**$511,023**	**$22,955**	**$67,980**	**$601,958**

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H1-2022 – January through June 2022

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work 3
Quantity of Work 3
Quantity Completed to Date 3
Section 3: DCFC Distribution Demand Charge Rebate 4
Program Usage 4
Funding Balance 4
Section 2: Semi-Annual and Program To-Date Forecast and Actual Costs 5
Program Forecast 5
Capital Costs 5
O&M Expenses 5
Section 4: Financial Tables 6
Table 1: CEF-EV Program Summary 6
Table 2: Investment by Cost Category 7
Table 3: Investment by Labor, Materials & Other (“LM&O”) Costs 8
Table 4: Program Expenses by Cost Category 9
Table 5: Expenses by Labor, Material & Other (“LM&O”) Costs 10

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: As of June 30, 2020, PSE&G has invested a total of $7.3M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 3: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 33 customers to the DCFC Distribution Demand Charge Rebate, comprising of 242 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. As of June 30, 2022, PSE&G distributed $482,768 in demand charge rebates for this reporting period. There is $4.5M remaining in the funding.

Section 2: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. As of June 30, 2021, the CEF Program has enrolled 670 residential customers (678 Chargers), 11 Mixed Use Commercial customers (17 Chargers), and 33 DCFC customers in the CEF-EV Program (242 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H1 2022	**$3,108,316**	**$964,393**	**$4,072,709**
January	$716,318	$90,893	**$807,211**
February	$601,843	$153,420	**$755,263**
March	$609,068	$181,442	**$790,510**
April	$319,678	$188,446	**$508,124**
May	$567,202	$92,147	**$659,349**
June	$303,744	$258,045	**$561,789**
Period-to-Date	**$3,117,853**	**$964,393**	**$4,082,246**
Program-to-Date	**$7,238,549**	**$2,289,444**	**$9,527,993**
To-Go Forecast	**$158,961,451**	**$36,677,123**	**$195,638,574**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$0	$684,491	$0	$0	$684,491
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$0	$84,980	$0	$0	$84,980
DCFC PUBLIC CHARGING					
DCFC Subtotal	$0	$49,950	$190,088	$0	$240,038
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$2,108,344	$2,108,344
Reporting Period	**$0**	**$819,421**	**$190,088**	**$2,108,344**	**$3,117,853**
Program to Date	$0	$1,015,937	$482,768	$5,848,161	$7,346,866
Remaining Funding by Category	$43,750,000	$110,234,063	$4,517,232	$351,839	$158,853,134
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	*Labor*	*Materials*	*Other (Incentives, O/S, AFUDC)**	*Total Investment*
January	$42,931	$0	$673,387	**$716,318**
February	$32,290	$0	$569,553	**$601,843**
March	$11,930	$0	$597,137	**$609,068**
April	$13,837	$0	$305,841	**$319,678**
May	$5,278	$0	$561,924	**$567,202**
June	$5,996	$0	$297,748	**$294,207**
Reporting Period	**$112,262**	**$0**	**$3,005,590**	**$3,117,852**

*O/S = Outside Services, AFUDC = Allowed Funds Used During Construction

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$347,596	$64,420	$20,753	$0	**$432,769**
Mixed-Use Subtotal	$124,520	$35,960	$17,524	$0	**$178,004**
DCFC Subtotal	$118,261	$34,578	$13,516	$0	**$166,355**
IT Systems Subtotal	$0	$0	$187,264	$0	**$187,264**
Reporting Period	**$590,377**	**$134,958**	**$239,058**	**$0**	**$964,393**
Program to Date	$1,701,280	$239,659	$348,504	$0	$2,289,443
Remaining Funding by Category	$14,918,720	$7,760,341	$13,428,063	$570,000	$36,677,127
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
January	$90,893	$0	$0	$90,893
February	$153,420	$0	$0	$153,420
March	$181,443	$0	$0	$181,443
April	$184,903	$0	$3,543	$188,446
May	$91,022	$0	$1,125	$92,147
June	$252,631	$0	$5,413	$258,044
Period Total	**$954,312**	**$0**	**$10,081**	**$964,393**

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

H2-2022 – July through December 2022

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work 3
Quantity of Work 3
Quantity Completed to Date 3
Section 2: DCFC Distribution Demand Charge Rebate 4
Program Usage 4
Funding Balance 4
Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs 5
Program Forecast 5
Capital Costs 5
O&M Expenses 5
Section 4: Financial Tables 6
Table 1: CEF-EV Program Summary 6
Table 2: Investment by Cost Category 7
Table 3: Investment by Labor, Materials & Other ("LM&O") Costs 8
Table 4: Program Expenses by Cost Category 9
Table 5: Expenses by Labor, Material & Other ("LM&O") Costs 10

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial L2, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology (IT) architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021 as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: Program to date, PSE&G has invested a total of $13M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021 with credits issued retroactive to program approval on January 27, 2021. Program to date, PSE&G has enrolled 35 customers to the DCFC Distribution Demand Charge Rebate, comprising of 252 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. Program to date, PSE&G distributed $628,777 in demand charge rebates, of which $210,532 was distributed this reporting period. There is $4.4M remaining in the funding. Year 3 of the credit will begin on January 27, 2023, with the distribution demand charge rebate adjusted from 75% to 50%.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021.

Program to date, the CEF Program has enrolled 1,974 residential customers (1,995 Chargers), 33 Mixed Use Commercial customers (63 Chargers), and 35 DCFC customers in the CEF-EV Program (252 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: Financial Tables

Table 1: CEF-EV Program Summary

Summary of Program Investment & Expenses

Period	*Investment*	*Expenses*	*Total*
H2 2022	**$5,695,131**	**$1,710,798**	**$7,405,929**
July	$1,105,954	$743,625	**$1,849,579**
August	$397,345	$211,971	**$609,316**
September	$1,022,141	$207,177	**$1,229,318**
October	$1,008,309	$187,788	**$1,196,097**
November	$819,372	$160,819	**$980,191**
December	$1,338,213	$199,418	**$1,537,631**
Period-to-Date	**$5,695,131**	**$1,710,798**	**$7,405,929**
Program-to-Date	**$12,988,098**	**$4,000,242**	**$16,988,340**
To-Go Forecast	**$153,211,902**	**$34,966,325**	**$188,178,227**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 2: Investment by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$1,929,859	$1,660,600	$0	$0	$3,590,459
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$61,386	$366,843	$0	$0	$428,229
DCFC PUBLIC CHARGING					
DCFC Subtotal	$888,648	$200,000	$210,532	$0	$1,299,180
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$377,264	$377,264
Reporting Period	**$2,879,893**	**$2,227,442**	**$210,532**	**$377,264**	**$5,695,131**
Program to Date	$2,879,893	$3,305,000	$628,777	$6,174,428	$12,988,098
Remaining Funding by Category	$40,870,107	$107,945,000	$4,371,223	$25,572	$153,211,902
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2022	Labor	Materials	Other (Incentives, O/S)*	Total Investment
July	$4,192	$0	$1,105,954	**$1,110,146**
August	$2,034	$0	$395,311	**$397,345**
September	$1,224	$0	$1,022,141	**$1,023,365**
October	$122	$0	$1,008,187	**$1,008,309**
November	$46	$0	$819,372	**$819,418**
December	$0	$0	$1,342,010	**$1,342,010**
Reporting Period	**$7,617**	**$0**	**$5,687,514**	**$5,695,131**

*O/S = Outside Services,

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 4: Program Expenses by Cost Category

Reported Program Investment by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$395,572	$178,088	$18,074	$0	**$591,733**
Mixed-Use Subtotal	$166,956	$48,414	$17,159	$0	**$232,529**
DCFC Subtotal	$148,432	$46,208	$11,987	$0	**$206,627**
IT Systems Subtotal	$0	$0	$679,808	$0	**$679,808**
Reporting Period	**$710,961**	**$272,709**	**$727,028**	**$0**	**$1,710,798**
Program to Date	$2,412,241	$512,368	$1,075,532	$0	$4,000,241
Remaining Funding by Category	$13,787,759	$7,487,632	$12,701,035	$570,000	$34,966,326
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – Electric Vehicle (EV) Program
H2-2022 – July through December 2022

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other*	*Total Expenses*
July	$234,911	$0	$508,713	$743,625
August	$211,308	$0	$663	$211,971
September	$205,764	$0	$1,413	$207,177
October	$187,302	$0	$486	$187,788
November	$159,684	$0	$1,134	$160,819
December	$195,731	$0	$3,688	$199,418
Period Total	**$1,194,700**	**$0**	**$516,098**	**$1,710,798**

Clean Energy Future – Electric Vehicle (EV) Program

Semi-Annual Report to the Board of Public Utilities

HY1-2023 – January through June 2023

Table of Contents

Section 1: Estimated Quantity of Make-Ready Work 3
Quantity of Work 3
Quantity Completed to Date 3
Section 2: DCFC Distribution Demand Charge Rebate 4
Program Usage 4
Funding Balance 4
Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs 5
Program Forecast 5
Capital Costs 5
O&M Expenses 5
Section 4: EV Charging Data Summary 6
Residential EV Charging Data 6
DCFC Data Definitions 6
Section 5: Tables 7
Table 1: CEF-EV Program Financial Summary 7
Table 2: Investment by Cost Category 8
Table 3: Investment by Labor, Materials & Other ("LM&O") Costs 9
Table 4: Program Expenses by Cost Category 10
Table 5: Expenses by Labor, Material & Other ("LM&O") Costs 11
Table 6: Residential EV Charging Data Summary 12
Table 7: DCFC EV Charging Data Summary 13

Section 1: Estimated Quantity of Make-Ready Work

PSE&G will provide semi-annual reports on the CEF-EV deployment ("CEF-EV Report") with the following information:

- Estimated quantity of work
- Quantity completed to date or, if the project cannot be quantified with numbers, the major tasks completed, e.g. Residential, Mixed Use Commercial, and DCFC Public Charging Make Ready to Charger Stub units completed and number of service upgrades:

Quantity of Work

See Table 1 for a summary of the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the Clean Energy Future – Electric Vehicle Program ("CEF-EV Program").

Major Tasks Completed: Following Board approval on January 27, 2021, PSE&G initiated program development, including Infrastructure Technology ("IT") architecture. PSE&G launched the CEF-EV Program in a series of steps from June through September 2021. Since that time PSE&G has continued to enroll eligible customers as discussed in detail in each subprogram below.

Quantity Completed to Date

See Table 2 for the capital costs per subprogram, indicating the work completed to date.

Quantity Completed: Since program inception, PSE&G has invested a total of $21M in CEF-EV Program investment. This includes investment for the following three subprograms: (i) Residential Smart Charging Program, (ii) Level-2 Mixed Use Charging Program, and (iii) a Direct Current Fast Charging ("DCFC") Program, which also includes investment in Distribution Demand Charge Rebates. The CEF-EV Program further includes cross-program investments for IT system upgrades to support the deployment of the CEF-EV program and the development of associated customer platforms.

Section 2: DCFC Distribution Demand Charge Rebate

The semi-annual reports will include the following information:

- The usage of the rebate funding
- The balance remaining of the $5 million rebate funding

Program Usage

The application and agreement form for the DCFC Distribution Charge Rebate for pre-existing sites was launched on June 15, 2021. Program to date, PSE&G has enrolled 41 customers to the DCFC Distribution Demand Charge Rebate, comprising of 267 chargers.

Funding Balance

See Table 2 for the usage and balance remaining of the $5 million rebate funding. Since program inception, PSE&G distributed $780,571 in demand charge rebates. There is $4.2M remaining in the funding.

Section 3: Semi-Annual and Program To-Date Forecast and Actual Costs

The semi-annual reports will include the following information:

- The forecasted and actual capital costs
- The forecasted and actual O&M expenses

The project expenditures shall be broken out between labor, material, and other costs.

Program Forecast

See Table 1 for the period-to-date, program-to-date, and forecasted capital costs and O&M expenses for the CEF-EV Program.

Capital Costs

See Table 2 for the actual capital costs by cost category and Table 3 for the capital costs broken out between labor, material and other ("LM&O").

Program enrollment for make-ready funding was implemented in phases. The DCFC subprogram was launched on July 23, 2021. The Level 2 Mixed-Use Commercial subprogram was launched on July 30, 2021. The Residential make-ready subprogram was launched on September 15, 2021. Since program inception, the CEF Program has enrolled 5,405 residential customers (5,640 Chargers), 72 Mixed Use Commercial customers (143 Chargers), and 41 DCFC customers in the CEF-EV Program (267 Chargers).

O&M Expenses

See Table 4 for the actual expenses by cost category and Table 5 for the expenses broken out between labor, material and other.

Section 4: EV Charging Data Summary

The CEF-EV Program semi-annual report will include a submittal of the following data:

- Residential EV Charging Data
- Direct Current Fast Charging ("DCFC") Data

The submittal will provide the total energy consumed, capacity and transmission tags, measured demands, connected load, and the resulting load factor.

Residential EV Charging Data

The Residential EV charging data is summarized in Table 6.

DCFC Data Definitions

The DCFC EV charging data is summarized in Table 7.

Section 5: Tables

Table 1: CEF-EV Program Financial Summary

Period	*Investment*	*Expenses*	*Total*
HY1 2023	**$7,992,376**	**$2,515,249**	**$10,507,625**
January	$874,051	$1,020,473	**$1,894,524**
February	$1,274,173	$30,279	**$1,304,452**
March	$932,227	$468,444	**$1,400,671**
April	$1,553,476	$335,997	**$1,889,473**
May	$1,680,830	$308,856	**$1,989,686**
June	$1,677,619	$351,201	**$2,028,820**
Period-to-Date	**$7,992,376**	**$2,515,249**	**$10,507,625**
Program-to-Date	**$20,980,474**	**$6,515,491**	**$27,495,965**
To-Go Forecast	**$145,219,526**	**$32,451,076**	**$177,670,602**
Total Program Forecast	**$166,200,000**	**$38,966,567**	**$205,166,567**
Program Caps	$166,200,000	$38,966,567	$205,166,567

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 2: Investment by Cost Category

Program/Budget Line	*Make Ready: Pole to Meter*	*Make Ready: Behind the Meter*	*Demand Charge Rebate*	*IT Systems*	*Total Investment for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$2,273,203	$4,471,157	$0	$0	$6,744,360
MIXED USE / COMMERICAL L2					
Mixed-Use Subtotal	$71,230	$604,597	$0	$0	$675,827
DCFC PUBLIC CHARGING					
DCFC Subtotal	$71,586	$324,870	$151,795	$0	$548,251
IT SYSTEMS					
IT Systems Subtotal	$0	$0	$0	$23,938	$23,938
Reporting Period	**$2,416,018**	**$5,400,625**	**$151,795**	**$23,938**	**$7,992,376**
Program to Date	$5,295,912	$8,705,761	$780,571	$6,198,366	$20,980,610
Remaining Funding by Category	$38,454,088	$102,544,239	$4,219,429	$1,634	$145,219,390
Total Program Forecast	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000
Program Caps by Category	$43,750,000	$111,250,000	$5,000,000	$6,200,000	$166,200,000

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 3: Investment by Labor, Materials & Other ("LM&O") Costs

2023	*Labor*	*Materials*	*Other**	*Total Investment*
January	$3,928	$0	$870,123	**$874,051**
February	$9,990	$0	$1,264,183	**$1,274,173**
March	$8,914	$0	$923,313	**$932,227**
April	$-9	$0	$1,553,485	**$1,553,476**
May	$0	$0	$1,680,830	**$1,680,830**
June	$0	$0	$1,677,619	**$1,677,619**
Reporting Period	**$22,823**	**$0**	**$7,969,553**	**$7,992,376**

*Other = Incentives and Outside Services ("O/S")

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 4: Program Expenses by Cost Category

Program/Budget Line	*Administration & Program Development*	*Marketing, Education, and Outreach*	*Data Acquisition*	*Residential Vehicle Device Technical Trial*	*Total Expenses for Reporting Period*
RESIDENTIAL					
Residential Subtotal	$478,144	$276,712	$1,113,363	$0	**$1,868,219**
Mixed-Use Subtotal	$167,101	$50,130	$11,992	$0	**$229,222**
DCFC Subtotal	$158,567	$74,650	$7,221	$0	**$240,438**
IT Systems Subtotal	$0	$0	$177,370	$0	**$177,370**
Reporting Period	**$803,811**	**$401,492**	**$1,309,946**	**$0**	**$2,515,249**
Program to Date	$3,102,475	$913,860	$2,498,101	$0	$6,514,436
Remaining Funding by Category	$13,517,525	$7,086,140	$11,278,466	$570,000	$32,452,131
Total Program Forecast	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567
Program Caps by Category	$16,620,000	$8,000,000	$13,776,567	$570,000	$38,966,567

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 5: Expenses by Labor, Material & Other ("LM&O") Costs

Period	*Labor*	*Materials*	*Other**	*Total Expenses*
January	$1,019,774	$0	$699	$1,020,473
February	$29,554	$0	$724	$30,279
March	$468,102	$0	$342	$468,444
April	$329,837	$0	$6,160	$335,997
May	$307,971	$0	$885	$308,856
June	$348,047	$0	$3,154	$351,201
Period Total	**$2,503,285**	**$0**	**$11,964**	**$2,515,249**

*Other = Incentives and Outside Services ("O/S")

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 6: Residential EV Charging Data Summary

Period	*Off-Peak kWh's*	*On-Peak kWh's*	*Grand Total kWh's*
January	337,366	75,312	412,678
February	304,691	58,513	363,204
March	468,153	74,391	542,544
April	434,899	67,780	502,679
May	536,972	79,060	616,032
June	761,527	118,402	879,929
Period Total	**2,843,608**	**473,458**	**3,317,066**

kWh's=Kilowatt-Hours

CEF – Electric Vehicle (EV) Program
HY1-2023 – January through June 2023

Table 7: DCFC EV Charging Data Summary

Using the 12-month period of July 2022 through June 2023					
Data	***Units***	***Total***	***Minimum***	***Average***	***Maximum***
Total Energy Consumed	kWh	30,463,996	8,621	952,000	2,685,425
Connected Load	kW	28,390	100	887	2,250
Load Factor	%		0%	18%	45%
Average Summer Demand	kW		48	423	1,128
Average Annual Demand	kW		48	414	1,112
PJM Capacity Obligation 1	kW	*January 1 – May 31*	0	125	428
PJM Capacity Obligation 2	kW	*June 1 – September 30*	3	214	722
PJM Capacity Obligation 3	kW	*October 1 – December 31*	0	125	429
PSEG Trans Obligation	kW		3	192	529

KW=Kilowatt; kWh=Kilowatt-Hour

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 17 Electric and B.P.U.N.J. No. 17 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief

BPU Docket Nos. _____

DIRECT TESTIMONY

OF

DAVID JOHNSON
VICE PRESIDENT – CUSTOMER CARE AND CHIEF CUSTOMER OFFICER, PSE&G

December 29, 2023

P-12

Table of Contents

I. INTRODUCTION .....- 1 -

II. THE COMPANY'S CEF-EC PROGRAM AND CURRENT STATUS .....- 2 -

III. BENEFITS OF CEF-EC PROGRAM INVESTMENTS.....- 5 -

IV. ACCOUNTING AND COST RECOVERY FOR CEF-EC PROGRAM.....- 15 -

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
DAVID JOHNSON
VICE PRESIDENT – CUSTOMER CARE AND
CHIEF CUSTOMER OFFICER PSE&G

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David Johnson. My business address is 80 Park Plaza, Newark, New Jersey, 07102.

Q. In what capacity are you employed?

A. I am currently employed by Public Service Electric and Gas Company ("PSE&G" or "Company") as Vice President Customer Care and Chief Customer Officer (COO). I have over 25 years of experience in customer service for energy providers. For example, I previously served as CCO for Duquesne Light Company in Pittsburgh, PA, Vice President for Customer Service at Entergy Louisiana and Senior Vice President of Customer Service at DTE Energy. In my current role, I am responsible for the successful deployment of the CEF-EC program and operationalizing the AMI capabilities that result from this program. Implementation of the CEF-EC program and AMI functionalities involve many of the areas that I oversee including billing, meter reading, collections, customer experience and the contact center.

Q. What is the purpose of your direct testimony?

A. As part of PSE&G's 2023 base rate filing with the New Jersey Board of Public Utilities ("BPU" or "Board"), the purpose of my testimony is to provide information that will support a finding by the Board that the investments and expenditures made by PSE&G for its Clean Energy Future – Energy Cloud ("CEF-EC") program are prudent and reasonable. The CEF-EC costs that

the Company proposes to recover in this proceeding are the investments placed in service by November 30, 2024, six months after the end of the test year, as well as the regulatory asset balances of the CEF-EC Infrastructure Deferral, Stranded Cost Deferral and Operation and Maintenance ("O&M") regulatory assets that have been established in accordance with the Board's January 7, 2021 Order in BPU Docket No. EO18101115 that authorized the CEF-EC program and establishment of the CEF-EC regulatory assets.[1] The accounting and cost recovery for the program and the treatment of depreciation are described in the testimony of Company witness Mr. Michael McFadden.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision.

(1) Schedule DJ-1 sets forth my credentials;

(2) Schedule DJ-2 provides the CEF-EC semi-annual reports that have been submitted to BPU Staff to date.

II. THE COMPANY'S CEF-EC PROGRAM AND CURRENT STATUS

Q. Please describe the Company's CEF-EC Program that was approved by the Board in its CEF-EC Order.

A. By Order dated February 19, 2020, the Board found that AMI is a means to achieve the objectives of the 2019 Energy Master Plan ("EMP").[2] Accordingly, the Board directed PSE&G

[1] *I/M/O The Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future – Energy Cloud ("CEF-EC") Program on a Regulated Basis*, BPU Docket No. EO18101115, "Decision and Order Approving Stipulation" (January 7, 2021) ("CEF-EC Order").

[2] *In re the Petition of Rockland Electric Company for Approval of an Advanced Metering Program, and for Other Relief*, BPU Docket No. ER16060524 (February 19, 2020).

and other utilities to file petitions for AMI implementation. In the CEF-EC Order, the Board authorized the Company to install approximately 2.2 million Advanced Meter Infrastructure ("AMI") meters at an estimated investment cost of up to $707 million for the advanced meters, network infrastructure and associated information technology required to implement Release 1 of the CEF-EC program. The Company planned to install AMI meters over the period 2021 to 2024 in accordance with the following schedule:

2021	80,000 meters
2022	300,000 meters
2023	900,000 meters
2024	900,000 meters

Under the CEF-EC Order the Company had the right to accelerate this deployment schedule to effectuate the efficient deployment of AMI meters. The Company began installing AMI meters during 2021 and 2022 according to this plan and, beginning in 2023, conducted an accelerated geographic strategic deployment in which the Company divided its service territory into three separate regions and employed a strategy to identify and group meters for replacement on a daily basis. The Company utilized its existing manual meter reading assignments to develop a deployment strategy to support the efficient deployment of AMI meters and consolidation of meter reading assignments.

Q. What is the current status of PSE&G's AMI installation project?

A. The project is currently ahead of its installation schedule and under the program budget.

Q. What is the status of the AMI network installation and functionality?

A. The Company completed installation of its Landis + Gyr Network ("Network") in June 2022, and 100 percent of the Network was communicating by September of 2022.

Q. How many AMI meters have been installed so far?

A. As of November 30, 2023, 1,270,091 residential and 178,615 commercial AMI meters have been installed, for a total of 1,448,706. Thus, the Company has already exceeded the planned installation of 1,280,000 AMI meters by the end 2023 that is included in the CEF-EC Order. Installations are expected to continue ahead of pace.

Q. Is the Company projecting to complete full AMI deployment within six months beyond the end of the rate case test year (by November 30, 2024)?

A. At this time, yes, PSE&G projects full deployment will be accomplished by November 30, 2024, and possibly could be accomplished earlier.[3] Certain factors that are difficult to predict may impact the timing, such as new supply chain issues, or other issues impacting PSE&G's ability to obtain AMI meter inventory or impacting the labor force. Based on current conditions, the Company expects to finish ahead of schedule.

Q. What are program costs compared to the program forecast as of September 30, 2023?

A. Total actual costs as of September 30, 2023 were approximately $310 million (approximately $278 million for capital and $32 million for O&M). PSE&G forecasts total costs of the Program upon completion in November 2024 to be $625 million (approximately $570 million for capital and $55 million for O&M) well below the approved amount of up to $779 million ($707 for capital and $72 for O&M).

Q. How has PSE&G managed implementation of the CEF-EC program to deliver the program to date significantly under the forecast budget?

A. PSE&G has achieved numerous meter deployment efficiencies by implementing the following strategies.

[3] With the exception of customers who elect to opt out of an AMI meter.

Successful customer communications ahead of meter changes has resulted in an approximate 90% success rate of changing the meter on the first visit. Making only a single visit to a customer location has reduced the need for appointments and unscheduled visits, which, by nature, are less productive and more costly.

Additionally, PSE&G has worked closely with the meter installation vendor to optimize meter change routes. The meter change schedule was organized by "sectors," which are geographic areas. Each sector was carefully designed to reduce travel time both within each sector and to the various warehouses and laydown yards.

PSE&G's internal workforce has also taken advantage of "opportunistic" meter changes on customers' premises. In other words, as PSE&G has been visiting customer homes to address meter-related issues, such as non-registering meters or high bill complaints, PSE&G has taken the opportunity to replace the existing meter with an AMI meter at that visit. This eliminates the need for a separate, future visit just to change that customer's meter.

III. BENEFITS OF CEF-EC PROGRAM INVESTMENTS

Q. Recognizing that the Company has not concluded the implementation of its CEF-EC program, have the benefits of the program identified previously by PSE&G begun to be realized?

A. Yes. PSE&G's CEF-EC program strategy prioritized delivering the benefits of AMI meters to customers as soon as possible following AMI meter installation. The program currently is delivering substantial benefits to customers. Some benefits have been, or are expected to be, achieved ahead of the forecast schedule for delivery.

Q. Please generally explain AMI customer benefits and the expected timing of achieving these benefits.

A. As a result of PSE&G's CEF-EC program deployment design, some customer benefits are already active, such as billing on actual usage transmitted by the AMI meters, and remote capabilities such as move in/move out and disconnect/reconnect.

Additionally, as set forth in the CEF-EC Order, other benefits are achievable over longer periods. In the October 11, 2018 filing to implement the CEF-EC program, the Company proposed a program that would implement 22 out of a total of 70 potential AMI functionalities or "Use Cases" that focused on customer engagement, network operations and planning, and new utility products and services.[4] PSE&G committed in the stipulation of settlement approved by the CEF-EC Order to use "best efforts" to provide the AMI capabilities of the 22 Use Cases within the approved program budget, and the parties recognized that, "these capabilities may not be available until after the full deployment if the AMI meters is complete."[5]

Notwithstanding, PSE&G's CEF-EC program to date has already accomplished deployment of multiple Use Cases that benefit all customers by improving the efficiency of operations and reducing truck dispatches that would previously have been required to perform move in/move out and reconnects.

[4] Those 22 use cases were referred to as "Release 1." *See* CEF-EC Order at Stipulation ¶ 3. The remaining 48 Use Cases were generally described in PSE&G's AMI cost-benefit analysis that accompanied its 2018 filing, and could be proposed as part of future program proposal filings but are not included in the budget or implementation of the currently approved CEF-EC Program.

[5] CEF-EC Order at Stipulation ¶ 17.

Q. Beginning with the most basic AMI functions, when AMI meters are installed, when does data begin to communicate with the Company's systems, and is the AMI data being used for billing?

A. PSE&G's primary goal for the CEF-EC program is that after each meter is installed, the customer will receive an accurate bill utilizing an AMI meter read. Following installation of a meter, PSE&G verifies that the meter is communicating with the Company's systems. After three successful days communicating, the billing system utilizes the AMI read to bill the customer. The Company has achieved a sustained AMI actual read billing rate of over 99 percent. Where there have been a small number of communication issues, these are addressed expeditiously.

Q. Regarding the 22 Use Cases, please provide an overview and the status of their deployment.

A. These 22 Use Cases and deployment status are as follows:

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
1,2,3,4	1. Enhanced Customer Engagement & Communications	**Deployed Q3, 2023** (customer access to usage data via portal) **Deployment scheduled Q2, 2024** (enable customer inquiries via portal)	A set of customer benefiting functions and analytic applications that provide visualizations and analytics across a variety of customer and iESP data combined with other data – bills, usage, prices, tips, alerts, energy efficiency, appliance profiles, new products and services, notifications, and available through mobile and web portals.
	2. Rate Analyzer & Comparator	**Deployment scheduled Q3, 2024**	
	3. Usage & Bill Alerts, Saving Tips, Interactive Bill Presentment	**Deployment scheduled Q2, 2024**	
	4. Interactive Energy Demand & Bill Management (Portal part of Meter Data Management System - MDMS project)	**Deployment scheduled Q2, 2024**	
5	Customer Segmentation & Behavioral Analysis	**Deployed Q4, 2023** (pull system) **Deployment scheduled Q2, 2024** (push system)	Provides the ability to develop highly targeted customer segmentation models based on more granular energy usage data and customer interactions to improve customer service, marketing, time of use ("TOU") rates, new products and services, and planning load forecasts. Capability depends on data integration to PSE&G systems to enable usage via "pull system" and "push system"

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
6	Customer Power Quality	**Deployment scheduled Q3, 2024**	Capability that allows PSE&G to obtain voltage, load, and alert data directly from the meter to analyze customer power quality issues (flicker, sag, swell), without the need for further instrumentation, and can also help ensure appropriate corrective actions are taken (utility or customer side of the meter).
7	Customer Energy Efficiency Programs (Thermostats & Supporting CEF-EE Filing)	**Deployed Q4, 2023**	iESP data gives the customer the ability to make more educated energy efficiency related decisions, change energy consumption habits, and ultimately lower utility bills. This is enabled by providing customers with detailed iESP data through web or mobile portals, smart devices and in-home devices. PSE&G can also use this iESP data to design and offer energy efficiency products and services.
8	Customer Service & Call Center Performance	**Deployment scheduled Q3, 2024**	Enables the use of broader range of information (including iESP) to increase call center knowledge, improve service, improve customer satisfaction, and lower customer costs by bringing together historical and real-time information to support decision analysis and improve the customer experience.
9	Customer DER/PV/EV	**Deployed Q4, 2023**	Services and systems that will use iESP data to help assist customers with DER (solar, EV, energy storage) installations and the management of any power quality issues that occur as a result of variable DER load
10	Customer Device Safety	**Deployment scheduled Q3, 2024**	Enhances customer safety by using iESP data, such as alerts and voltage data to detect safety issues relating to customer meters and power connections such as hot sockets and fallen wires, and provide alerts to customers and PSE&G.
11	iESP Sensor, Network & Data Operations	**Deployed Q3, 2023**	Back office processes and systems that manage the initial iESP infrastructure deployment and the ongoing and updated Meter Operations business function including acquisition, warehousing, testing, installation, maintenance, data streams and quality, alarm management, and meter data management.
12	Automated Move in/Move out & Remote Disconnect/ Reconnect	**Deployed Q3, 2023**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a customer move in or out request is issued by Customer Operations or other customer processes. PSE&G currently sends a metering service employee to move a customer in or out for a variety of reasons. With iESP, the turn on functions and on demand read functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes. • Electric operations reduction due to MIMO and Collection activity automated. • Gas operations reduction due to remote MIMO and Collection activity automated: • Cost reduction due to 85k avoided truck roll costs for move in move outs
13	Remote Disconnect/ Reconnect	**Deployed Q3, 2023**	This use case addresses the messages exchanged between Customer Operations processes and Smart Meter through the HeadEnd and Network when a meter connect/disconnect request is issued by Customer Operations or other processes. PSE&G currently sends a metering service or collections employee to connect or disconnect the meter for a variety of reasons. With iESP, the reconnect/disconnect functions to support these processes can be automated and performed remotely and instantaneously, thereby increasing customer satisfaction and efficiency across various customer processes.

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
			• Electric operations reduction due to remote turn-on/off of electric meters • Gas operations reduction due to remote turn-on/off of gas meters: • Cost reduction due to 171k avoided truck roll costs for move in standard turn on/turn offs • Cost reduction due to avoided truck roll costs for turn on/turn off type events • Reduction in writes offs due to energy consumed on inactive accounts. Being able to remotely detect and disconnect will reduce the occurrence. $20m written off yearly. Assuming 70% reduction due to iESP capabilities
14	Next Generation Meter-to-Cash	**Deployed Q3, 2023** (enables billing department to provide revised bills via AMI data) **Deployment scheduled Q3, 2024** (obtain missing interval reads)	With more granular and quality iESP data available, alongside numerous other internal data sources, PSE&G can optimize and re-invent their meter-to-cash processes and drive out inefficiencies, increase service, and reduce costs. The iESP data is significantly more accurate at the source and by mapping the data from the iESP to its end use, leakage can be detected more easily. The cost of these losses is spread across the customer base so any improvement ultimately reduces customer bills. • Billing cost reduction due to a decline of billing irregularities and analysis work • Collection cost reduction due to a decline of backoffice collection workload • Reduction in bad debt due to improvement in field collections. Being able to remotely detect and disconnect will reduce the occurrence. $60m written off yearly. Assuming 31% reduction due to iESP capabilities
15	Network Connectivity Analysis	**Deployment scheduled Q2, 2024**	PSE&G's electricity network is complex, covers a large area, and provides power to different customers at different voltage levels. Ensuring that the required sources and end-use loads are correctly represented in operations systems is often very difficult. The iESP end-point meters can extend the network model and enable a high level of accuracy of connections and phasing, which in turn results in better planning and operations performance, and enables many other network dependent use cases.
16	Outage Detection & Analysis	**Deployment scheduled Q2, 2024**	Uses outage data from operations systems and smart meters to identify and verify possible outage locations, as well as identify network sections and specific customers (and numbers) that are out of power. This data is provided and displayed in real-time, to allow analysis, fast response, and crew dispatch to the precise location (down to meter) with information on the potential cause of the outage in order to more quickly restore power and ensure all customers are restored.
17	Outage Response Notification (ETR)	**Deployment scheduled Q2, 2024**	Use iESP outage data to calculate and communicate reasonable, more accurate, and acceptable outage status and restoration times to customers in real time. This largely eliminates one of the most common customer complaints about utility service, *i.e.,* inaccurate estimated restoration times. Messaging solutions within scope of this use case include Interactive Voice Response (IVR), web portals, text messaging, social media, mobile applications, and press releases.

Use Case #	Use Case Name	Deployment Status	Use Case Overview & Value
18	Voltage Monitoring & Analysis	**Deployment Q3, 2024**	Using iESP data and other network data sources, voltage readings are captured, visualized, and system-wide analysis is run to determine locations where voltage violations exist both above and below nominal voltage. Utilities can utilize this information for accurate analysis of voltage issues and a base for voltage planning and optimization across the network. Further, this information can help planners identify strategic locations for deployment of Volt/VAR optimization equipment.
19	Asset Load/Phase Management, Balancing & Power Analysis (incl. Transformer Load Monitoring & Customer Load Curtailment/Limiting)	**Deployment scheduled Q3, 2024**	Using iESP data and other network data sources, load data is imported, aggregated, and visualized. Power flow analysis is run to examine and monitor loading profiles of every network asset along the feeder from the substation to the smart meter. This use case gives visibility of loading profiles and load flows of all network assets and customers with real-time or overnight iESP data updates. This information can be used by planners and operators to determine areas of overloading of assets on the system, plan responses to major events, execute asset balancing, and customer load curtailment.
20	Load Profiling & Forecasting	**Deployment scheduled Q3, 2024**	Capability that would enhance load profiles and forecasts by using iESP data in combination with network, customer billing or other data (*e.g.*, weather) to perform more detailed usage analysis. This is beneficial to customers and PSE&G planners by supporting optimized planning of load growth, which in turn leads to optimized capital spending and reliability of the network.
21	Distribution Losses	**Deployment scheduled Q3, 2024**	Distribution losses can be identified by comparing the iESP end-point meter usage data with usage data at the distribution entry point (*i.e.*, substation). Areas of high losses or network sections with particularly high losses can be identified through the analysis. Further analysis on the causes of the high losses will shed light into the different types of corrective / mitigating actions that can be taken to reduce the technical losses. Technical losses are spread across the customer base, so any improvement in this area could reduce customer bills.
22	Revenue Protection & Assurance	**Deployment scheduled Q3, 2024**	Revenue protection refers to the prevention, detection, and recovery of losses caused by interference with or theft of utility service. This use case will leverage smart meter consumption, as well as voltage and event data, to detect energy theft and meter tampering by employing multiple screening techniques, including cross-service correlations. Energy theft is spread across the customer base, so any improvement reduces customer bills.

Q. Please identify the Use Cases that have already been deployed.

A. PSE&G has already deployed or partially deployed the following 8 Use Cases:

- Use Case 1: Enhanced Customer Engagement
- Use Case 5: Customer Segmentation & Behavioral Analysis
- Use Case 7: Customer Energy Efficiency Programs
- Use Case 9: Customer DER/PV/EV

- Use Case 11: Sensor, Network & Data Operations
- Use Case 12: Automated Move in/Move out & Remote Disconnect/Reconnect
- Use Case 13: Remote Disconnect/Reconnect
- Use Case 14: Next Generation Meter to Cash

Q. Please describe the benefits currently being realized as a result of the installation and general functionality of installed AMI meters, use of the AMI meter data for billing, and the 8 Use Cases deployed to date.

A. Benefits of the CEF-EC program currently being realized through the CEF-EC program to date can be grouped as follows: meter reading/meter accuracy; benefits derived from remote capabilities; revenue integrity benefits; collections benefits; and customer access to their AMI data. I will generally describe each of these benefit types below:

Meter Reading/Meter Accuracy

Operational and customer benefits result from reduced labor and costs of meter reading and increased accuracy of bills due to a higher meter reading rate due to AMI. Please reference the Company' semi-annual reports in Schedule DJ-2 for meter read rates attributable to AMI.

Remote Capabilities

Currently remote meter reading, remote move-in/move-out, and remote disconnect/reconnect functionalities are enabled and are being used via installed AMI meters. Operational benefits from these functionalities include reduced costs through eliminating the need to dispatch trucks, and the efficiencies of completing these tasks remotely. Through the third quarter of 2023, there have been 10,000 reconnects following disconnection for non-payment completed remotely, avoiding a truck dispatch and greatly reducing the customers' wait time to be reconnected. Additionally, there have been over

125,000 move-ins and move-outs completed remotely (meter reads, turn-ons, and turn-offs). There are also tangential environmental benefits because reducing the need to dispatch a truck reduces the overall greenhouse gas emissions from vehicles.

Collections Benefits

Field collectors now have the ability to disconnect an AMI meter remotely when they update a collection order on their hand-held device. This improves their efficiency and effectiveness. Before having remote turn-on and turn-off capability, the effective rate for a field collector visit was 28%.[6] Since the addition of this capability, the effective rate for a field collector on visits with AMI meters is 88%. There have been over 23,000 move-ins and move-outs remotely turned on and off, resulting in the reduction of unknown accounts and the revenue associated with these accounts (a subset of total remote move-ins/move-outs). In the future, this will result in reduced bad debt expense related to unknown revenues.

Customer Access to Their Data

Customers with AMI meters have access to PSE&G's AMI portal. The portal allows customers to view their usage, set usage threshold alerts, and access existing energy savings tips. The portal available to residential customers also has additional information about home energy assessments.

[6] A field collector visits is typically considered "effective" if it results in either a payment or a shut-off.

Q. Has the Company realized any additional benefits simply by virtue of replacing existing meters?

A. Yes. PSE&G's observations during meter replacement have resulted in PSE&G investigating 9,134 cases of tampering through September 30, 2023. This yields a direct customer benefit, as detecting tampering reduces the costs of theft from meter tampering.

Q. Will AMI meters assist the company in detecting metering tampering and theft going forward?

A. Yes. As described in the table above, the current plan is to deploy an analytical tool by the end of the third quarter of 2024 that will enable identification of potential theft more quickly.

Q. Has the Company implemented the CEF-EC program in a manner consistent with the CEF-EC Order and with regard to customers wishing to opt-out of AMI meters?

A. Yes. The Company has complied with applicable reporting requirements and attempted to implement the program as efficiently as possible. The semi-annual reports submitted to the BPU are attached hereto as Schedule DJ-2. Additionally, the Company has implemented the CEF-EC program in a manner consistent with the CEF-EC Order that fully recognized the rights of customers to opt out of the program. As of November 30, 2023, only 5,559 customers opted out of the AMI meter. This is an opt-out rate of less than one-half of one percent.

Q. Is the Company proposing in this case a change to the manual meter reading fee as was permitted by the CEF-EC Order?

A. No. The CEF-EC Order permits PSE&G to "provide testimony and actual cost information for these fees in its Next Base Rate Case, at which time these fees will be subject to review and modification."[7] However, and in order to achieve an equitable and appropriately non-discriminatory result for all customers, PSE&G is not currently collecting the manual meter-

[7] CEF-EC Order at Stipulation ¶ 31.

reading fees from opt-out customers. Therefore, there is not yet sufficient data to present in this matter regarding the actual costs based on all opt-outs that would support a change in the fee established in the CEF-EC Order. The CEF-EC Order states that "ongoing review and assessment of these fees will be subject to review and modification in future rate cases;" therefore, PSE&G anticipates it will present data related to actual costs of manual meter reads for the entire population of opt-outs in its next rate case.[8]

Q. How does PSE&G communicate these fees to customers that have chosen to opt out?

A. Any customer opting out was notified during the opt-out process that the $12 fee will begin to apply in 2024. PSE&G also intends to send each such customer a letter providing the opportunity to opt back in before PSE&G starts charging the fee. Any customer that opts back in will not be charged a fee.

Q. When will PSE&G begin charging customers the opt-out fees?

A. PSE&G will begin charging a customer an opt-out fee only after PSE&G sends that customer the letter described above providing that customer an opportunity to opt back in.

Q. The CEF-EC Order also established a one-time opt out fee for customers wishing to remove an AMI meter that was previously installed. Is PSE&G currently charging this fee?

A. Yes. PSE&G is currently charging this fee.

[8] *Id.*

IV. ACCOUNTING AND COST RECOVERY FOR CEF-EC PROGRAM

Q. Did the CEF-EC Order establish a method for the Company to account for and recover the costs of the CEF-EC program?

A. Yes. The CEF-EC enables accelerated installation of AMI meters and retirement of legacy and non-AMI meters before they are fully depreciated. The prudence of the costs included in these regulatory assets is subject to review by the Board in this case. The Order provided that until the costs of the CEF-EC programs were rolled into base rates, AMI-related capital costs, legacy meter stranded costs, and AMI-related O&M costs would be deferred and placed in regulatory assets as separate and identifiable accounts. Specifically, the details are shown on Schedule MPM-16, the proposed amortization of the CEF-EC deferrals are shown on Schedule MPM-47, and the *pro forma* revenue requirement adjustment is shown on Schedule MPM-48.

Q. How are the projected O&M savings related to the CEF-EC Program reflected in the Company's filing?

A. In accordance with CEF-EC Order, PSE&G will include a reduction for future O&M savings after the test year. As described in Mr. McFadden's testimony, the Company is proposing a *pro-forma* adjustment to its revenue request in this proceeding to account for future O&M savings resulting from AMI that are not reflected in the test year and is shown on Schedule MPM-48.

Q. Does this conclude your direct testimony?

A. Yes. It does.

Executive Profile

David L. Johnson

Vice President Customer Care and Chief Customer Officer

Public Service Electric & Gas Company

David L. Johnson was named vice president – Customer Care and chief customer officer at PSE&G effective July 2022. In his role, Mr. Johnson is responsible for leading, planning and managing PSE&G's efforts to deliver a seamless and efficient customer service experience, driven by a customer-centric culture. He is responsible for setting the agenda for how the company interacts with customers as well as creating a mindset of continuous improvement to ensure the company is on par with changing customer demographics and expectations.

Mr. Johnson has over 20 years of experience in customer service for energy providers. Mr. Johnson previously served as CCO for Duquesne Light Company in Pittsburg, Pa. and vice president, Customer Service for Entergy Louisiana, where he led day-to-day customer service operations and established and maintained relationships with customers and community stakeholders.

Prior to joining Entergy Louisiana, he was senior vice president, Customer Service and Economic Development, for DTE Energy in Michigan, where he spent most of his career. At DTE Energy, Mr. Johnson led a call center transformation, installation of a new billing system, improved cash collections and built a very solid relationship with internal and external stakeholders.

Mr. Johnson holds a Bachelor of Science degree in accounting from Lawrence Technological University. He is a 2001 graduate of Leadership Michigan and is an active mentor and career coach for young and developing professionals.

Mr. Johnson has served on the boards of several non-profit organizations including Vibrant Pittsburgh, Pittsburgh Symphony Orchestra, Children's Hospital of Michigan, Accounting Aid Society, Junior Achievement, United Way 211 and others. In 2007, he was acknowledged as one of the San Antonio Chamber of Commerce's "Top 40 Under 40." In 2013, he received the highly esteemed "Men of Excellence" award from the Michigan Chronicle. His professional membership includes the American Association of Blacks in Energy.

In his free time, Mr. Johnson is a self-professed classic car lover and enjoys spending time with family.

Clean Energy Futures-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2021-June 30, 2021

Reporting Metric Tables:

Metric Description	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Current Reporting Period 1/1/2021-6/30/2021	Project to Date
Residential Meters Installed	17	1,975	3,613	4,177	6,457	6,880	23,119	23,119
Commercial Meters Installed	2	63	169	314	861	1,151	2,560	2,560
Poles Installed	0	0	0	0	0	0	0	See Note A
Three-radio Network gateways installed	0	0	0	0	0	0	0	See Note A
Single-radio Network gateways installed	0	0	0	0	0	0	0	See Note A
Routers Installed	0	0	0	0	0	0	0	See Note A
Percentage of Network Communicating to L+G Platform	0	0	0	0	0	0	0	See Note B
Total number of opt-out customers	1	11	28	41	56	65	65	65
Number of actual reads recorded from AMI meters each month		997,135	1,239,155	1,431,373	1,815,845	2,204,059	7,687,567	See Note C
Number of meter readers employed by PSE&G each month	357	359	387	416	442	419		
Number of customers who have accessed the AMI web portal	1,083	906	1,149	1,232	1,220	1,232	6,822	6,822
Number of customers identified to have received energy saving messaging	1,817,845	2,725,974	2,550,372	1,553,621	219,038	1,524,373	10,391,223	10,391,223
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Number of AMI meters replaced due to functioning errors	0	0	0	0	0	1	1	1
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

Average Installation Costs Costs			Current Reporting Period 1/1/2021-6/30/2021	Project to Date
Average Cost Residential Meters Installed -Total			**$ 215.91**	**$ 215.91**
Average Cost Residential Meters Installed - Labor			$ 99.88	$ 99.88
Average Cost Residential Meters Installed - Materials			$ 116.03	$ 116.03
Average Cost Commercial Meters Installed - Total			**$ 268.83**	**$ 268.83**
Average Cost Commercial Meters Installed - Labor			$ 128.03	$ 128.03
Average Cost Commercial Meters Installed - Materials			$ 140.80	$ 140.80
Captial and O&M Costs	**FORECAST**		**ACTUALS**	
	Current Reporting Period 1/1/2021-6/30/2021	**Project to Date**	**Current Reporting Period 1/1/2021-6/30/2021**	**Project to Date**
CEF-EC Capital Costs - Total	**$8.56M**	**$8.56M**	**$9.82M**	**$9.82M**
CEF-EC Capital Costs - Labor	$.57M	$.57M	$4.45M	$4.45M
CEF-EC Capital Costs - Material	$1.13M	$1.13M	$3.06M	$3.06M
CEF-EC Capital Costs - Other	$6.86M	$6.86M	$2.31M	$2.31M
CEF-EC O&M Expenses - Total	**$3.34M**	**$3.34M**	**$870K**	**$870K**
CEF-EC O&M Expenses - Labor	$0	$0	$500K	$500K
CEF-EC O&M Expenses - Material	$0	$0	$0	$0
CEF-EC O&M Expenses - Other	$3.34M	$3.34M	$370K	$370K
Stranded Costs Deferred			**N/A**	**See Note H**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 161 new poles and three radio gateways, 47 single-radio network gateways and 2207 routers are estimated to be installed beginning in July 2021 with completion by mid-2022 to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

Estimated Quantity of Work: 100% installation of network to be completed by mid-2022

C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project

D. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. On August 23, 2021, in that docket, the BPU issued a Straw Proposal on Advanced Metering Infrastructure (AMI) Data Transparency, Privacy & Billing, and has sought written comment from all interested parties by October 7, 2021. Per that August 23, 2021 notice, after submission of comments, Board Staff anticipates having one or more stakeholder meetings to discuss that feedback and, once all feedback is received, Staff expects to recommend that the Board approve an MFR order on data access, among other things, which will be followed by a rulemaking proceeding to codify the requirements placed on each electric public utility with an AMI deployment plan. PSE&G is participating in that Board Staff proceeding.

E. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 17 messages:

a) *2 paid Facebook ads,*

b) *15 organic messages on Facebook, Twitter and LinkedIn:*

(1) 5 on Facebook,

(2) 9 on Twitter,

(a) 7 on PSEGDelivers,

(b) 2 on PSEGNews.

c) 1 on LinkedIn

2. Channel followers (as of July 2021):

a) *Facebook: 116,659*

b) *PSEGDelivers (Twitter): 101,704 followers*

c) *PSEGNews (Twitter): 20,418*

d) *LinkedIn: 55,182*

3. The social media posts generated:

a) *2,355,520 impressions (how many times an AMI social message was displayed),*

b) *Reached 797,462 Facebook users*

F. Remote Connects/Disconnects Performed

Use case not yet implemented

G. AMI Metering Tampering Cases

Use case not yet implemented

H. Stranded Costs Deferred

Expected to be available for next reporting period

Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period July 1, 2021-December 31, 2021

Reporting Metric Tables:

Metric Description	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Current Reporting Period 7/1/2021-12/31/2021	Project to Date 1/7/2021 - 12/31/2021
Residential Meters Installed	7,538	8,720	8,663	12,558	6,394	6,007	49,880	72,999
Commercial Meters Installed	973	1,542	1,815	2,322	2,428	2,029	11,109	13,669
Poles Installed	0	0	0	11	14	32	57	57
Three-radio Network gateways installed	0	0	0	10	10	11	31	31
Single-radio Network gateways installed	0	0	0	0	21	3	24	24
Routers Installed	14	236	167	374	483	475	1,749	1,749
Percentage of Network Communicating to L+G Platform	0.64%	12.36%	20.61%	40.14%	66.24%	91.99%	91.99%	91.99%
Total number of opt-out customers	98	111	117	120	128	135	135	135
Number of actual reads recorded from AMI meters each month	2,697,426	3,280,196	3,721,308	4,659,650	5,203,311	6,189,795	25,751,686	See Note C
Number of meter readers and meter reader support staff employed by PSE&G each month	421	415	405	386	363	362		
Number of customers who have accessed the AMI web portal	1,844	1,539	1,789	1,627	1,149	1,378	9,326	16,148
Number of customers identified to have received energy saving messaging	149,173	19,383	1,638,684	2,277,086	2,307,772	11,581	6,403,679	16,794,902
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	0	0	2	1	0	0	3	4
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

Average Installation Costs			Current Reporting Period 7/1/2021-12/31/2021	Project to Date 1/7/2021 - 12/31/2021
Average Cost Residential Meters Installed –Total			**$190**	**$198**
Average Cost Residential Meters Installed – Labor			$75	$83
Average Cost Residential Meters Installed – Materials			$115	$115
Average Cost Commercial Meters Installed – Total			**$242**	**$248**
Average Cost Commercial Meters Installed – Labor			$ 88	$97
Average Cost Commercial Meters Installed – Materials			$154	$51
	FORECAST		**ACTUALS**	
Metric Description (Cost Info.)	**Current Reporting Period 7/1/2021-12/31/2021**	**Project to Date 1/7/2021 - 12/31/2021**	**Current Reporting Period 7/1/2021-12/31/2021**	**Project to Date 1/7/2021 - 12/31/2021**
CEF-EC Capital Costs - Total	**$29.40M**	**$39.22M**	**$23.38M**	**$33.20M**
CEF-EC Capital Costs - Labor	$12.50M	$16.95M	$7.28M	$11.74M
CEF-EC Capital Costs - Material	$7.99M	$11.04M	$8.01M	$11.07M
CEF-EC Capital Costs - Other	$8.92M	$11.23M	$8.08M	$10.39M
CEF-EC Deferred O&M Expenses - Total	**$0.87M**	**$10.03M**	**$3.32M**	**$4.19 M**
CEF-EC Deferred O&M Expenses - Labor	$0.50M	$2.37M	$(0.50)M	$0.00M
CEF-EC Deferred O&M Expenses - Material	N/A	N/A	$0.57M	$0.57M
CEF-EC Deferred O&M Expenses - Other	$0.37M	$7.65M	$3.24M	$3.62M
Stranded Costs Deferred	**N/A**	**N/A**	**See Note I**	**See Note I**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 161 new poles and three radio gateways, 47 single-radio network gateways and 2207 routers are estimated to be installed beginning in July 2021 with completion by mid-2022 to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

Estimated Quantity of Work: 100% installation of network to be completed by mid-2022

C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project

D. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. On August 23, 2021, in that docket, the BPU issued a Straw Proposal on Advanced Metering Infrastructure (AMI) Data Transparency, Privacy & Billing, and sought written comment from all interested parties by October 7, 2021. Per that August 23, 2021 notice, after submission of comments, Board Staff anticipates having one or more stakeholder meetings to discuss that feedback and, once all feedback is received, Staff expects to recommend that the Board approve an MFR order on data access, among other things, which will be followed by a rulemaking proceeding to codify the requirements placed on each electric public utility with an AMI deployment plan. PSE&G is participating in that Board Staff proceeding.

E. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 6 messages:

a) *6 organic messages on Facebook, Twitter and LinkedIn:*
   (1) 1 on Facebook,
   (2) 4 on Twitter,
      (a) 3 on PSEGDelivers,
      (b) 1 on PSEGNews.
   (3) 1 on LinkedIn.

2. Channel followers (as of December 2021):

a) *Facebook: 118,251*
b) *PSEGDelivers (Twitter): 101,942*
c) *PSEGNews (Twitter): 20,673*
d) *LinkedIn: 57,213*

3. The social media posts generated:

a) *18,523 impressions (how many times an AMI social message was displayed),*
b) *Reached 7,242Facebook users*

F. Remote Connects/Disconnects Performed

Use case not yet implemented

G. AMI Metering Tampering Cases

Use case not yet implemented

H. Stranded Costs Deferred

Expected to be available in future reports.

Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2022-June 30, 2022

Corrected copy – 03.01.2023

Reporting Metric Tables:

Metric Description	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Current Reporting Period 1/1/2022-6/30/2022	Project to Date 1/7/2021 - 6/30/2022
Residential Meters Installed	6,596	7,537	8,744	8,064	8,444	17,280	56,665	~~129,664~~ 129,738 See Note J
Commercial Meters Installed	2.367	2,474	3,910	4,188	3,969	4,027	20,935	~~45,713~~ 34,661 See Note J
Poles Installed	9	29	40	11	1	0	90	159 See Note A
Three-radio Network gateways installed	13	38	50	17	5	4	127	159 See Note A
Single-radio Network gateways installed	28	1	0	0	0	0	29	53 See Note A
Routers Installed	338	69	0	14	58	0	479	2,207 See Note A
Percentage of Network Communicating to L+G Platform	89.40%	93.90%	95.96%	97.30%	99.90%	100.00%	100.00%	100.00% See Note B
Number of opt-out customers	12	7	5	4	34	34	96	231
Number of actual reads recorded from AMI meters each month	6,445,369	6,104,754	7,669,478	8,417,578	8,958,500	9,802,700	47,398,379	See Note C
Number of meter reading staff employed by PSE&G each month	366	390	446	449	475	463	See Note D	See Note D
Number of total visits by customers to AMI portal.	1,626	1,273	1,354	1,413	1,499	2,589	9,754	25,902
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meters replaced due to functioning errors	0	0	0	6	6	6	18	21
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note I
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2022) – Period ending June 30, 2022 , Corrected copy – 03.01.2023

Average Installation Costs			Current Reporting Period 1/1/2022-6/30/2022	Project to Date 1/7/2021 - 06/30/2022
Average Cost Residential Meters Installed –Total			**$250**	**$220**
Average Cost Residential Meters Installed – Labor			$136	$104
Average Cost Residential Meters Installed – Materials			$114	$116
Average Cost Commercial Meters Installed – Total			**$335**	**$298**
Average Cost Commercial Meters Installed – Labor			$144	$118
Average Cost Commercial Meters Installed – Materials			$190	$180

	FORECAST		ACTUALS	
Metric Description (Cost Info.)	**Current Reporting Period 1/1/2022-6/30/2022**	**Project to Date 1/7/2021 - 06/30/2022**	**Current Reporting Period 1/1/2022-6/30/2022**	**Project to Date 1/7/2021 - 06/30/2022**
CEF-EC Capital Costs - Total	**$34.45M**	**$67.65M**	**$31.85M**	**$65.04M**
CEF-EC Capital Costs - Labor	$8.96M	$20.7M	$10.23M	$22.26M
CEF-EC Capital Costs – Material	$12.68M	$23.75M	$10.95M	$22.01M
CEF-EC Capital Costs – Other	$12.81M	$23.2M	$10.67M	$20.77M
CEF-EC Deferred O&M Expenses - Total	**$5.66M**	**$9.85M**	**$5.88M**	**$10.07 M**
CEF-EC Deferred O&M Expenses - Labor	$2.36M	$2.36M	$0.46M	$0.46M
CEF-EC Deferred O&M Expenses – Material	$0.20M	$0.77M	N / A	$0.57M
CEF-EC Deferred O&M Expenses – Other	$3.1M	$6.72M	$5.42M	$9.04M
Stranded Costs Deferred	**N / A**	**N / A**	**$28.07M**	**$28.07M**

N/A – Not applicable at this stage of the AMI Program

Reporting Metric Notes:

A. Network Installation

Estimated Quantity of Work: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Percentage of Network Communicating to L+G Platform

Estimated Quantity of Work: Network installation has completed.

C. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

D. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. Additional temporary Meter Reading staff have been hired to support Collection activities and vacations.

E. Number of customers receiving energy saving messages

Reports issued on September 1, 2021 and March 1, 2022 reported data based on all PSE&G electric customers who had received energy saving messages. In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the implementation of use cases 1, 2, 3, 4, 5 and 7. Use cases not yet implemented.

F. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

G. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 4 messages:

a) *4 organic messages on Facebook, Twitter and LinkedIn:*
   (1) 2 on Facebook,
   (2) 2 on Twitter,
      (a) 1 on PSEGDelivers,
      (b) 1 on PSEGNews.

2. Channel followers (as of June 2022):

a) *Facebook: 118,384*
b) *PSEGDelivers (Twitter): 102,165*
c) *PSEGNews (Twitter): 20,860*

3. The social media posts generated:

a) *16,224 impressions (how many times an AMI social message was displayed),*
b) *Reached 14,009 Facebook users*

H. Remote Connects/Disconnects Performed

Use case not yet implemented. A. AMI Metering Tampering Cases

Use case not yet implemented.

I. AMI Metering Tampering Cases

Use case not yet implemented.

J. Correction issued for Meters Installed.

The '**Project to date 1/7/2021 to 6/30/2022**' data figures for line items related to 'residential meters installed' and 'commercial meters installed' was corrected to read as 129,738 and 34,661 meters respectively.

Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period July 1, 2022 - December 31, 2022

Reporting Metric Tables:

Metric Description	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Current Reporting Period 7/1/2022-12/31/2022	Project to Date 1/7/2021 - 12/31/2022
Residential Meters Installed	25,488	32,331	28,198	42,597	63,856	68,761	261,231	390,972
Commercial Meters Installed	3.870	5,765	5,839	6,779	7,248	7,381	36,882	71,563
Network Installed								See Note A
Number of opt-out customers	31	135	200	468	499	351	1,684	1,912
Number of actual reads recorded from AMI meters each month	11,352,467	13,279,195	15,337,058	18,485,408	21,330,381	27,508,752	107,293,261	See Note B
Number of meter reading staff employed by PSE&G each month	449	408	395	371	356	338	See Note C	See Note C
Number of total visits by customers to AMI portal.	2,254	1,412	2,430	2,305	1,574	1,738	11,713	38,613
Number of unique monthly Log-in's to AMI portal.	110	121	106	124	117	108	686	N/A
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	8	11	16	14	31	50	130	152
Number of remote connects/disconnects performed	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note G
Number of AMI meter tampering cases found	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

Average Installation Costs (Per Unit Cost in USD)			Current Reporting Period 7/1/2022-12/31/2022	Project to Date 1/7/2021 - 12/31/2022
Average Cost Residential Meters Installed –Total			**$201**	**$219**
Average Cost Residential Meters Installed – Labor *(1)			$100	$113
Average Cost Residential Meters Installed – Materials			$101	$106
Average Cost Commercial Meters Installed – Total			**$270**	**$285**
Average Cost Commercial Meters Installed – Labor *(1)			$117	$123
Average Cost Commercial Meters Installed – Materials			$153	$162

	FORECAST		ACTUALS	
Metric Description (USD in Millions)	Current Reporting Period 7/1/2022-12/31/2022	Project to Date 1/7/2021 - 12/31/2022	Current Reporting Period 7/1/2022-12/31/2022	Project to Date 1/7/2021 - 12/31/2022
CEF-EC Capital Costs - Total	**$49.2M**	**$116.9M**	**$66.4M**	**$130.8M**
CEF-EC Capital Costs - Labor *(2)	$10.98M	$31.68M	$9.4M	$30.8M
CEF-EC Capital Costs – Material	$19.78M	$43.53M	$32.8M	$55.3M
CEF-EC Capital Costs – Other *(3)	$18.5M	$41.7M	$24.2M	$44.7M
CEF-EC Deferred O&M Expenses - Total	**$5.7M**	**$15.5M**	**$10.0M**	**$20.0M**
CEF-EC Deferred O&M Expenses - Labor *(2)	$2.58M	$4.94M	$3.7M	$4.1M
CEF-EC Deferred O&M Expenses – Material		$0.77M		$0.6M
CEF-EC Deferred O&M Expenses – Other *(3)	$3.1M	$9.82M	$6.3M	$15.3M
Stranded Costs Deferred			**$26.8M**	**$54.8M**

*(1) Average Installation costs - Internal and External Labor.

*(2) Labor - Internal PSE&G Labor.

*(3) Other - Includes all contractors and Outside services.

Reporting Metric Notes:

A. Network Installation

Network Complete: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

C. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. Additional temporary Meter Reading staff have been hired to support Collection activities and vacations.

D. Number of customers receiving energy saving messages

Reports issued on September 1, 2021 and March 1, 2022 reported data based on all PSE&G electric customers who had received energy saving messages. In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the implementation of use cases 1, 2, 3, 4, 5 and 7. Use cases not yet implemented.

E. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

F. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 0 messages:

a) 0 organic messages on Facebook, Twitter and LinkedIn:

(1) 0 on Facebook,

(2) 0 on Twitter,

(a) 0 on PSEGDelivers,

(b) 0 on PSEGNews.

2. Channel followers (as of December 2022):

a) Facebook: 121K

b) PSEGDelivers (Twitter): 101K

c) PSEGNews (Twitter): 21K

3. The social media posts generated:

a) 0 impressions (how many times an AMI social message was displayed),

b) Reached 0 Facebook users

G. Remote Connects/Disconnects Performed

Use case not yet implemented.

H. AMI Metering Tampering Cases

Use case not yet implemented.

Clean Energy Future-Energy Cloud

Advanced Metering Infrastructure (AMI) Program

Semi-Annual Report to the Board of Public Utilities

For the period January 1, 2023 – June 30, 2023

Reporting Metric Tables:

Metric Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Current Reporting Period 1/1/2023 - 6/30/2023	Project to Date 1/7/2021 - 6/30/2023
Residential Meters Installed	80,150	76,707	85,227	79,610	83,894	80,954	486,542	877,514
Commercial Meters Installed	10.148	8,797	12,181	9,476	12,196	8,792	61,590	133,153
Network Installed								See Note A
Number of opt-out customers	414	371	571	622	428	239	2,645	4,557
Number of actual reads recorded from AMI meters each month	29,425,887	31,276,962	37,330,599	45,059,057	49,170,579	54,147,479	246,410,563	See Note B
Number of meter reading staff employed by PSE&G each month	332	312	295	302	331	325	See Note C	See Note C
Number of total visits by customers to AMI portal.	1,961	1,349	1,906	1,728	1,956	1,781	10,681	49,294
Number of unique monthly Log-in's to AMI portal.	131	128	142	116	134	135	786	N/A
Number of customers receiving energy saving messages.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note D
Number of customers who have authorized third party supplier access to their energy usage data	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note E
Third Party Program-to-date customer engagement efforts undertaken by the Company	N/A	N/A	N/A	N/A	N/A	N/A	N/A	See Note F
Number of AMI meters replaced due to functioning errors	32	7	3	9	7	17	75	227
Number of remote connects/disconnects performed	0	0	0	0	0	0	0	See Note G
Number of AMI meter tampering cases found	0	8	2	2	5	1	18	See Note H
Estimated CEF-EC project completion date							12/31/2024	12/31/2024

N/A – Not applicable at this stage of the AMI Program

CEF-EC-AMI Program
Semi-Annual Reporting (2023) – Period ending June 30, 2023

Average Installation Costs (Per Unit Cost in USD)			Current Reporting Period 1/1/20223-6/30/2023	Project to Date 1/7/2021 - 6/30/2023
Average Cost Residential Meters Installed –Total			**$175**	**$194**
Average Cost Residential Meters Installed – Labor *(1)			$58	$82
Average Cost Residential Meters Installed – Materials			$117	$112
Average Cost Commercial Meters Installed – Total			**$256**	**$272**
Average Cost Commercial Meters Installed – Labor *(1)			$89	$108
Average Cost Commercial Meters Installed – Materials			$167	$164

	FORECAST		ACTUALS	
Metric Description (USD in Millions)	Current Reporting Period 1/1/2023-6/30/2023	Project to Date 1/7/2021 - 6/30/2023	Current Reporting Period 1/1/2023-6/30/2023	Project to Date 1/7/2021 - 6/30/2023
CEF-EC Capital Costs - Total	**$114.1M**	**$244.9M**	**$114.7M**	**$245.5M**
CEF-EC Capital Costs - Labor *(2)	$10.0M	$40.8M	$8.8M	$39.6M
CEF-EC Capital Costs – Material	$54.9M	$110.1M	$61.3M	$116.5M
CEF-EC Capital Costs – Other *(3)	$49.2M	$93.9M	$44.6M	$89.3M
CEF-EC Deferred O&M Expenses - Total	**$12.2M**	**$32.2M**	**$8.0M**	**$28.0M**
CEF-EC Deferred O&M Expenses - Labor *(2)	$3.2M	$7.3M	$1.5M	$5.6M
CEF-EC Deferred O&M Expenses – Material		$0.6M		$0.6M
CEF-EC Deferred O&M Expenses – Other *(3)	$9.0M	$24.3M	$6.5M	$21.8M
Stranded Costs Deferred			**$27.0M**	**$81.8M**

*(1) Average Installation costs - Internal and External Labor.
*(2) Labor - Internal PSE&G Labor.
*(3) Other - Includes all contractors and Outside services.

Reporting Metric Notes:

A. Network Installation

Network Complete: 159 new poles and three radio gateways, 53 single-radio network gateways and 2207 routers have been installed to support the expansion of the existing RF Network

B. Actual Reads Recorded from AMI Meters

Actual read number is inclusive of large commercial AMI meters installed prior to start of current AMI Project.

C. Meter Reading Staff

Meter reading staffing fluctuates for various reasons. Permanent Meter Readers continue to decline month over month via natural attrition. In May 2023, additional temporary Meter Reading staff had been hired to support Collection activities and vacations.

D. Number of customers receiving energy saving messages

In this report and subsequent reports, this metric will indicate how many PSE&G electric customers with AMI meters have received messages based on the pending implementation of use cases 1, 2, 3, 4, 5 and 7.

E. Customers who have authorized third party supplier access to their energy usage data

The development of a Data Access Plan has been deferred pending the statewide proceeding in Docket No. EO20110716. PSE&G is participating in that Board Staff proceeding.

F. Third Party Customer Engagement Efforts

PSE&G has utilized social media outlets for third party customer engagement efforts to date. The activities and results are as follows:

1. Published 0 messages:

a) *0 organic messages on Facebook, Twitter and LinkedIn:*

(1) 0 on Facebook,

(2) 0 on Twitter,

(a) 0 on PSEGDelivers,

(b) 0 on PSEGNews.

2. Channel followers (as of June 2023):

a) *Facebook: 117K*

b) *PSEGDelivers (Twitter): 101K*

c) *PSEGNews (Twitter): 21K*

3. The social media posts generated:

a) *0 impressions (how many times an AMI social message was displayed),*

b) *Reached 0 Facebook users*

G. Remote Connects/Disconnects Performed

Use case not yet implemented.

H. AMI Metering Tampering Cases

Use case not yet implemented.